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Impact of the Large-Scale Renewable Energy Target on Wholesale Market Prices and Emissions Levels

NERA
Economic Consulting

Oakley Greenwood

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Project Team

Oakley Greenwood

Greg Thorpe

NERA Economic Consulting

Adrian Kemp

Jordan Narducci

Victoria Mollard

NERA Economic Consulting
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Tel: +61 2 8864 6500
Fax: +61 2 8864 6549
www.nera.com

Oakley Greenwood
GPO Box 4345
Melbourne VIC 3001
Tel: +61 3 9486 8097
Fax: +61 3 8080 0760
www.oakleygreenwood.com.au

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Executive Summary

The expanded renewable energy target scheme commenced in 2010 and aimed to provide 45,000GWh of electricity from renewable sources by FY2020. The scheme obliged electricity retailers to purchase a determined number of renewable energy certificates (RECs) in line with annual targets. From 1 January 2011, RECs were reclassified into two certificate types, namely: large-scale generation certificates (LGCs) and small-scale technology certificates (STCs).

NERA Economic Consulting (NERA) and Oakley Greenwood (OGW) were engaged by the Australian Energy Market Commission (the Commission) to investigate the wholesale electricity price and emissions impacts of the large-scale renewable energy target (LRET) in the National Electricity Market (NEM), the Western Australian Electricity Market (WEM), and in the Northern Territory's Darwin-Katherine system (DKIS).

Our approach involved the development of a reference case, and an examination of a number of scenarios representing variations to the assumptions used in the reference case. The reference case assumed that the LRET was put in place, that there was no formal carbon price, and only profitable renewable investments were allowed to be constructed. Importantly, our reference case presumed that no new coal plants were allowed to be constructed over the modelling time horizon. The alternative scenarios represented a counterfactual of no LRET and no carbon price, and two scenarios where carbon prices were included.

A key feature of the modelling approach used to examine the market implications of each of these scenarios was a consideration of the profitability of generation investments. Market prices were determined using a market optimisation model that:

- determines generation entry and exit to ensure that there is sufficient capacity to satisfy energy demand, given minimum reserve requirements; and
- determines market prices based on the least cost dispatch of generation plants to satisfy demand.

The profitability of generation investments is investigated using an iterative approach of comparing market prices to investment returns for representative levels of demand, and making adjustments until the investment returns are sufficient to support the new entrant generation. This approach is in contrast to alternative modelling approaches, which simply make generation investment decisions based on market requirements to satisfy energy demand, given minimum reserve levels, without investigating the profitability of the subsequent profile of investment.

Our modelling results indicate that:

- the LRET has the effect of reducing wholesale market prices and so lowers revenues for fossil fuel generation compared to the case if there was no LRET;
- under the reference case the proportion of renewable generation energy likely to enter the NEM on the basis of economic returns from energy and REC revenue alone by FY2020 will be approximately 30 to 40 per cent lower than the LRET target; and

- given forecast wholesale market prices, limitations created by the market price cap, cumulative price threshold and the REC penalty price, there is insufficient overall generation investment to meet the reliability standard in some regions.

Importantly, given that it is unlikely that in practice unserved energy will be allowed to rise above the reliability standard as suggested by our results, the resultant wholesale market prices (in particular for the NEM) should be treated as illustrative, rather than as forecasts of likely future prices. Changes to the market parameters, or the introduction of a carbon price, will affect the levels of unserved energy and so also impact on actual wholesale prices.

Our consideration of the scenarios highlights that:

- including a carbon price, results in the LRET being satisfied although the reliability standard remains unsatisfied later in the study period; and
- the penalty price would need to increase to approximately $75 to $80 to bring forward sufficient additional renewable generation to satisfy the LRET.

Our results for the SWIS suggest that the combination of existing and committed renewable plant will satisfy the assumed allocated LRET requirement. Unlike the NEM results, there are no equivalent concerns for unserved energy in the SWIS given the design of the market and more directly managed reserve margin.

Finally, in the NEM the resultant carbon emissions from electricity generation increase by FY2020 in all of the scenarios. By FY2020, emissions in the reference case rise by about 15 per cent compared to FY2011 levels. Under the assumed carbon prices, the increase is lower (between 3 to 5 per cent), while it is higher if there is no LRET (approximately 20 per cent). The effect of the LRET (relative to the counterfactual) is to decrease emissions in the NEM by approximately 5 per cent.

In the WEM, emissions in the reference case are 24 per cent higher in FY2020 compared with FY2011 emission levels. Under the carbon price scenario, the increase in emissions by FY2020 is lower (9 per cent).

1. Introduction

NERA Economic Consulting and Oakley Greenwood have been asked by the Australian Energy Market Commission to examine the wholesale electricity price and emissions impacts of the large-scale renewable energy target, in the National Electricity Market the Western Australian Electricity Market and in the Northern Territory's Darwin-Katherine system.

The study arises in the context of a request by the Ministerial Council on Energy (MCE) to provide an assessment on the likely impacts of the enhanced RET scheme on the prices of electricity, security of energy supply and the emissions levels produced in the energy sector. We understand that our study is one part of the Commission's consideration of these matters, by focusing on the wholesale price implications and the impact on the level of emissions within the energy sector as a result of the LRET.

Our approach to this study has involved:

- conducting a comprehensive review of recent electricity wholesale market modelling studies, in order to develop an appropriate set of assumptions to apply to use in our modelling;
- developing a core scenario for analysis; and
- modelling wholesale market price, capacity additions and retirements, and emissions for the NEM, WEM and the DKIS.

Our primary modelling tool is the CEMOS model, which is a game theoretic model of wholesale electricity markets. CEMOS uses optimisation techniques to solve for the least cost investment in profitable generation capacity to satisfy forecast electricity demand. For this study we have explicitly considered the likelihood that the LRET will be satisfied by FY2020, given the current penalty price, expectations about the technological costs of new renewable generation, and the need to ensure any new capacity will be profitable given market prices.

This report sets out our modelling methodology, assumptions and results in detail. It is structured as follows:

- section 2 describes the model in detail, and how we have approached the task of considering the LRET;
- section 3 provides details of the modelling assumptions used; and
- section 4 presents the modelling results and conclusions.

In addition, Appendix A sets out detailed data inputs and Appendix B provides more detailed modelling results.

2. Methodology for Modelling Wholesale Market Impacts of the Large-Scale Renewable Energy Target

This section provides a brief overview of our approach to the market modelling and the scenarios considered.

2.1. Approach to Market Modelling

To investigate wholesale market impacts of the LRET, we have used a market optimisation model that:

- assesses generation entry and exit to ensure there is sufficient capacity to satisfy energy demand, given minimum reserve requirements and any other constraints; and
- determines the least cost dispatch of generation plants to satisfy energy demand requirements.

Particular features of the market are captured in the modelling framework through the use of constraints to the optimisation problem. For example, we constrain the generation capacity formulation to ensure that a minimum level of renewable generation is available in the market.

Models of this type can be configured to provide long-term strategic views about:

- the future portfolio of generation capacity;
- dispatch of individual plants;
- carbon emissions;
- fuel use;
- capital and operating costs of generation;
- wholesale electricity market prices;
- transmission network requirements; and
- cost of the LRET.

When the model is linked to detailed half hourly (or even shorter) market dispatch models, short-term volatility of wholesale prices, generator dispatch, ancillary services, and network losses can also be investigated. This also allows for an analysis of investment, market dispatch and associated wholesale prices using market based bidding behaviour, or based on cost based information.

Importantly, in energy only markets such as the NEM, simply dispatching generation on the basis of the short-run operating costs of generation plants does not provide insights into wholesale market prices because it does not include the capital premium needed for the marginal generating unit, to provide sufficient incentives for new generating capacity investment. Other methods are therefore required to ensure that resultant wholesale market prices are adequate to ensure that required generation capacity recovers its capital costs. As a consequence market models that simply dispatch on the basis of short-run marginal cost, and determine the least cost combination of generation required to satisfy demand, cannot be used to assess wholesale market prices.

Similarly determining generation investment based only on the least cost combination of generation dispatch to satisfy demand is useful to assess the make-up of the most efficient generation portfolio, but does not provide insights on what investment will be delivered within the market. Or put another way, least cost assessments assume that the market design and market settings (such as the market price cap) will not be a barrier to realising the most efficient portfolio.

The capital premium required to fund the capital costs of the marginal generating plant is sometimes represented as an explicit capacity payment, for example in markets where a separate capacity market operates like the WEM.

Our approach in this project has been to determine the impact of the LRET on wholesale market prices in the two organised competitive markets in Australia – the NEM and WEM. We looked at emissions and the achievement of the LRET in these markets under a number of specific scenarios that were designed in conjunction with the Commission.[1] As a consequence we were particularly interested in determining whether the required portfolio of fossil fuel and renewable generation investments needed to satisfy both the LRET and energy demands, recovered its costs from the market prices generated. Accordingly we configured our models to provide a basis for internally consistent comparisons between the scenarios and to provide an opportunity for sensitivities to be considered around the key input parameters. Outside the organised markets we assumed cost recovery of generation costs to meet demand.

For our analysis of the NEM this required us to consider:

- market based bidding;
- the impact of generator behaviours and performance (ie, outage rates);
- implications from variations in electricity demand due to factors such as a carbon price; and
- whether new generation investments were economic given forecast wholesale market prices.

This last point was particularly important to our analysis in the NEM, so we ensured that our portfolio of new generation investments were based on an assessment of the commercial return to investors, rather than a pre-determined reserve margin. In addition, we compared the forecast level of unserved energy with the NEM reliability standard, to determine whether it was satisfied.

For our analysis of the WA South West Interconnected System (SWIS), our approach involved ensuring that new entrant generation investment satisfied the reserve margin standard within the WA market rules from which we calculated the resultant price.

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[1] The scenarios are described in section 2.3 below.

In practice, our assessment of the profitability of generation investments involved an iterative approach of comparing prices to investment returns, and making adjustments until investment returns were sufficient to support the new entrant generation. The existing generation portfolio is represented on a physical station basis and new entrants by a single station for each technology type in each region for each cost tranche.[2] If necessary existing stations can also be broken down to a unit level. This approach is highly transparent and ensures that internally consistent comparisons can be made between scenarios.

The CEMOS model uses a load duration curve or load block approach to modelling demand, which is commonly used in optimisation models of electricity markets to manage modelling complexity and the size of the computing task. A load block modelling approach breaks annual demand as represented by a load duration curve[3] for each year in each region into a number of representative slices. A mathematical optimisation algorithm is used to find the optimal generation investment and dispatch needed to satisfy demand in each block, subject to all relevant operating constraints, for each year and region being considered.

For analysis of the NEM the model is configured to use a game theoretic approach to find the optimum bid prices for the level of demand and availability of generation and in this way determines bid prices on which dispatch is based. This is not necessary for the WEM as market rules and the separate capacity market mean that efficient outcomes and adequate investment returns can occur with dispatch based on short run marginal cost.[4]

Two separate sets of runs are undertaken with different demands representing demand with a 50 per cent probability and 10 per cent probability. The results are then amalgamated into a weighted average. The process is repeated as necessary until the amalgamated result achieves the particular objective of the case being studied. For example, to determine prices that ensure that new thermal investment is profitable, or the additional revenue needed from the sale of RECs (capped by the penalty price) ensures new renewable investment will be profitable. Alternatively, to ensure that that unserved energy is controlled to no more than the reliability standard. This iterative approach can be time consuming but it is very transparent and not as reliant on the design of algorithms that might be written to optimise to each objective. As a result comparisons between cases are more reliable.

2.2. Future Generation Portfolio in the NEM

As indicated above, we have been particularly mindful of determining whether the future generation portfolio in the NEM is financially viable given forecast market prices. This has involved analysing the profitability of new investment, the profitability of investments to

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[2] Different "stations" are used to represent a new technology where the cost is expected to fall over time, for example if the capital cost was progressively falling over a number of years a different station would be used to represent the cost between say 2010 and 2015 and another station for the (lower) cost for the years 2016 -2020 etc. Because the model would select the lowest cost options when new entry is needed after 2015 it would always prefer the 2016-2020 "station"

[3] A load duration curve plots demand against the number of hours that each demand level occurs.

[4] Strictly speaking this only occurs if the overall portfolio of generation has the ideal mix of base intermediate and peaking technologies. This may not be the case in the first few years but the model will deliver new investment that will trend to outcome to the ideal mix over time.

satisfy the LRET after accounting for additional revenue from RECs, and the associated level of unserved energy relative to the 0.002 per cent of demand reliability standard.

Investment in the NEM can be limited by the overall revenue available as a result of:

- the market price cap currently set at $12,500/MWh, which particularly affects investment in very low duty cycle peak plants that are crucial for reliability;
- contract premiums; and
- internal investment criteria within vertically integrated businesses.

We found that in a number of cases, the initial modelling results did not result in the simultaneous satisfaction of the unserved energy standard, when only profitable renewable and new entrant gas plant generation was allowed to enter the market, and where the LRET was satisfied. Accordingly, we developed a number of cases where two of the three objectives were met (eg, profitability of new entrant generation and satisfaction of the LRET), and the other market parameter was allowed to 'float'. In general we gave priority to assessing the impact on the LRET and on ensuring profitable entry of new plant.

The profitability of new entrant fossil fuelled generation was assessed from the ratio of:

- market revenue based on modelled spot market outcomes; and
- total annual costs (= annualised capital costs + variable operating cost + fuel costs + carbon cost).[5]

Profitable investment was considered to occur when the ratio of revenues to costs was greater than one.

New renewable generation investments were determined based on the LRET obligations, making adjustments for additional renewable contributions from the GreenPower scheme, and for contributions from non-scheduled generation.

The profitability of new entrant renewable generation was based on summing the revenue earned from spot market outcomes and the revenue from the sale of large-scale generation certificates. The LRET regime requires the surrender of one Large Generation Certificate (LGC) or the payment of a penalty for each MWh of a retailer's renewable energy obligation.

Retailer obligations in the SWIS were based on a pro-rated demand share, namely 5.5 per cent of the national total target. If necessary we would have iterated between the different markets to optimise costs and so assumed parties in a region were buying LGCs from outside their home market. In the end we did not pursue this option as it became clear that initial results were adequate to address the questions we have been asked. In particular we found that the existing and committed investments will allow the local SWIS requirement to be met.

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[5] This implicitly assumes that longer term contract prices reflect spot market prices.

We have also assumed that no additional renewable plants would be added to the SWIS network to contribute to the satisfaction of the NEM's proportion of the LRET. This was considered appropriate because the primary source of renewable technology in the SWIS prior to FY2020 will be low inertia wind generation[6] Any additional renewable plant would therefore create significant risks for the relatively small SWIS power system, and so would not likely be viable.

We investigated the impact of the LRET by modelling the situation where renewable plant was allowed to enter only if it was profitable on the basis of market revenue and support from the RECs and also a case where the LRET target was enforced even if this implied renewable investment in excess of the (tax effective) penalty price.

We judged this approach was pragmatic and able to give consistent comparisons across the scenarios. To illustrate the difficulties that might otherwise arise, consider that wind resources are currently being installed with the average cost of the wind plant being at least $100/MWh yet the prevailing energy contract price is of the order of $40/MWh and the REC price is $30-$35, which leaves a substantial gap. Clearly there are other factors at work – such as large contract premiums for renewable plants, previously banked certificates and the impact of transition arrangements in the split of the scheme into small and large scale targets as well as strategic expectations of future prices within a carbon price. We have therefore modelled each case on a consistent first principles basis in order to understand the differences between cases.

2.3. Modelling scenarios considered

To examine the wholesale price implications of the LRET, we have examined three principal scenarios, namely:

- Reference case – LRET no carbon price;
- Counterfactual – No LRET and no carbon price;
- Carbon Price Scenario 1– LRET and scenario 1 carbon price; and
- Carbon Price Scenario 2- LRET and scenario 2 carbon price.

The detailed assumptions and inputs are set out in greater detail in Appendix A.

A high-level description of the key differences between the scenarios is set out below. The detailed assumptions and inputs are set out in greater detail in Appendix A.

2.3.1. Reference case – LRET with carbon price uncertainty

Our main scenario involves the continuation of the current LRET policy settings and approach to pricing carbon, namely:

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[6] Low inertia generation plant requires higher and more costly levels of ancillary services to ensure system security can be maintained

- a LRET target of 41,000 GWh (nationally) by FY2020, with a fixed (non-indexed) penalty price of $65/MWh[7] - as laid down in legislation;
- no formal carbon tax or emissions trading scheme;
- inclusion of existing and proposed new entrants that meet the AEMO threshold for committed status and the IMO equivalent for the SWIS are included;
- upgrades of existing NEM coal units as advised to the AEMO and included in the 2010 Electricity Statement of Opportunities have been included, in addition to the published refurbishment of Muja Power Station D and C in the SWIS;
- formally announced retirements are incorporated; and
- no other new coal plant is included, to reflect the significant uncertainty of investors about the future of a carbon pricing regime as well as state government limitations on the emission intensity of new generating plant.

This reference case was developed in consultation with the Commission, as indicative of the conditions where no formal carbon price is introduced.

2.3.2. Counterfactual – No LRET with carbon price uncertainty

The counterfactual presumes that renewable generation is capped at the existing amount and committed investments and any additional renewable investment would only occur if it was economic in its own right. Other than committed coal plants no new coal is included. This scenario allows us to examine the implications of the LRET.

2.3.3. Carbon Price Scenario 1 – LRET and scenario 1 carbon price

The third scenario examined the implications of introducing a carbon price to the reference case. We have assumed the carbon price is introduced from FY2012, with the carbon price trajectory reflecting the CPRS -5% modelling undertaken by Commonwealth Treasury in relation to the previous CPRS.

2.3.4. Carbon Price Scenario 2 – LRET and scenario 2 carbon price

The last scenario also examined the implications of introducing a carbon price to the reference case. We have assumed the carbon price is introduced from FY2012, with the carbon price trajectory provided to us by the Commission.

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7 Assuming a company tax rate of 30 per cent, this is equivalent to a price of $92.86/MWh in 2011. This penalty price was legislated in January 2011. However, all other aspects of our analysis are based on financial years. Therefore, we have assumed that the penalty price remains at $92.86 through June 2012 and then decreases in real terms each financial year by the rate of inflation. Notably, the tax effective penalty price is the maximum price companies would pay as some companies may be able to minimise their effective tax.

3. Key modelling assumptions and inputs

This section sets out the modelling assumptions that have been used for the study. Our approach to developing these assumptions involved undertaking a detailed review of assumptions and inputs used by recent electricity market studies, and wherever possible using publicly available market information for each parameter.

The key sources for these parameters and the associated reference materials are:

- Australian Energy Market Operator, (2010), *National Transmission Network Development Plan Modelling Assumptions: Supply Input Spreadsheets,* 23 August;
- Australian Energy Market Operator, (2010), *National Transmission Network Development Plan Demand Forecasts*, 8 June;
- Australian Energy Market Operator, (2010), Electricity Statement of Opportunities (ESOO); and
- KPMG Econtech, (2010), *Economic Scenarios and Forecasts for AEMO – 2009 Update*, 11 February.

The AEMO data is published with reference to a number of market scenarios, which reflect possible differences in economic growth, fuel prices, energy demand and approach to carbon pricing. The scenarios were developed in conjunction with the Commonwealth Department of Energy Resources and Tourism's (DRET) preparation for an Energy White Paper. We have chosen to use Scenario 3,[8] which assumes moderate economic growth, moderate oil and gas prices with relatively high domestic gas demand, medium domestic LNG production and new gas supplies in the eastern states. For Western Australia, prices for new domestic gas purchase are higher than on the east coast and more reflective of international prices and stable coal prices. Finally, the capital costs for new plants in Scenario 3 are approximately the medium for the range predicted across all of the scenarios.

The remainder of this chapter discusses the assumptions and inputs used in greater detail.

3.1. The Renewable Energy Target

The Australian government has agreed to introduce a renewable energy target obligation for electricity retailers, whereby 41,000GWh of renewable energy each year must be purchased from large generation facilities by FY2020. This target has been based on the government's commitment to source approximately 20 per cent of Australia's electricity from renewable sources. The target is planned to be maintained until FY2030 after which the scheme will end.

On 1 January 2011 the Renewable Energy Target was split into the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). As a consequence of this split:

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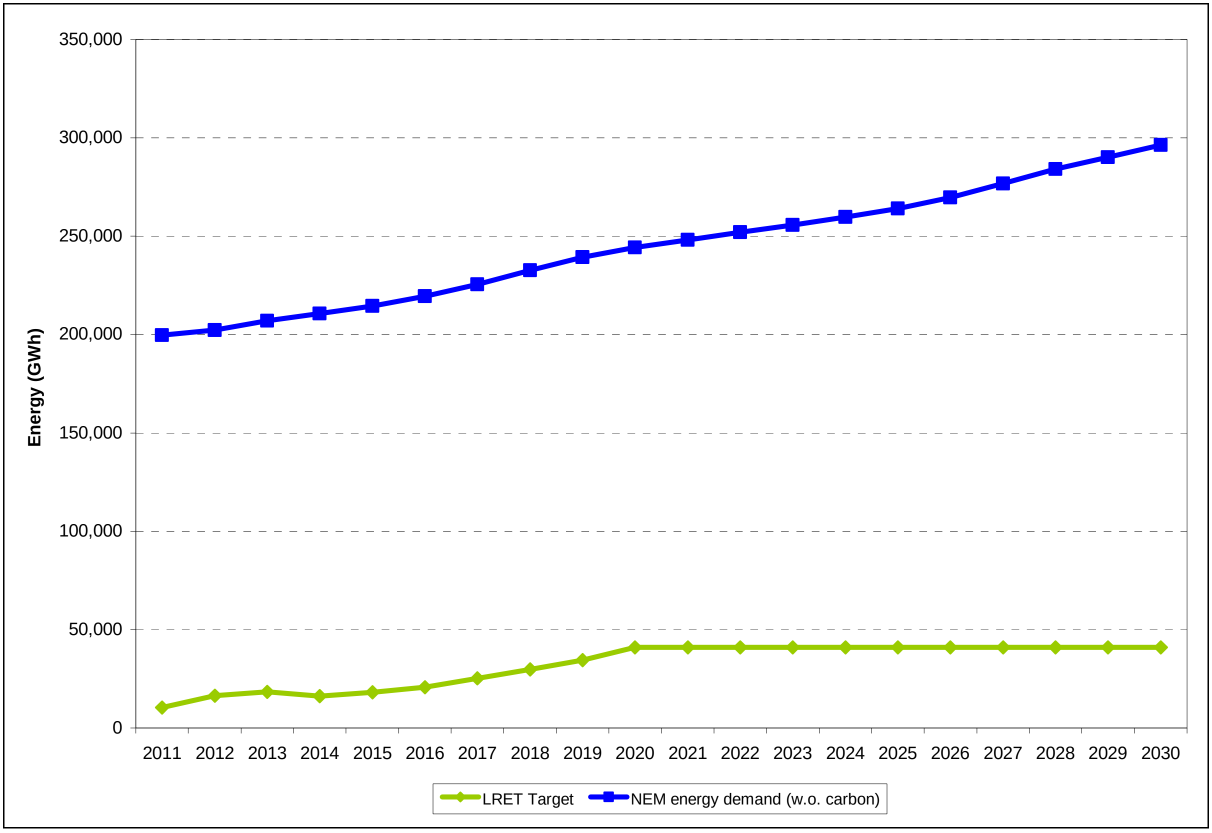
[8] See AEMO, NTNDP Supporting Data Input Data base, <http://www.aemo.com.au/planning/2010ntndp_cd/home.htm>.

- RECs created from 2001 to end 2010 were reclassified as Large-scale Generation Certificates (LGCs);
- renewable energy power stations will create LGCs from 1 January 2011; and
- RECs created for Solar Water Heaters (SWH) and Small Generation Units (SGU) installed after 1 January 2011 will be classified as Small-scale Technology Certificates (STCs).

The LRET scheme commenced on 1 January 2011, with the target introduced in line with the schedule set out in Figure 3.1 and published by the Office of Renewable Energy Regulator.[9]

Figure 3.1: Large-Scale Renewable Energy Target and Total NEM-Wide Energy Demand



Source: ORER website ,http://www.orer.gov.au/new.html#lrettarget.; and AEMO, 2010 NTNDP study; and "2010 NTNDP Energy and MD Forecasts.xlsx", see: http://wwww.aemo.com.au/planning/2010ntndp_cd/home.htm.

In setting the requirements in the modelling, we have taken into account existing and committed renewable plant investments and Green Power based renewable energy certificates (RECs).

9 See ORER website for details of the transfer that was undertaken, <http://www.orer.gov.au/new.html#lrettarget>.

As noted above, we allowed the model to bank additional investment in renewable plant but did not explicitly model the REC market. This means our renewable investments and implied REC prices may not align with current REC market prices. We accepted this position because the REC market is influenced by a number of factors, including: surplus certificates; the impact of transition arrangements related to the split of the scheme into LRET and SRES; and general uncertainty within the investment community about the timing of future policy initiatives. A scenario approach would be necessary to assess the impact of REC prices but we were seeking to make a comparison between situations with and without the LRET and so considered a first principles approach to examining renewable investments to be more appropriate.

Finally, the reference case initially apportions the LRET target between the three wholesale electricity systems considered (ie, the NEM, SWIS and the Darwin Katherine Interconnected System) on a pro rata to demand basis. If in the course of the modelling we had found significant disparities between the level of market based renewable investment in one location, we would have examined the possibility of sales of RECs between the systems. However, after conducting the modelling we did not find that significant disparities occurred.

3.2. Carbon prices

The reference case that we have been asked to consider assumes that there is no formal carbon price mechanism (ie, no carbon tax or emissions trading scheme). That said we have assumed that there are restrictions on new coal plant investments. This reflects the current uncertainty that is leading investors to shun new traditional coal based investments. It is recognised that a complete absence of new coal investment in the SWIS may lead to an over reliance on gas. On the data used for the analysis, coal would be a lower cost option and so prices may be lower overall if coal was allowed; although very recent events surrounding the coal supply to the SWIS makes forecasting new coal prices more complex.

In addition, we have examined the sensitivity of our reference case results to the introduction of two carbon price scenarios commencing in FY2012. The first scenario is based on the starting point around the level that has been discussed for the previous CPRS and increased at 4 per cent real per annum, also as expected under the previous CPRS.[10] The second scenario was provided to us by the AEMC. The resultant carbon prices for each financial year until FY2030 are set out in Table 3.1.

[10] We are not aware of any formal statement of a revised carbon price schedule to replace the previous CPRS schedule starting in 2010 although a number of parties have published work based on slightly different assumptions similar to the schedule we have adopted – for example AEMO in its work for the NTNDP.

Table 3.1: Carbon Price Assumptions

Year	Scenario 1 Carbon Price ($2010/11)	Scenario 2 Carbon Price ($2010/11)
FY2011	0.00	0.00
FY2012	24.00	25.00
FY2013	24.96	26.17
FY2014	25.96	27.42
FY2015	27.00	28.92
FY2016	28.08	30.28
FY2017	29.20	31.67
FY2018	30.37	33.19
FY2019	31.58	34.75
FY2020	32.85	36.60
FY2021	34.16	38.65
FY2022	35.53	40.82
FY2023	36.95	42.86
FY2024	38.42	45.27
FY2025	39.96	47.20
FY2026	41.56	49.73
FY2027	43.22	52.38
FY2028	44.95	54.66
FY2029	46.75	56.83
FY2030	48.62	59.36

Note: Carbon prices represent financial years (eg, FY2011 is 2011/12)

3.3. Committed generation plant new entry and existing plant retirements

The modelling framework determines new generation entry required to satisfy expected electricity demand, given both existing plant and information on planned plant retirements and new plant investments. We include all new generation projects that have reached the committed status, as defined by the AEMO in the NEM and facilities that have achieved capacity accreditation in the WEM. In addition, we schedule economic retirements based on the model outcomes, where plant revenue is found to be insufficient to service plant operating requirements – although as the discussion of results notes we did not find a case for economic retirement given an assumed rising gas price that results in market prices that are sufficiently high to ensure coal plant is profitable. However a number of plants approach the point where retirement would occur by the end of the modelling horizon.

Table 3.2 sets out the new entrant scheduled and semi scheduled projects have committed status in the NEM.

Table 3.2: Committed Scheduled and Semi-Scheduled New Entrant Projects in the NEM

Name	Size (MW)	Jurisdiction	Scheduled for Completion
Oaklands Wind Farm	42	Victoria	2011/12
Mortlake OCGT	518	Victoria	2011
Hallet 4 Wind Farm	132	South Australia	2011
Hallet 5 Wind Farm	53	South Australia	2012
Lake Bonney 3 Wind Farm	NA	South Australia	2011
Waterloo Wind Farm	NA	South Australia	2011

Source: AEMO, (2010), ESOO, published.

For the WEM, the capacity credit process operates three years in advance, and so provides certainty about future capacity over this period.[11] The IMO seeks to accredit capacity from existing and new entrants to at least satisfy the minimum capacity reserve required under the WEM market rules.

A summary of announced retirements in the NEM is set out in below in Table 3.3.

Table 3.3: NEM Retirement Plans

Station	Year	MW reduction	Comment
Munmorah	2015	600	
Playford	2018	240	Subject to review (inconsistent with ESOO)
Swanbank B unit 3	2011	120	
Swanbank B unit	2012	120	Stations fully retired
Mackay GT	2016	27	Subject to review

Source: AEMO, (2010), ESOO, published.

3.4. Marginal loss factors

Marginal loss factors (MLFs) represent the impact of transmission losses from a generator to the relevant regional reference node. They are used to scale regional reference node prices to calculate revenues for generators (and also for customers).

[11] The most recent capacity credit listing is available at http://www.imowa.com.au/f180,602869/ Summaryof_Capacity_Credits assigned_by_Facility_for_the_2010_Reserve_Capacity_Cycle.pdf.

We have used the relevant MLFs as applied by the AEMO and the IMO, as appropriate.

3.5. New entrant technology parameters

The new generation entrant technology parameters are based on those developed jointly by AEMO and DRET noted earlier. Values for selected key technologies are summarised in Table 3.4 below.

Table 3.4: Capital Costs

Technology	Installed capital cost $/kW	First date available (subject construction period)
Wind (200MW)	2,693	Now
OCGT	947	Now
CCGT	1302 (10%, 30%)	Now
Geothermal	7,416 (EGS) 7,017 (HSA)	Commencing 2015
Super critical black coal	2587 (15%)	Now
Super critical brown coal	3,452	Now

Note: Installed capital costs are for the NEM in 2020 and are expressed in $2009/10. Percentage adders for WA WEM and DKIS are shown in parentheses, as a result of their smaller scales.

Source: AEMO, (2010), 2010 NTNDP: National Transmission Network Development Plan, Supporting Data – Input Database, Input Assumption Tables.

The construction of new entrant technologies can be limited by:

- the availability of construction resources; and
- the availability of fuel resources.

We apply these resource limitations within the model when determining the mix of new entrant technologies needed to satisfy generation capacity requirements. Key limitations are presented in Table 3.5. These are also taken from the AEMO/DRET data but in order to simplify the modelling we have worked with regional values formed by aggregating sub regional values within the source data.

Table 3.5: Resource Limits – Regional Aggregate (MW)

Technology	QLD	NSW	VIC	TAS	SA	WA
Wind	2,130	7,748	6,541	3,148	5,964	1,223
OCGT	Economic	Economic	Economic	Economic	Economic	Economic
CCGT	Economic	Economic	Economic	Economic	Economic	Economic
Geothermal EGS	500	500	1750	750	3350	700

Source: ACIL Tasman, (2010), Preparation of Energy Market Modelling Data for the Energy White Paper, Supply Assumptions Report, 13 September 2010.

3.6. Fuel costs

The AEMO annually publishes its forecasts of fuel costs for twenty years into the future, for each generating plant within the NEM. These forecasts are developed as part of the ESOO and national transmission planning process and take into account a number of factors including generation fuel type and source, the scope for export of the fuel, transport costs, and the cost of mining, where relevant. Forecasts are also provided for areas outside of the NEM, including the WEM. To ensure consistency in the forecasts, we have also used the AEMO fuel price forecasts for our price modelling for the WEM.

The gas price assumptions result in an increase from \$3.50/GJ - \$4.00/GJ to approximately \$6.00/GJ to \$7.5/GJ by FY2020 (in \$2009/10) in the NEM. These prices are consistent with expectations about LNG facilities coming online in Queensland from late 2013. This is leading to a slight decrease in gas prices particularly in Queensland as gas is produced in the period leading up to commissioning of the plants, followed by an increase as domestic gas prices progressively shift towards export parity prices. The additional gas prior to plant commissioning is commonly referred to as 'ramp gas'.[12]

Gas prices for the WEM are uncertainty and expected to rise significantly when the contracts under which a significant percentage of gas for electricity generation is supplied expire from around FY2016. This is expected to result in gas prices increasing from around \$2-3/GJ to approximately \$7/GJ (in \$2009/10), plus transport costs of approximately \$1/GJ (in \$2009/10) for high capacity factor pipeline use. This will mean the WEM and NEM gas prices will broadly align, although the prices in the NEM are less certain because they are dependent on the status of development of LNG and gas contracting activity for electricity generation.

Estimates of the price-volume relationship for gas were developed during work for the Energy White Paper and used as a reference point – the gas consumption in our studies and price in the studies were cross checked against this relationship and found to be reasonably

[12] One key difference between LNG plants that use coal seam methane as a feedstock and those that use conventional natural gas is that once the wells are brought into production they effectively must stay in production and this may occur before the facilities that will consume the gas in the long term are complete. The resultant gas production is referred to as 'ramp gas' as it occurs during the "ramp up" period of a project.

aligned. A key source of uncertainty about gas price in the NEM is the timing of the expected alignment with a netback price with LNG. For the WEM where gas production has been linked to LNG in the north of the state for many years but contracted at prices well below the LNG netback price there is uncertainty about the outcome of commercial negotiations and the impact of the state's DOMGAS policy, which obliges producers to offer a minimum volume for domestic use.

3.7. Electricity Demand

The AEMO publishes annual forecasts of total electricity demand and summer/winter maximum demand for each region of the NEM as part of the ESOO. AEMO also develop a range of forecasts for scenarios studied in conjunction with DRET. In addition, AEMO publishes the energy to be supplied by scheduled, semi-scheduled and non-scheduled generation, and the contribution expected from non-scheduled generation. The demand in the SWIS is based on forecasts developed by the IMO and is based on scheduled generation only.

Although the AEMO forecasts vary by scenario in the joint AEMO/DRET study, none explicitly provided forecasts for no carbon within scenario 3. We therefore developed a forecast for the reference case based on the mid-point for demand without carbon but with high growth (AEMO/DRET scenario 5-ALT) and the low growth case (AEMO/DRET scenario 2-ALT).

As the demand supplied by the NEM is the demand met from scheduled and semi-scheduled and we applied the factors nominated by AEMO in the ESOO to derive these from projections of total demand.

The peak demand (as generated) and energy (sent-out) forecasts (less non-scheduled generation) used in this study are set out in Appendix A.

3.8. Capacity contribution of intermittent generation

We assumed wind (as the primary intermittent generation technology that emerged in the results) would contribute:

- 3% of installed capacity at peak times in the NEM; and
- 20% in the SWIS.

These values are consistent with reliability assessments by the AEMO and align with a current rule change proposal by the IMO for the SWIS.

3.9. Emissions

For the cases with carbon prices we have assumed that prices will include the impact of fugitive emissions as generators will either be directly accountable for fugitive emissions or fuel suppliers will be able to pass carbon imposts on them through in prices.

We have reported emissions as inclusive of both combustion plus fugitive emissions.

3.10. Wholesale prices

In the NEM the wholesale price is a direct outcome of the modelling. Initial results from market models of the type used for this study are constrained by the starting point formed by the current portfolio and any committed entry or exit. Depending on the initial portfolio and the nature of constraints imposed on the solution (such as the LRET target) an efficient model will, over time, determine optimum new investment and generally find a price based on the cost of new entrants.

The initial years of a study can be compared with recent actual results but may differ from them. Differences can be due to the model using long term forecasts rather than actual demand and actual maintenance programs in place of long term rates. In addition traders will have partially built their contract book and this will have some influence on bidding behaviour in the face of uncertainty about the future, whereas the model will assume typical contract situations and bidding based on assumed full knowledge of the future. As a result prices beyond the first two to three years of a model will be more closely related to fundamentals while prices in the first two years may be influenced by detailed methodology within a model. This is particularly the case for the NEM.

In the SWIS we have assumed bidding will be constrained to short run costs based on fuel price and the technical characteristics of plant. We have developed the price for the SWIS by finding the marginal dispatch price based on the short run cost as representative of efficient operation and pricing in the STEM and balancing markets. We have added an estimate of the capital cost of open cycle gas turbine plant based on the costs in our base data from the AEMO/DRET studies to represent the capacity payment under the WEM rules. In the event the actual capacity payment is different we would expect this will be reflected in bilateral contract prices but that STEM and balancing market prices will continue to reflect SRMC.

For the DKIS we have calculated prices based on cost recovery for the generation portfolio needed to meet demand.

This is a relatively simple exercise as the P&WC have long term contracts for the supply of gas and the generation profile is dominated by a single technology (OCGT).

4. Modelling results

4.1. Overview

Our approach to modelling the implications of the LRET on wholesale market prices in the NEM and the SWIS has involved a detailed examination of the generation investment needs (both renewable and fossil-fuelled), and the economic feasibility of satisfying demand requirements and the LRET, given current market parameters and the structure of the LRET.

A key observation from the study is that the impact of the LRET scheme is complex. The LRET target profile rises until FY2020 and investment to meet the target depends on profitable returns from the market plus the sale of RECs. However, the market price is distorted by the investment that is underwritten by the RECs. Market prices are capped by the market price cap, currently set to $12,500/MWh and the revenue from the sale of RECs is likely to be limited by the penalty price under the LRET arrangements, which determines the price at which it is better for a retailer (or other responsible demand) to pay the penalty price rather than invest in renewable plant. The market price is also a function of gas prices.

Calculation of the impact of LRET on the wholesale market is found from the difference in estimates of price between cases “with and without” the LRET. However, in addition to inherent complexity of the analysis noted in the previous paragraph these estimates are themselves very sensitive to assumptions about capital and operating costs of existing and new generation plant, new entrant resource availability and also demand forecasts. As a result minor differences in assumptions in the derivation of the “with and without” LRET cases can greatly exaggerate differences in the assessed impact of LRET.

Further complications arise in the NEM as we found that in the reference case it is unlikely there will be an economically feasible set of renewable and generation investments that will satisfy the generation reliability standard and meet the LRET. Given our modelling assumptions, the results suggest that:

- under the reference case the proportion of renewable generation energy likely to enter the NEM on the basis of economic returns from energy and REC revenue alone by FY2020 will be approximately 30 to 40 per cent lower than the LRET target;
- the LRET reduces wholesale market prices and so lowers revenues for fossil fuel generation compared to the case if there was no LRET; and
- given forecast wholesale market prices, and limitations created by the market price cap, cumulative price threshold and the REC penalty price, there is insufficient overall generation investment to meet the reliability standard in some regions.

Importantly, given that these outcomes are not desirable our forecast wholesale prices should be treated as illustrative of what would happen given our modelling assumptions, rather than as forecasts of likely future prices. This is because we would expect some market changes or other mechanism to be instituted in order to ensure that the reliability standard as a minimum is satisfied. Further analysis of unserved energy was not a key focus of the work and detailed analysis would be required to confirm and quantify the broad conclusion. Incentives to encourage sufficient economic generation investment could be created through a number of approaches, including (amongst others):

- introducing a formal price on carbon, which increases wholesale market prices and so increases the profitability of renewable generation thereby lowering the need for gas generation investment to satisfy demand;
- increasing the market price cap and cumulative price threshold, thereby allowing revenues for new investment generation to be higher and sufficient to encourage profitable new entry; and
- increasing the penalty price paid if insufficient RECs are purchased by retailers, to improve the profitability of renewable generation investment.

While we have not systematically investigated these options, we observe that:

- including a carbon price in line with our assumptions in the carbon scenario that we considered, results in the LRET being satisfied although the reliability standard remains unsatisfied later in the study period; and
- the penalty price would need to increase to approximately $75 to $80 to bring forward sufficient additional renewable generation to satisfy the LRET.

Our results for the SWIS suggest that a combination of existing and committed renewable plant will satisfy the assumed allocated LRET requirement. Unlike the NEM results, there are no equivalent concerns for unserved energy in the SWIS given the design of the market and more directly managed reserve margin.

The following sections present the modelling results in greater detail.

4.2. Forecast spot market prices

4.2.1. National Electricity Market and South West Interconnected System results

Figures 4.1 and 4.2 set out the forecast electricity wholesale market prices in the NEM for the period FY2011 to FY2030 in real terms based on 2010/11 dollars, for both the reference case and the reference case with the LRET target enforced, respectively. In each case we ensured investment in thermal plant was profitable (ie, that the ratio of revenue to costs was 1.0 or greater). In a number of cases this meant the unserved energy standard was exceeded for a number of years in a number of regions. As noted earlier, examination of unserved energy was not a key objective of the study. Our conclusion that the standard may be exceeded should therefore be considered a trigger for closer examination rather than a final conclusion.

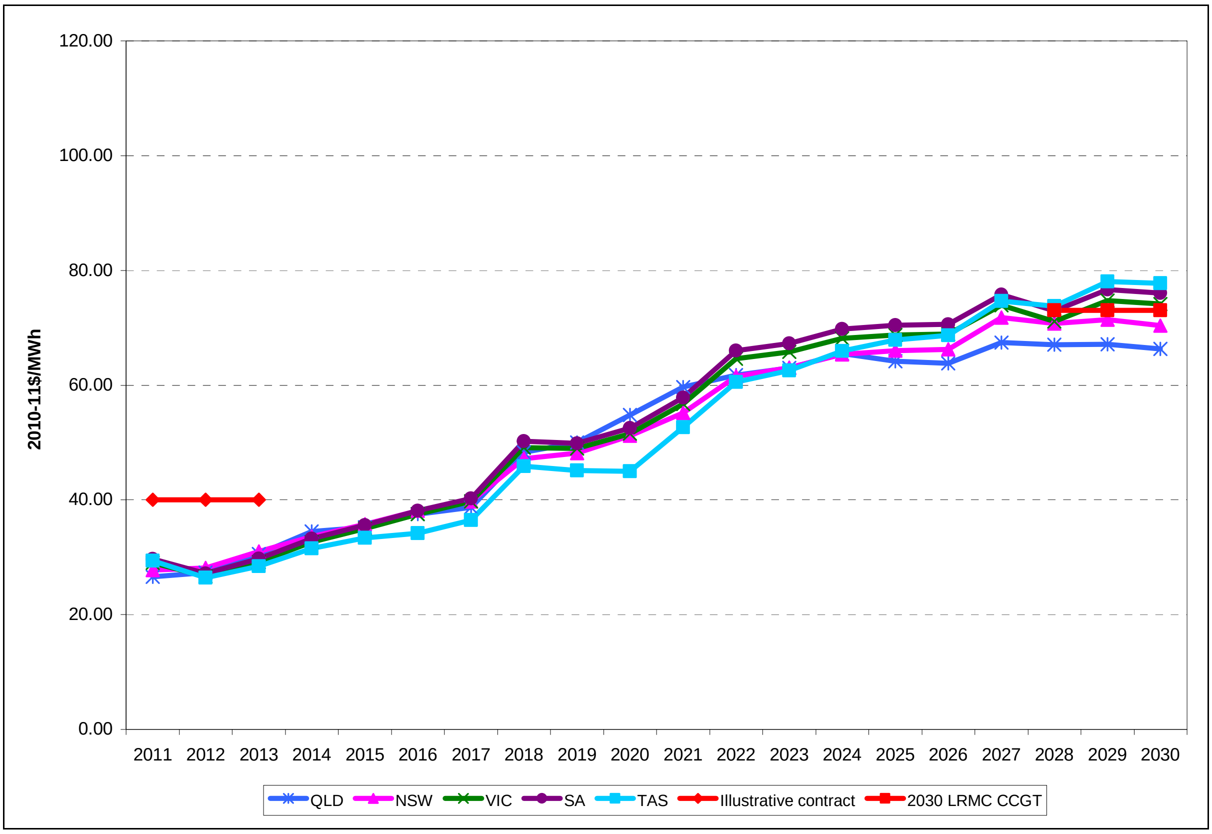
Our results indicate that by FY2030, NEM prices are expected to align with the new entrant cost of a CCGT plant as we would expect. In the first few years, we have not attempted to account for contract prices and the results highlight that the fundamental analysis of the marginal price resulting from the modelling falls below the published contract price.

Higher prices in the initial years would tend to advance the timing of additional OCGT entry at the expense of less entry later. This would likely reduce the unserved energy in the early years below the level currently seen in the results. However, unserved energy in the early years is already below the standard.

In practice, contract prices are likely to dominate wholesale electricity purchase costs in the near term and so we have shown an illustrative contract price on the chart for reference. The anticipated growth in prices is driven by a combination of factors, including anticipated increases in gas fuel prices over the period, and the cost of commercial new investment requirements from around FY2020.

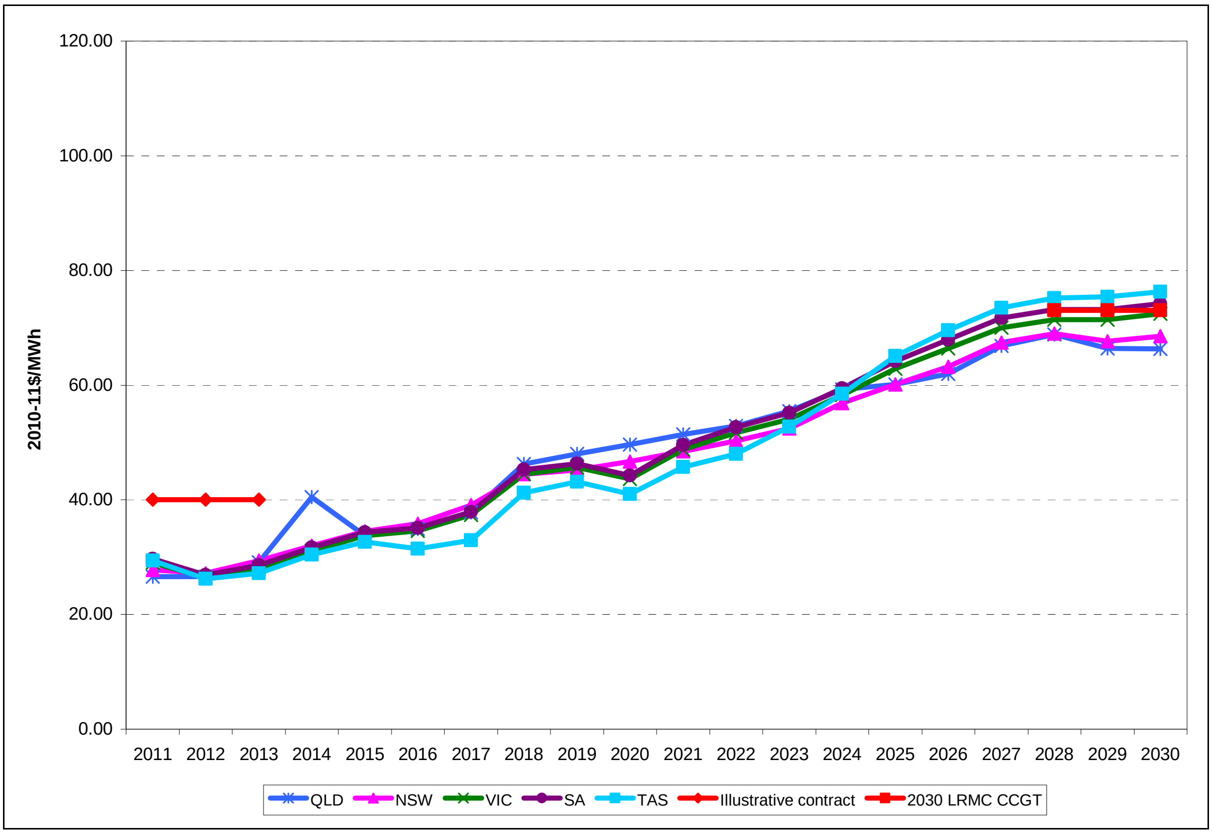
The differences in prices between the two LRET cases examined highlight that prices are lower where renewable plant has been forced in to meet the LRET target (Figure 4.2) compared to the case where only economically viable renewable investments are made (Figure 4.1). The difference in the NEM wholesale price represents the significantly higher renewable plant capacity installed to satisfy the LRET by FY2020, compared to the capacity installed when the penalty price is paid instead of achieving the LRET (see section 4.4 for a discussion on new investment). By FY2020 the difference in price between a case where sufficient new investment entered to allow the LRET to be met and a case where only economically viable renewable investments were made is approximately $5/MWh.

Figure 4.1: NEM Price Forecast - Reference Case



Note: Data represents financial years (eg, 2011 is 2011/12)

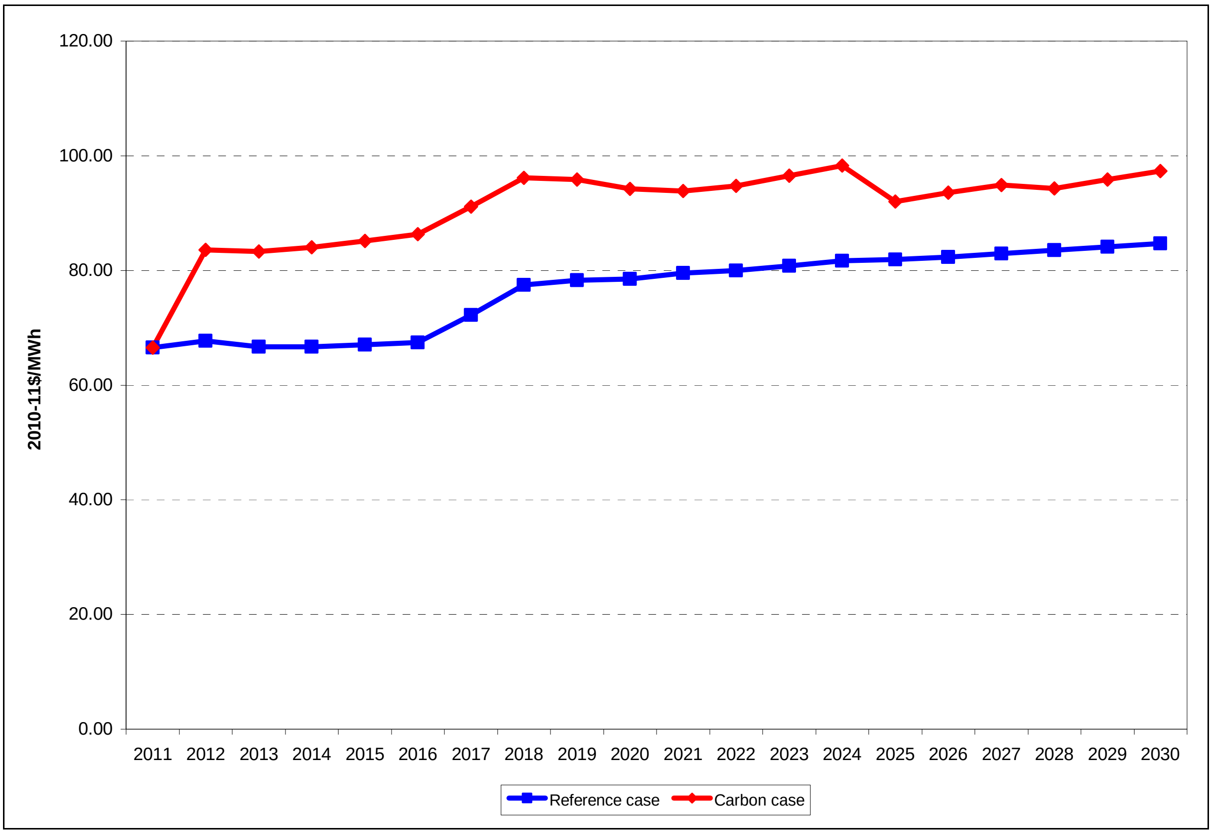
Figure 4.2: NEM Price Forecast - Reference Case – LRET Enforced



Note: Data represents financial years (eg, 2011 is 2011/12)

In contrast to the NEM, prices in the SWIS are forecast to be comparatively flatter, increasing from approximately $67/MWh in FY2011 to $79/MWh in FY2020. Prices in the SWIS increase between FY2016 and FY2018 because of the anticipated expiry of existing gas contracts and replacement with higher priced fuel.

Figure 4.3: WEM Price Forecast - Reference Case

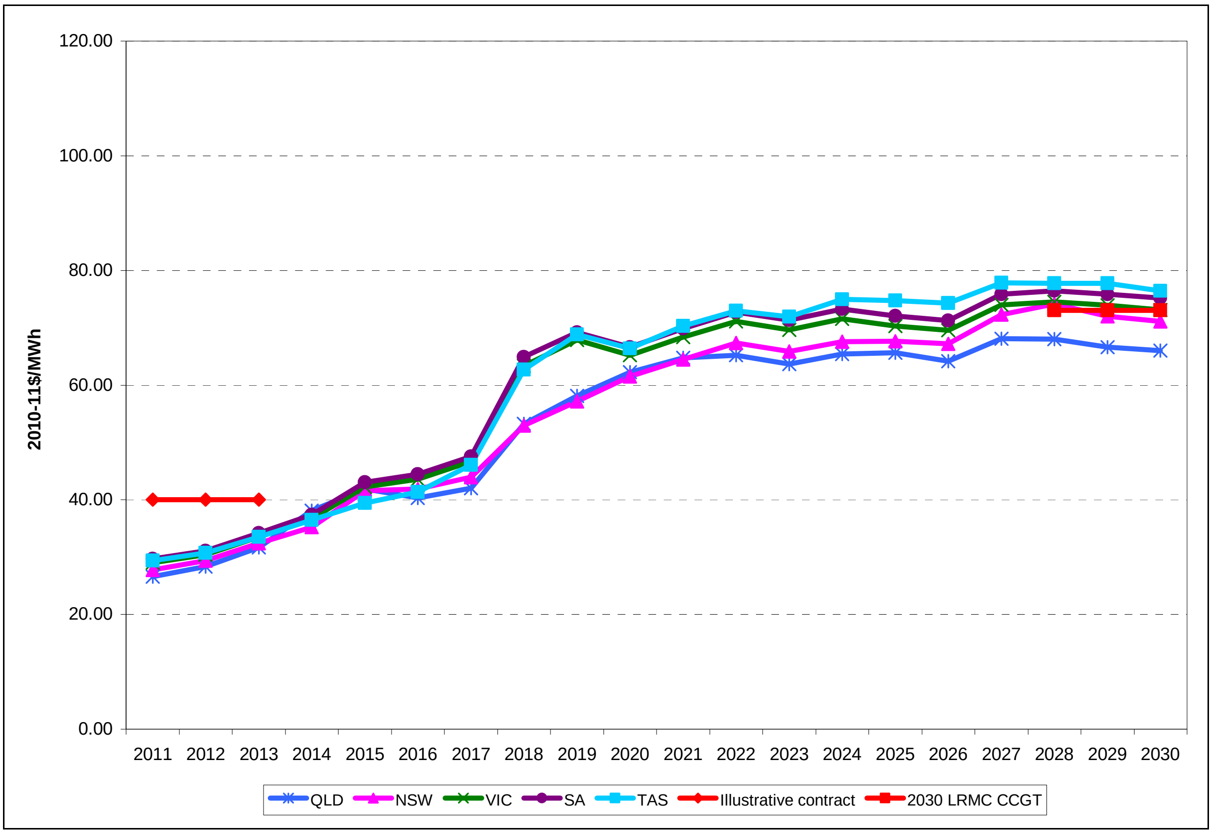


Note: Data represents financial years (eg, 2011 is 2011/12)

4.2.1.1. Impact of the LRET

The counterfactual results demonstrate the influence of the LRET on market prices in the NEM. Specifically, where no LRET is present, NEM prices are expected to be higher meaning that the effect of the LRET is to dampen wholesale market prices.

Figure 4.4: NEM Price Forecast – Counterfactual Case



Note: Data represents financial years (eg, 2011 is 2011/12)

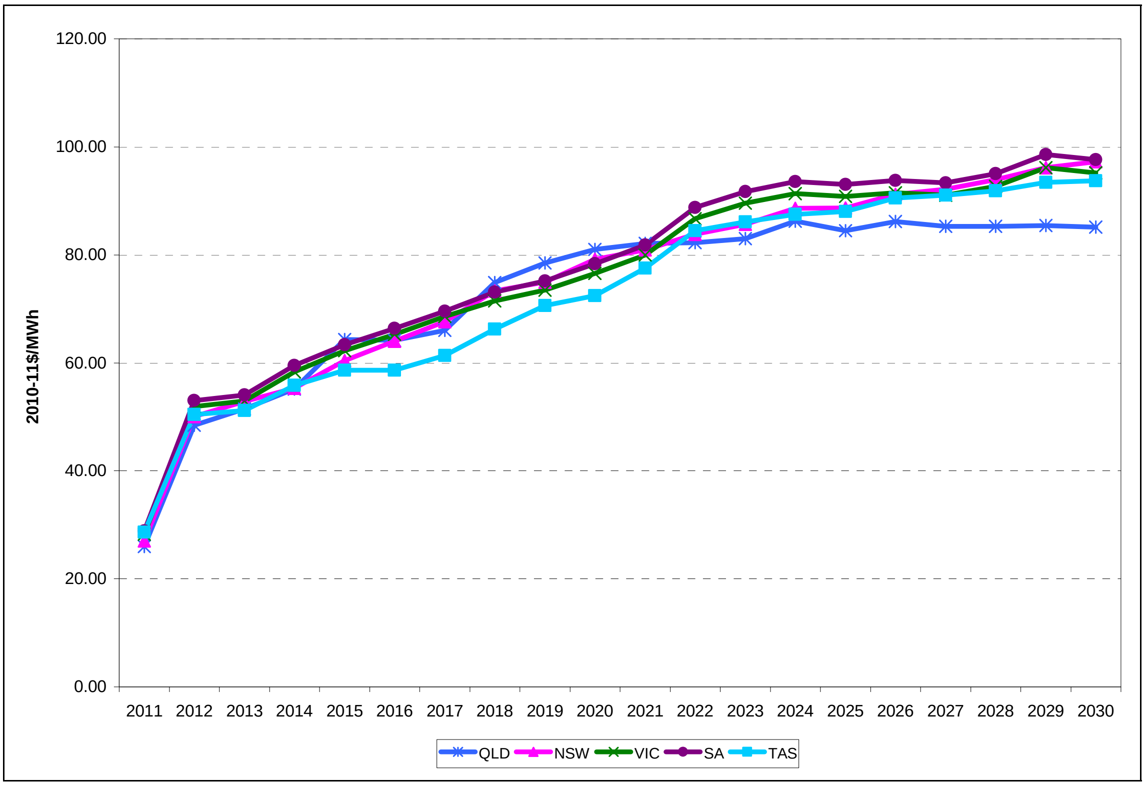
The size of this dampening effect in the NEM is greatest as the LRET FY2020 requirement approaches its peak contribution. For the modelled case where the LRET is assumed to be fully met, the difference is $18/MWh. The difference is lower (approximately $13/MWh) when only profitable renewable investment is allowed.

Importantly, while the forecast wholesale prices are lower than might otherwise have been the case in the absence of the LRET, the overall cost of electricity generation would be higher with the LRET. This is because the wholesale electricity cost is the sum of wholesale market prices, and the cost of renewable energy certificates.

4.2.1.2. Impact of including a price for carbon

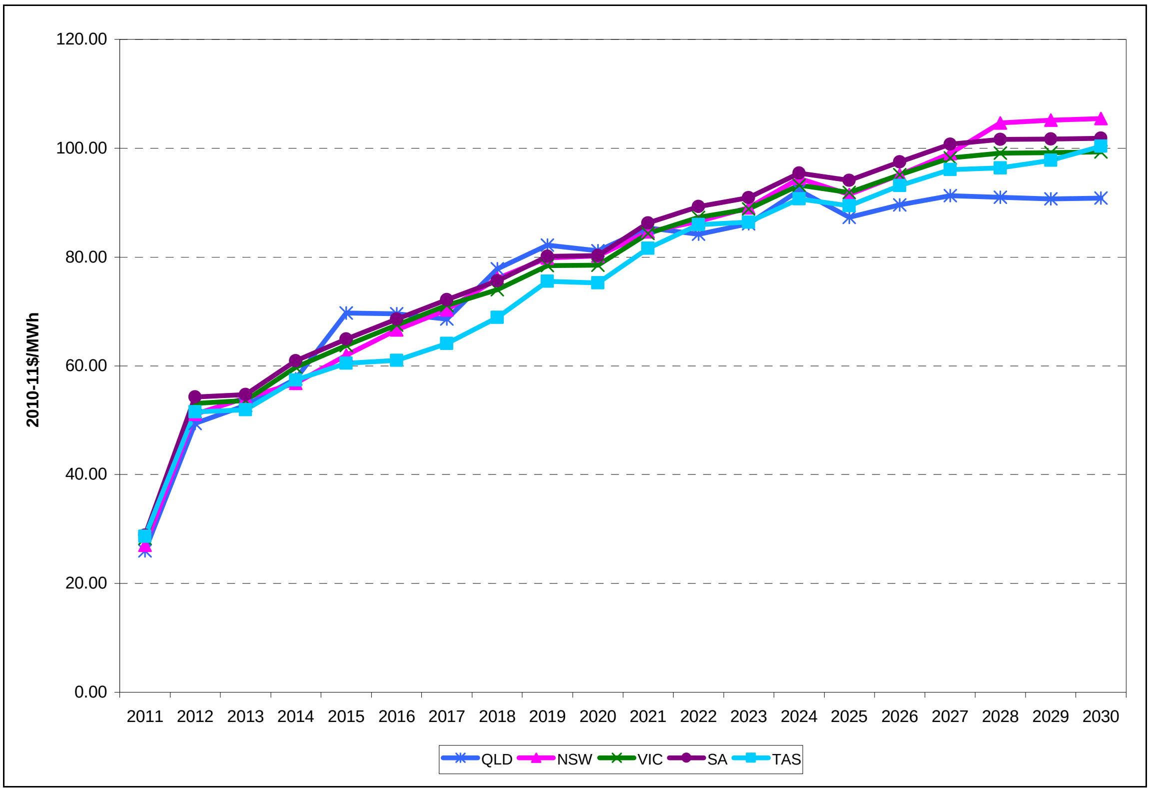
Figure 4.5 sets out the NEM price forecast under Carbon Price Scenario 1, whereas Figure 4.6 sets out the NEM price forecast under Carbon Price Scenario 2. Prices in both of these scenarios are higher than under the reference case, reflecting the impact of the carbon costs into wholesale market prices. By FY2020, the NEM price in both of these cases is around $80/MWh in each region.

Figure 4.5: NEM Price Forecast – Carbon Price Scenario 1



Note: Data represents financial years (eg, 2011 is 2011/12)

Figure 4.6: NEM Price Forecast – Carbon Price Case Scenario 2



Note: Data represents financial years (eg, 2011 is 2011/12)

Our results have been expressed in terms of the impact of the LRET on spot market prices. However, the wholesale cost of electricity to retailers is represented by a combination of the wholesale market price (which itself is likely reflected by contract prices), and the cost of complying with the LRET (ie, the cost of RECs or the payment of the penalty price). The consistently lower price in Queensland at the end of the study horizon suggests there is likely to be benefit in augmenting interconnection between New South Wales and Queensland from around 2025. That said, we did not examine the need for interconnection augmentation further.

In addition, the results reflect the start of the transition to a lower carbon intensive technology mix. A carbon price initially increases the wholesale price but does not begin to change the relative dispatch of coal and gas until the variable cost of production from coal plant exceeds the variable cost of production from gas. From this point, coal production falls and gas production increases. As demand grows, gas is the preferred technology for new investment, except where lower emission technologies are economic and available. As coal plant utilisation falls, units spend more time close to minimum operating levels, which range between around 40 and 60 per cent of capacity. Eventually the coal units shutdown during periods of low demand, which can be as short as overnight or as long as seasonal operation, until eventually they become uneconomic and are entirely withdrawn from service.

While coal units are operating at minimum levels they are not marginal and so the price falls to the marginal plant with lower prices, which at times can be close to zero or possibly negative. This outcome has already been seen in the South Australian region when wind production is high. When coal units are withdrawn from service new plant enters and the price progressively trends towards the new long-run cost of these new entrants (with a number of intermediate peaks and troughs throughout the transition). The timing and size of these peaks and troughs depend on a number of case-specific factors, including assumptions about commodity prices, new technology costs and availability, unit cycling and the trigger for retirement. For example, a higher gas price increases the wholesale price and so leaves coal plant profitable for longer, which delays retirement.

In the alternative carbon price schedules, the carbon price is higher in every year, and emissions and gas use are little different until 2020. By 2015 CCGT begins to displace black coal (brown coal has already been displaced in the base carbon schedule

4.2.2. Darwin-Katherine Integrated System

The Darwin-Katherine interconnected system (DKIS) is operated by the Power and Water Corporation (P&WC), which owns and operates most of the installed generation capacity and also purchases electricity under contract. Generation capacity is dominated by OCGT plants, running on natural gas. The P&WC is in the process of augmenting its portfolio and has long term contracts for the purchase of gas.

Our approach to examining wholesale price implications of the LRET in the DKIS has been based on the new entrant costs of an OCGT plant operating at relatively high utilisation.

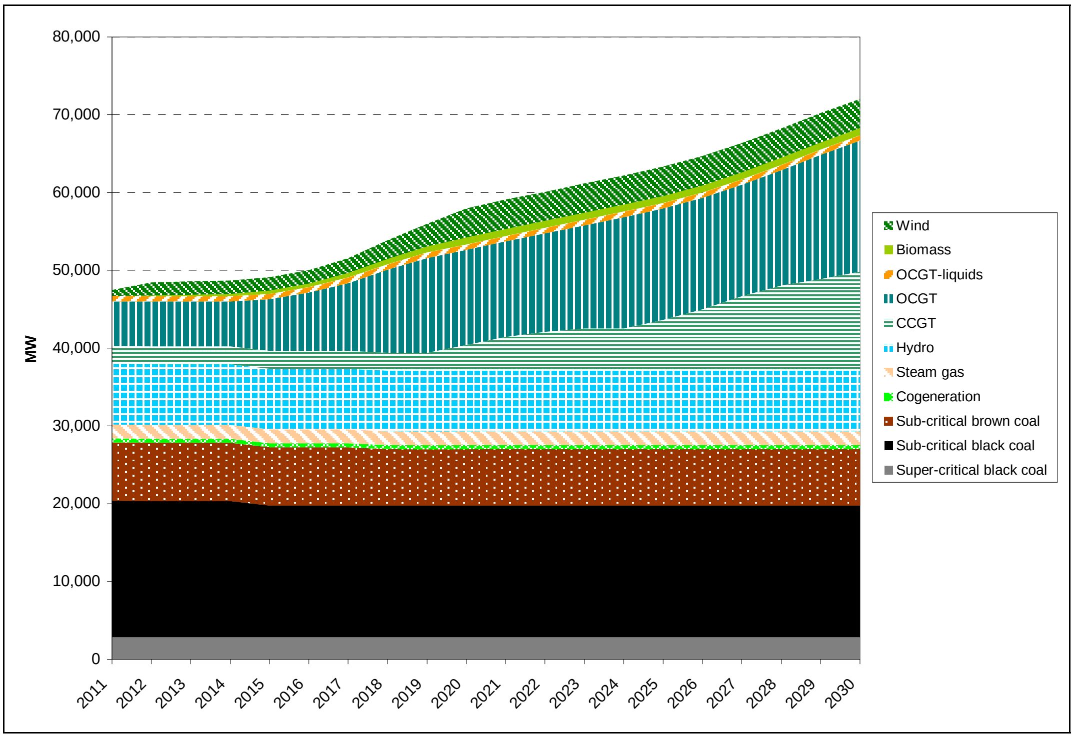
Based on data prepared for the AEMO/DRET[13] the wholesale cost of generation in the DKIS will be relatively flat in real terms between $70/MWh and $75/MWh over the period to FY2030. We would expect some fluctuations in this range depending on the timing of progressive augmentation of the generation portfolio by P&WC, as foreshadowed in the P&WC annual report and a recent review by the NT Utilities Commission.[14]

4.3. Profile of generation investment

The following figures show the generation technology mix for the NEM in the reference case (ie, Figure 4.7) and for the situation where the LRET is forced to be met (ie, Figure 4.8).

The penalty price places an effective cap on the price of RECs and so caps the revenue that can be earned by renewable generation investment. This is because customers (ie, retailers) are expected to prefer to pay the penalty rather than invest in renewable plant where the effective cost is higher than the penalty price. As a consequence, when only profitable renewable investment is considered, the amount of additional renewable generation capacity installed by FY2020 over current levels is 4,200MW – Figure 4.7. The renewable generation in this case is mostly wind, with the remainder being biomass generation.

Figure 4.7: NEM Scheduled and Semi-Scheduled Installed Capacity - Reference Case



Note: Data represents financial years (eg, 2011 is 2011/12)

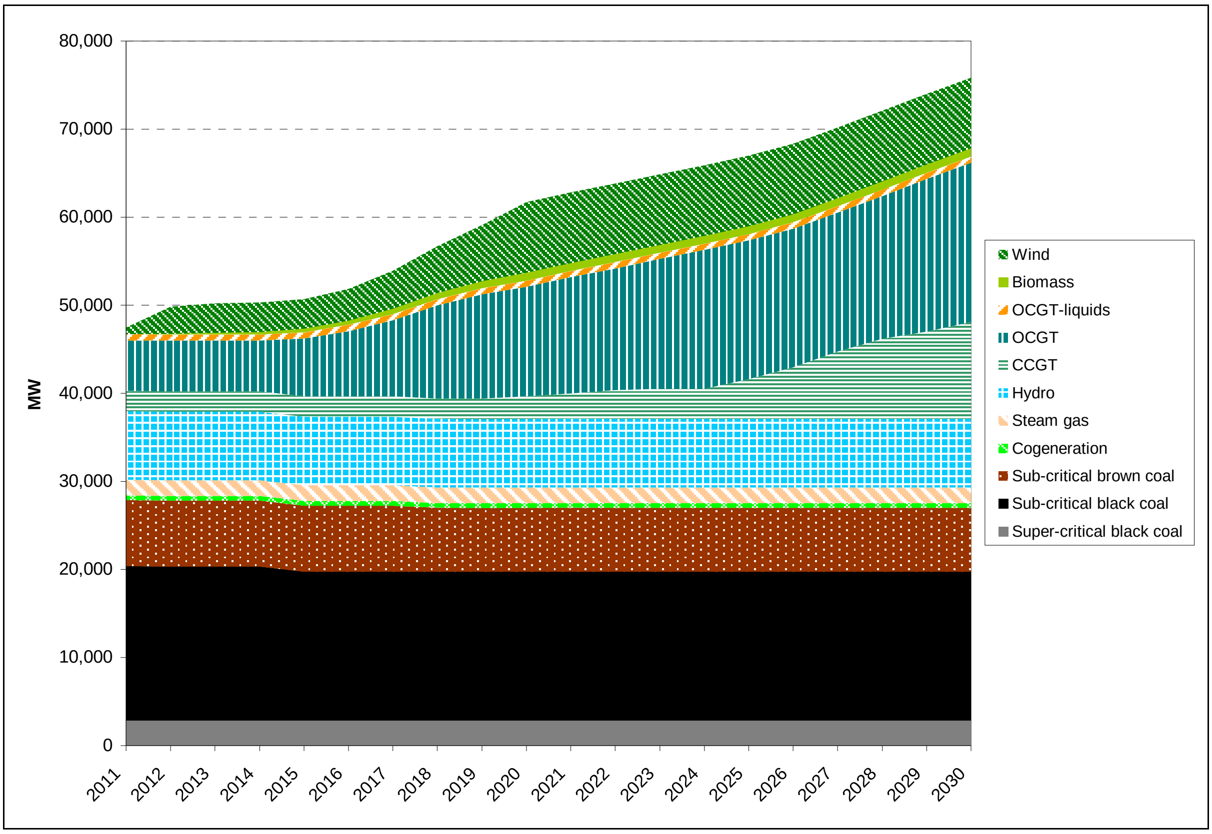
13 Australian Energy Market Operator, (2010), National Transmission Network Development Plan Modelling Assumptions: Supply Input Spreadsheets, 23 August.

14 Power and Water Corporation, Annual Report 2010. www. Powerwater.com.au and Utilities Commission, Power System Review, March 2011, www.utilicom.nt.gov.au

Open cycle gas plant is economic during the early years with 7,000MW and 1,300MW additional CCGT capacity installed across NEM regions by FY2020 in the case with only economically viable renewable plant. After FY2020, CCGT plant continues to grow and by FY2030 a further 4,600MW of open cycle and 9,000MW of CCGT plant enter. However, we note that had coal plant been an option it is likely that it would have entered in place of at least some of the CCGT although we did not examine this matter in the modelling.

Since a significant amount of the plant that enters to meet the LRET is intermittent wind capacity the nameplate capacity of generation is greater than when the LRET is not met – ie, it is not a one for one substitution of generating capacity. In the NEM we have assumed wind will contribute only 3 per cent of installed capacity over the peak periods. An additional 8,500MW of additional (nameplate) renewable plant would enter by FY2020 when the model is forced to meet the LRET.

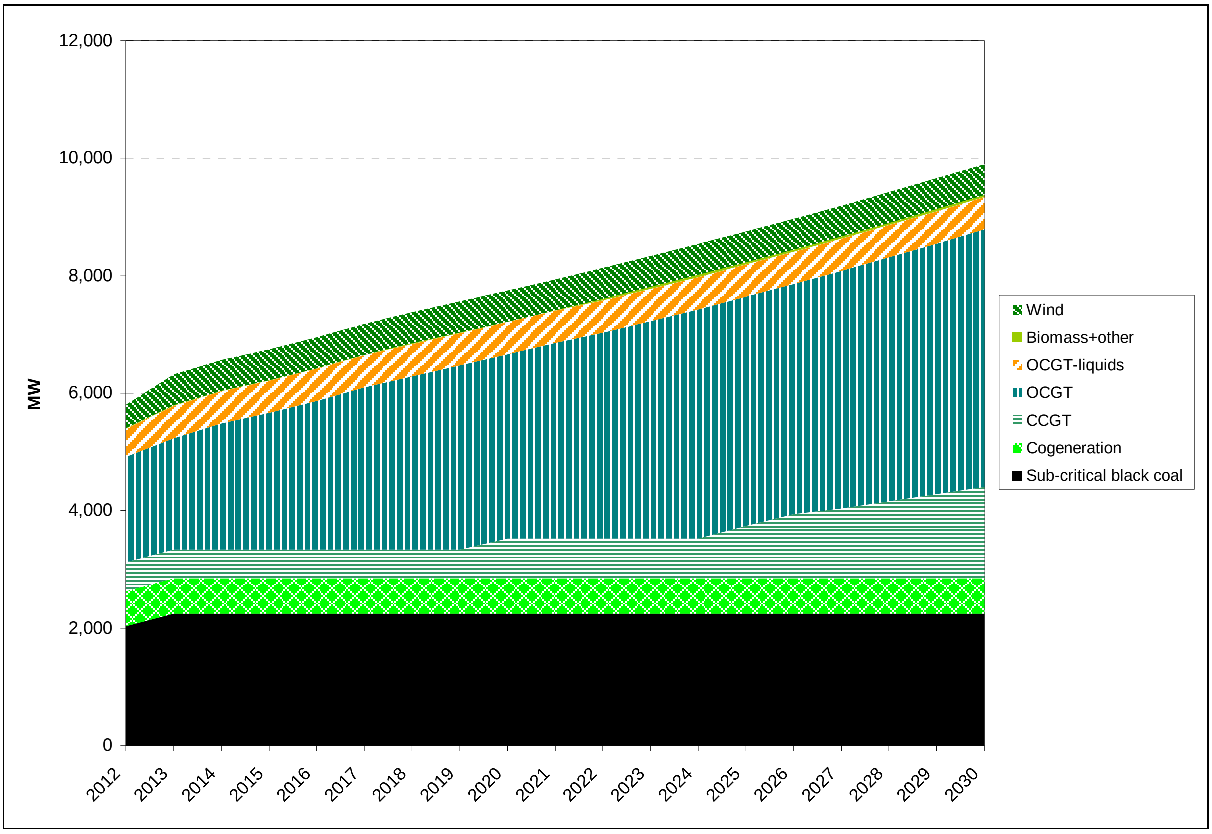
Figure 4.8: NEM Scheduled and Semi-Scheduled Installed Capacity - Reference Case - LRET Enforced



Note: Data represents financial years (eg, 2011 is 2011/12)

In the SWIS, new investment in generation capacity is primarily wind and OCGT prior to FY2020, with CCGT plant appearing from FY2020 – Figure 4.9. The overall level of generation capacity investment is driven by the capacity reserve margin under the market rules. 180MW of CCGT enters before FY2020 and a further 900MW enters by FY2030. 1,200MW of OCGT enters by FY2020 and a further 1,200MW by FY2030.

Figure 4.9: SWIS Scheduled and Semi-Scheduled Installed Capacity – Reference Case



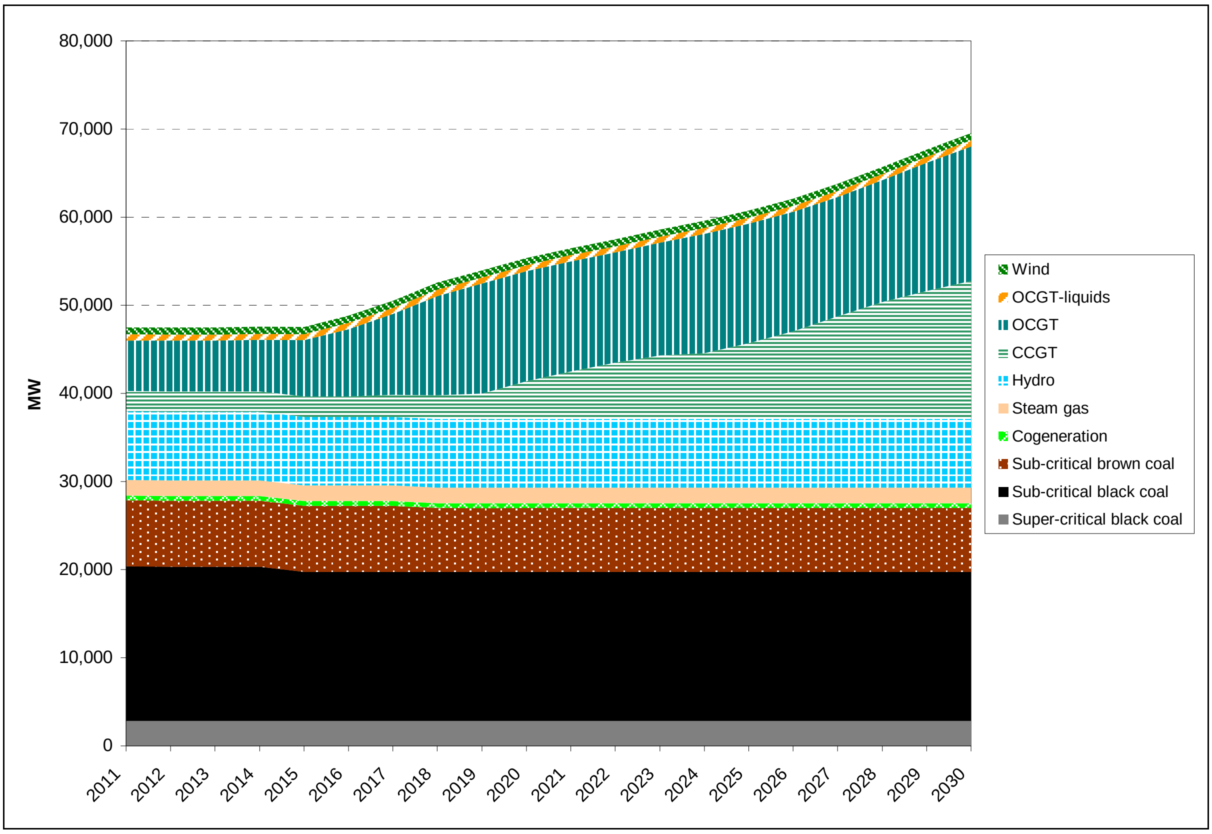
Note: Data represents financial years (eg, 2011 is 2011/12)

Across all of the scenarios, the LRET requirements are principally met by wind and biomass. This result is different from some of the outcomes presented by others particularly where resource limits on the amount of wind that can be installed results in other technologies, primarily geothermal, being brought into the mix at higher cost. This observation highlights the importance of the input assumptions about technology cost, the availability of resources, and any relevant limits to the rate at which a new technology can be introduced, for the price outcomes. If resource limits had constrained the wind capacity installed in our case, it is likely that we would have found that the shortfall on meeting the LRET target would have been greater, as the alternative renewable investments such as geothermal would be more expensive and the LRET penalty price have restricted investment further.

4.4. Impact of the LRET and carbon price on the profile of investment

Figure 4.10 sets out the profile of investment for the counterfactual (without LRET) for the NEM.

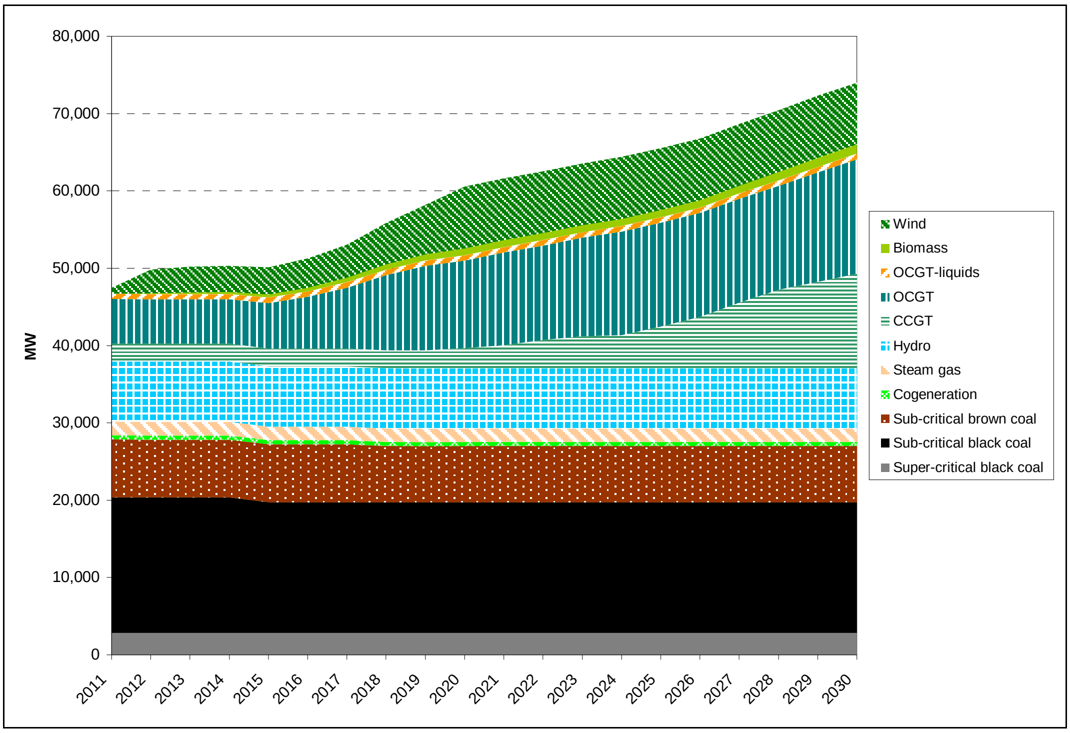
Figure 4.10: NEM Scheduled and Semi-Scheduled Installed Capacity - Counterfactual



Note: Data represents financial years (eg, 2011 is 2011/12)

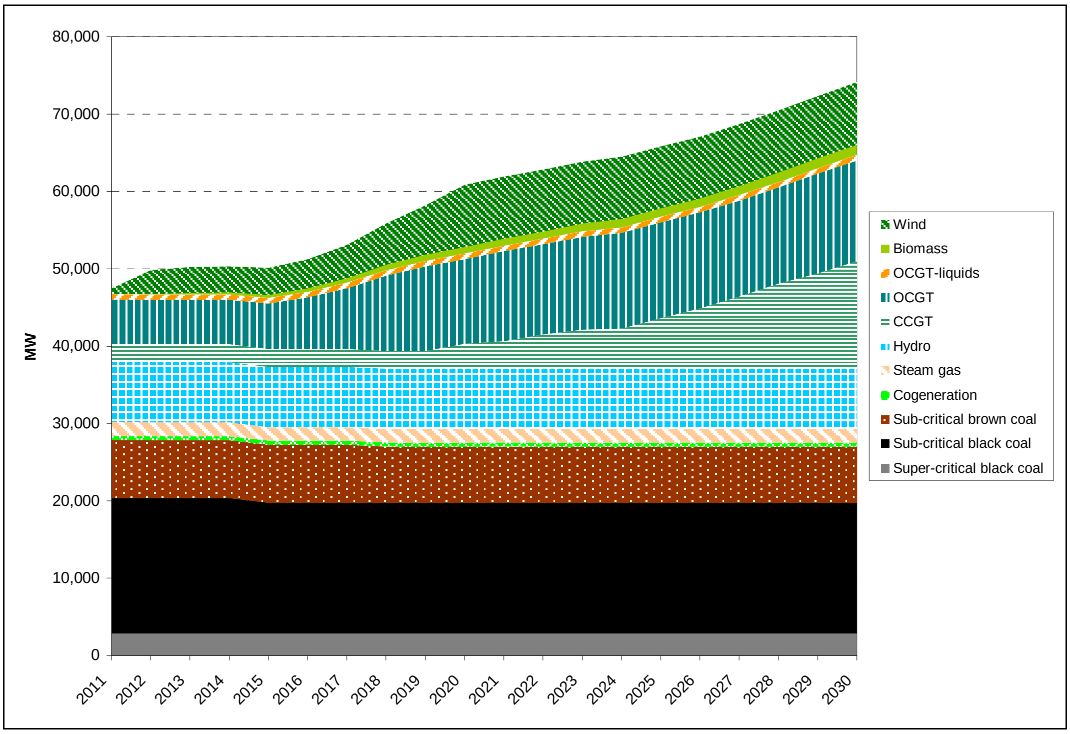
Figure 4.11 to Figure 4.13 sets out the profile of investment under the carbon price trajectories described in section 3 for the NEM and WEM, respectively.

Figure 4.11: NEM Scheduled and Semi-Scheduled Installed Capacity – Carbon Price Scenario 1



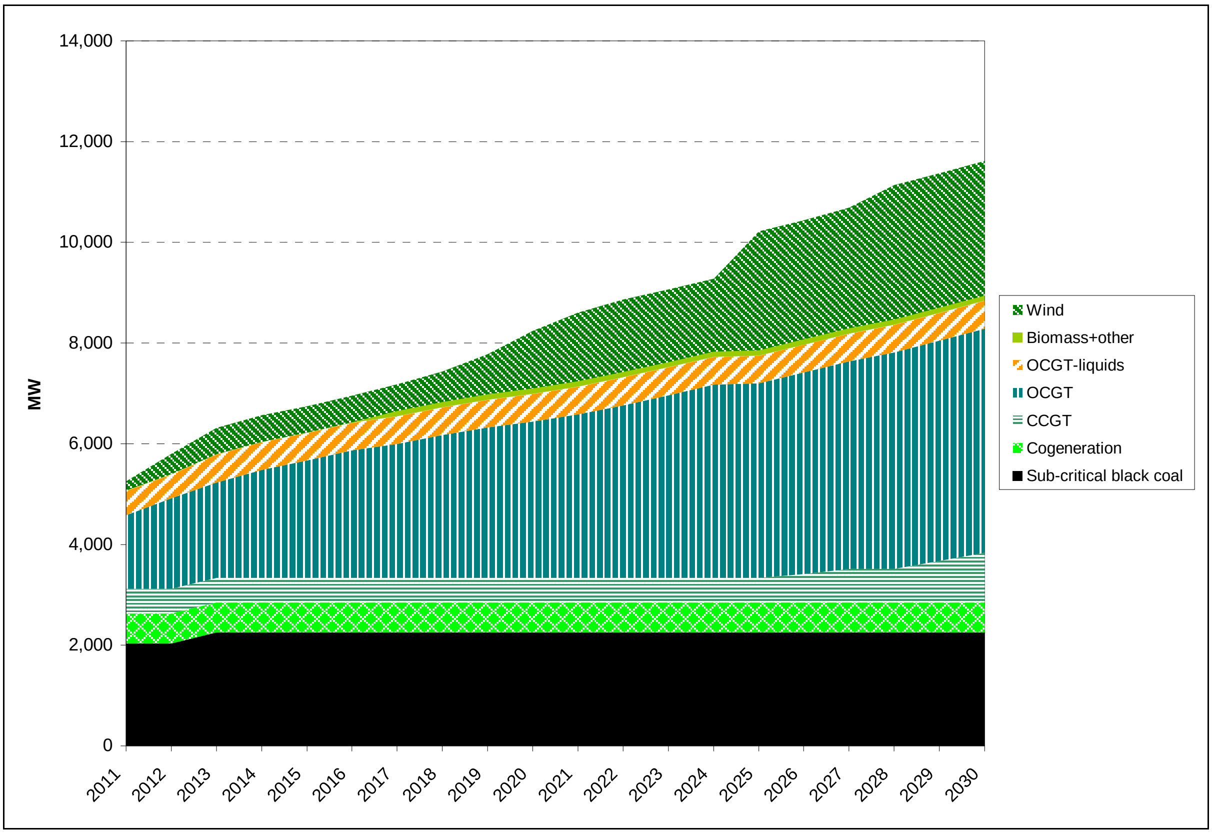
Note: Data represents financial years (eg, 2011 is 2011/12)

Figure 4.12: NEM Scheduled and Semi-Scheduled Installed Capacity – Carbon Price Scenario 2



Note: Data represents financial years (eg, 2011 is 2011/12)

Figure 4.13: SWIS Scheduled and Semi-Scheduled Installed Capacity – Carbon Case



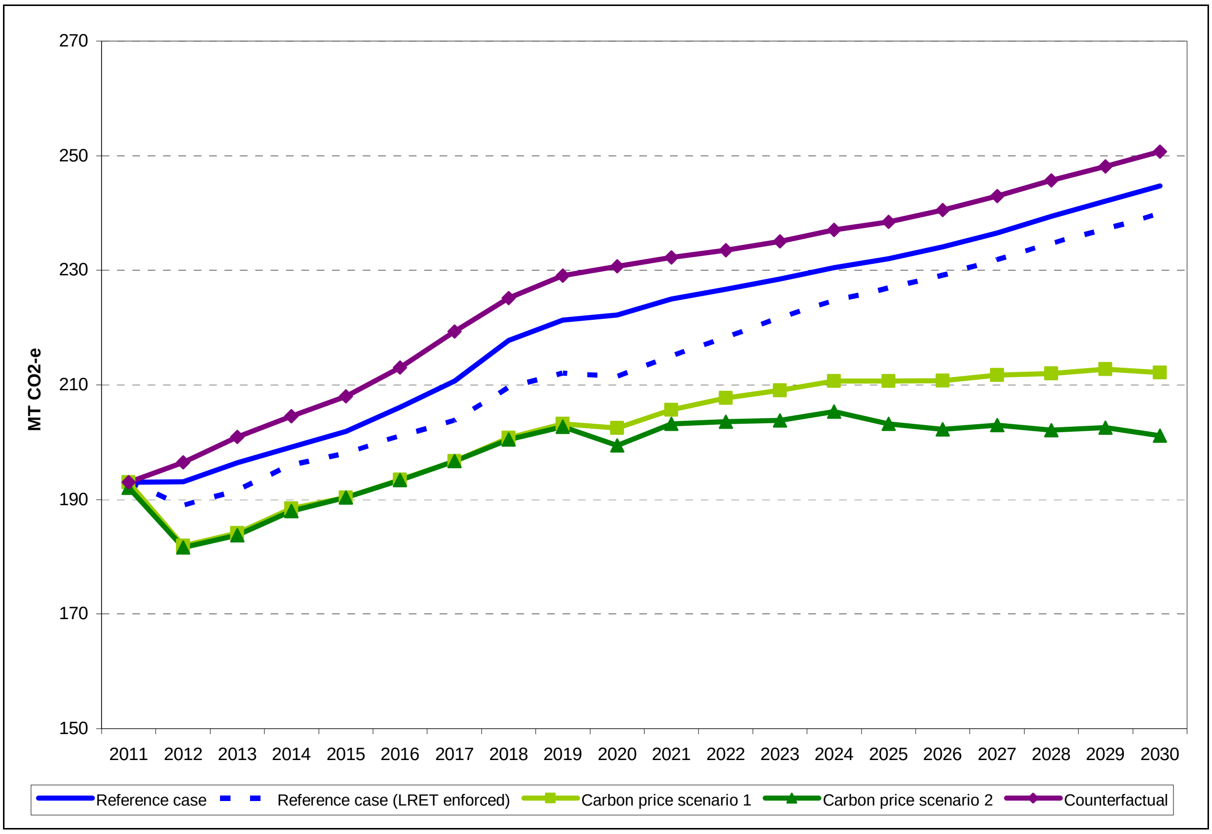
Note: Data represents financial years (eg, 2011 is 2011/12)

4.5. Emissions from electricity generation

The resultant emissions from electricity generation are set out in Figure 4.14 for each of the cases and where the restriction on the reference case to install only profitable renewable plant is removed and the LRET target for the NEM is met in full.

It is notable that emissions continue to rise under all scenarios including the carbon case, although no retirement of existing coal plant has been considered. Preliminary analysis of the profitability of coal plants under these scenarios suggests that existing plants are approaching a breakeven position by the end of the study in the carbon case. Retirement has been assessed by examining the operating profitability of existing plant formed from the ratio of: Market revenue: (operating cost + fuel related expenses + carbon related expenses). Ratios of 1 or greater are regarded as profitable.

Figure 4.14: Emissions from Electricity Generation - NEM



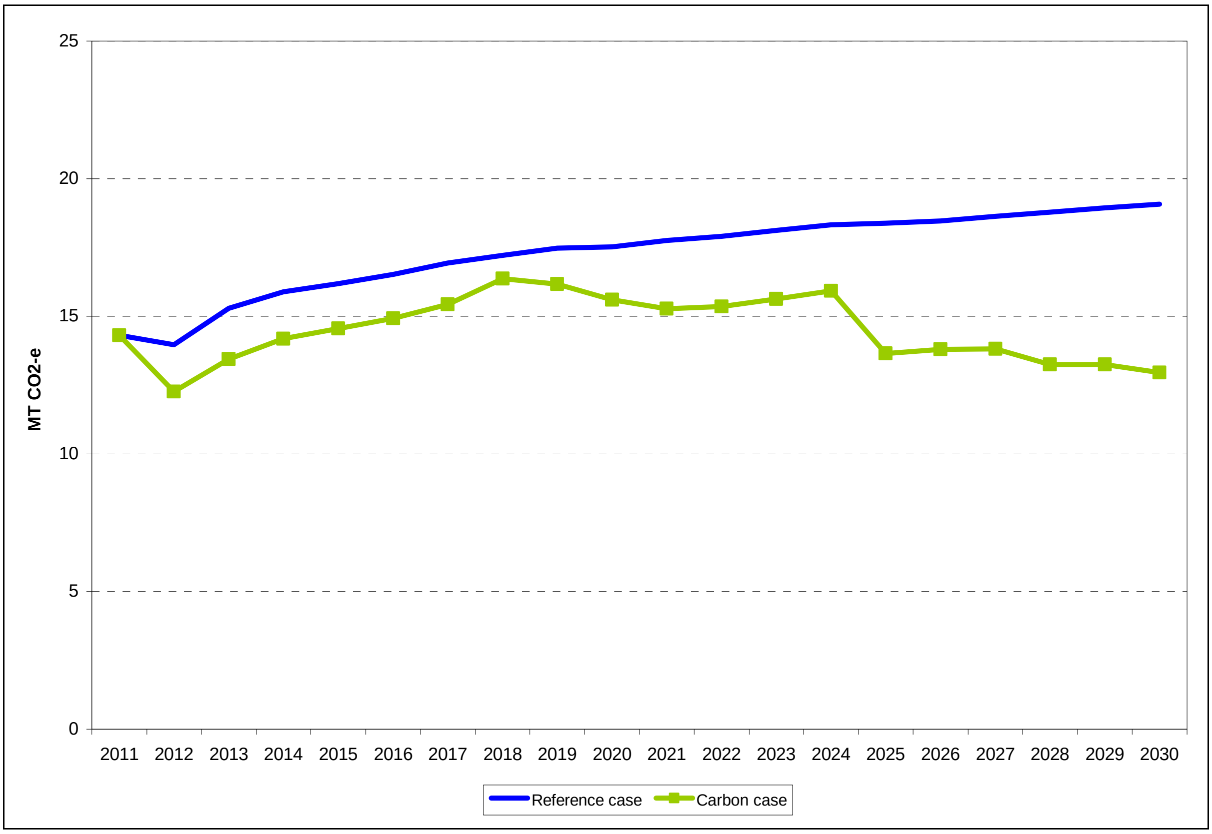
Note: Data represents financial years (eg, 2011 is 2011/12)

Notably, by FY2020 emissions in the reference case rise by about 15 per cent compared to FY2011 levels. With the assumed carbon prices, the increase is lower (between 3 to 5 per cent), while it is higher if there is no LRET (approximately 20 per cent). The effect of the LRET (relative to the counterfactual) is to decrease emissions in the NEM by approximately 5 per cent.

The carbon case has lower emissions and also has lower demand reflecting expected responsiveness of demand to the higher prices in this case. The full LRET target is expected to be met in the carbon case and this also contributes to the lower level of emissions. Notably, there would be relatively low REC prices (ie, $10/MWh in $2010/11) in some years.

Figure 4.15 sets out the resultant emissions from electricity generation in the WEM for the reference and carbon cases.

Figure 4.15: Emissions from Electricity Generation - WEM



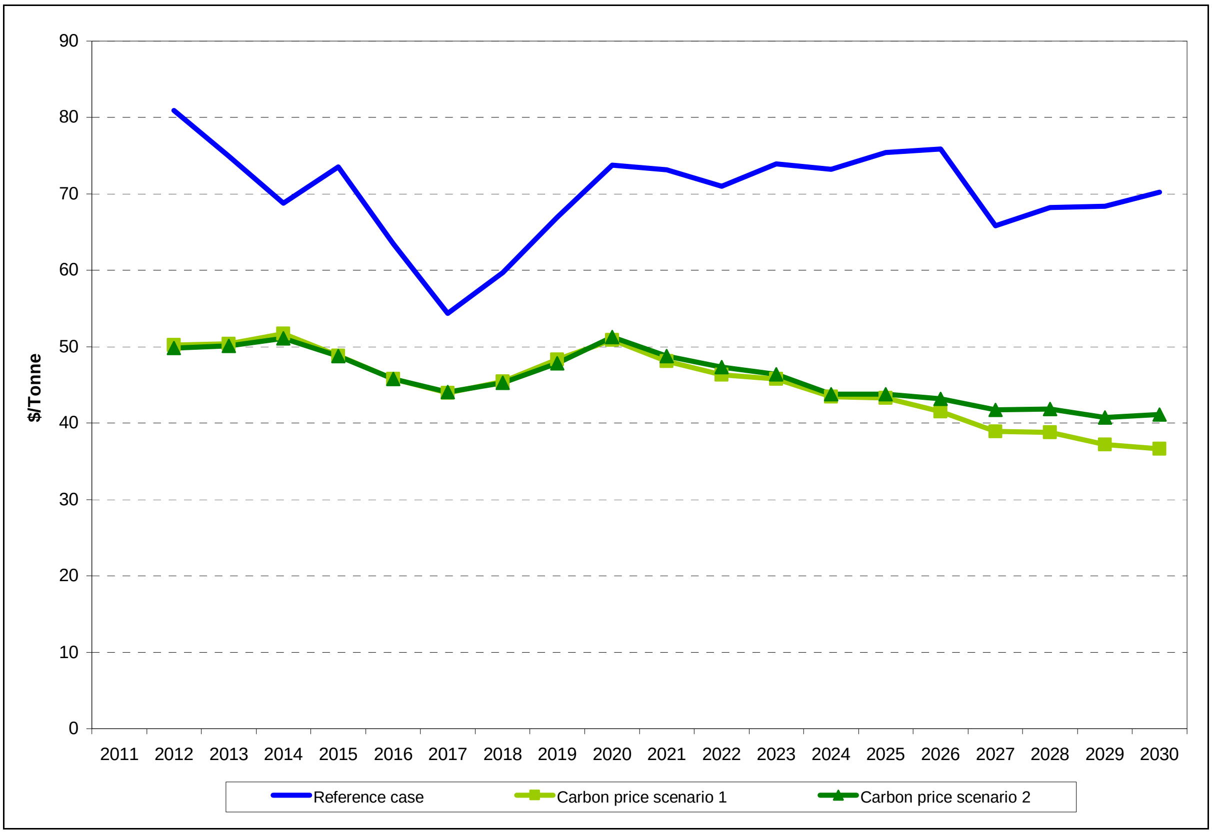
Note: Data represents financial years (eg, 2011 is 2011/12)

The reference case naturally has the highest emissions as it has no carbon price to reduce the dispatch of high emission plant. Emissions in the reference case are 24 per cent higher in FY2020 compared with FY2011 emission levels.

Under the carbon price scenario, the increase in emissions by FY2020 is 9 per cent (compared to FY2011 emission levels).

Finally, the implied abatement costs for each reference case and carbon case (as compared to the counterfactual) are set out in Figure 4.16.

Figure 4.16: Abatement costs



Note: Data represents financial years (eg, 2011 is 2011/12)

The abatement costs represent the cost of the LRET to industry. Importantly, the abatement costs in the carbon case are affected by both more expensive plant and lower demand. These have counteracting influences on the cost of abatement, which results in the abatement costs not aligning with carbon prices. However, if demand didn't decrease in the carbon case, the abatement costs would align with carbon prices.

The abatement costs represent the incremental operating and capital costs for the industry to reduce emissions in the reference and carbon cases compared to the counterfactual case. The cost of abatement cost is calculated as the additional annualised operating and capital costs relative to the counterfactual divided by the change in emissions in each case.[15]

In the carbon case, the cost of abatement trends downward during the period of the study but would be expected to track closer to the carbon price in the long-term. However, it is also affected by the reduced demand assumed for the carbon case compared to the counterfactual case. In addition, abatement costs are influenced greatly by the assumptions used for each case in each study. Notably, less abatement occurs in the reference case, which results in a higher and more volatile cost per tonne of abatement relative to the carbon case.

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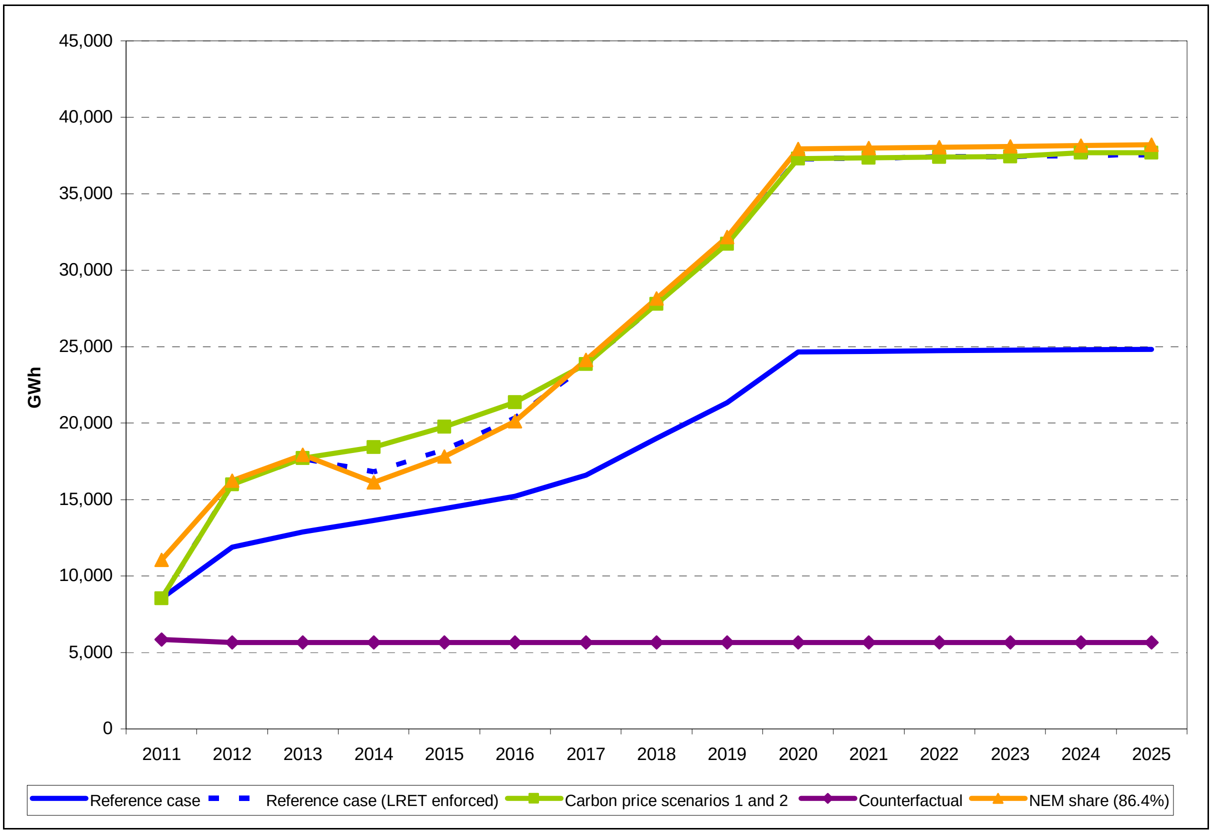
15 Notably, operating costs exclude the cost of carbon taxes/permits but includes all other taxes and royalties paid by the industry to operate.

4.6. Scope to satisfy the LRET by FY2020

The results highlight that the LRET is not satisfied by FY2020 under the reference case. Indeed the shortfall is between 35 and 40 per cent of the target shown in Figure 4.17.

Figure 4.17: Proportion of Renewable Generation



Note: Data represents financial years (eg, 2011 is 2011/12)

The key reason for the shortfall is that it is more cost effective for retailers to pay the penalty price of $65/MWh than purchase RECs, given the price of renewable generation technologies, and anticipated limitations on its construction over the period to FY2020. The penalty price falls in real terms over time as it is set at $65/MWh but not indexed.

Figure 4.18 shows the tax effective level of support assuming a company tax rate of 30 per cent so that the support is equivalent to $92.86/MWh in FY2011 but falls in real terms after that time.[16]

The level of support required has been found by differencing the revenue a new renewable investment would make from the market price, and the revenue it would need to make to

[16] This penalty price was legislated in January 2011. However, all other aspects of our analysis are based on financial years. Therefore, we have assumed that the penalty price remains at $92.86 through June 2012 and then decreases in real terms each financial year by the rate of inflation. Notably, the tax effective penalty price is the maximum price companies would pay as some companies may be able to minimise their effective tax.

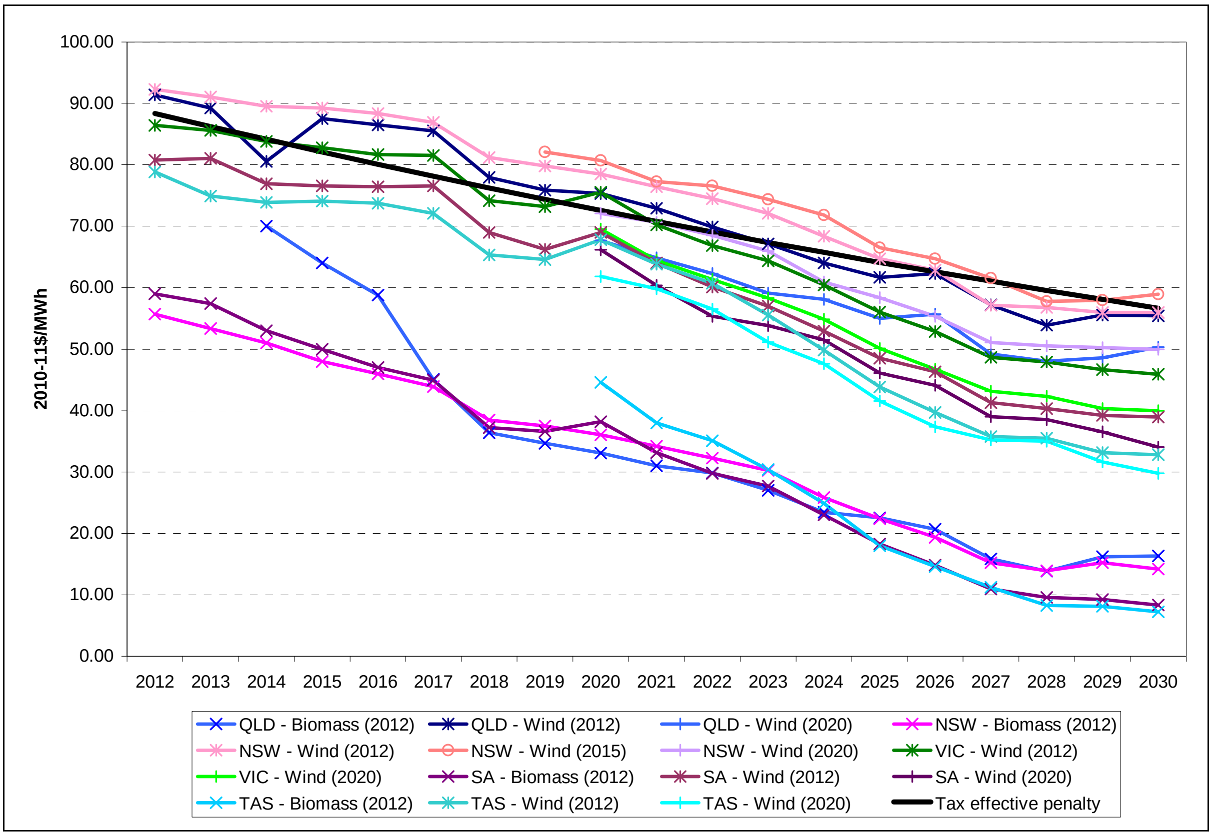
recover its annualised cost. In principle, this difference is the theoretical value of RECs up to the any relevant penalty price, where it is more economic for retailers to pay the penalty.

The level of support required in the case where the modelling has forced the entry of the full LRET requirement and as can be seen the support needed to make some of the investments profitable is greater than the penalty price. As a result the full LRET target is unlikely to be achieved. In the reference case LRET investment is restricted to only the investments that need support up to the tax effective penalty and as a result there is a shortfall in the order of 35 per cent on the FY2020 target in the NEM.

Results for the SWIS suggest the SWIS will be self-sufficient and just balance a pro rata share. The P&WC Annual Report indicates that it expects to meet its local obligations from local sources. We have not studied the remaining national systems and loads but these comprise only around 5 per cent of the national demand and any failure to meet the obligation or trading from other regions will have relatively limited impact on the national outcome.

As previously noted our analysis was designed to provide a high level view of the potential to achieve the LRET target. We did not attempt to forecast the future outcomes from the complex interactions between factors such as the banking of RECs, the impact of the transition to the split SRES and LRET design of the overall target and qualitative factors including the stop-start nature of project development and various policy changes that have occurred over recent years. The current overhang of RECs is creating a large surplus supply and materially suppressing the price of RECs but is not sustainable. In addition, we have not accounted for strategic behaviours by businesses that may be prepared to invest over and above the minimum required to demonstrate environmental credentials. That said the result highlights the key point that a material shortfall is possible.

Figure 4.18: Required REC Price to satisfy the LRET

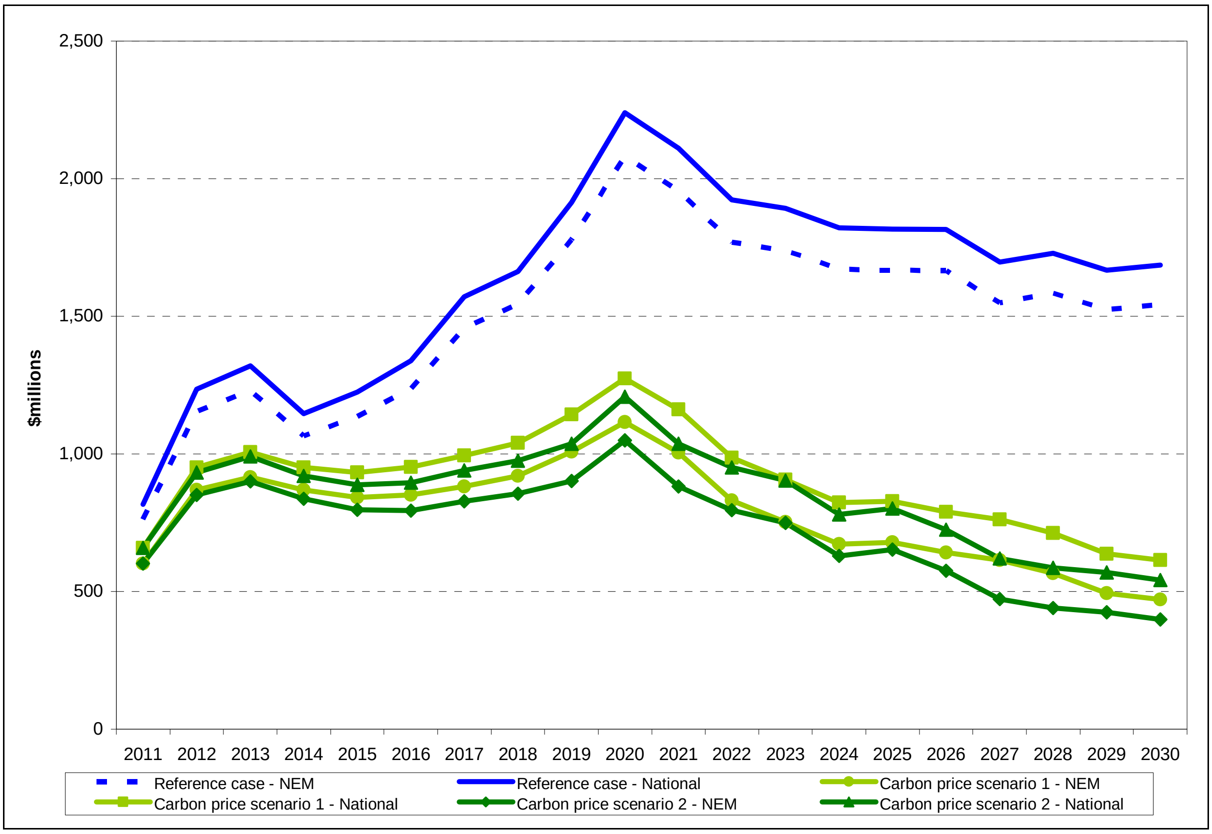


Note: Data represents financial years (eg, 2011 is 2011/12)

The results also indicate that for the LRET to have been achieved with profitable renewable generation investment, the penalty price would need to be increased to approximately $75 to $80/MWh assuming the penalty price is not indexed.

The implied annual compliance costs for LRET participants are set out in Figure 4.19.

Figure 4.19: NEM and National LRET Compliance Costs



Note: Data represents financial years (eg, 2011 is 2011/12)

LRET compliance costs have been calculated from the additional costs retailers incur to purchase RECs in each case, which is the cost for purchases from renewable plant that are greater than the cost of purchasing wholesale energy through the market at the prevailing price in each case. As noted above, the REC market has not been explicitly modelled. For the purposes of comparison we have assumed that the REC prices will align with first principles and can increase up to the effective penalty price.

Compliance costs shown are indicative as they are based on a number of assumptions about the costs for existing plant and costs for renewable plant that is not part of the NEM or the SWIS. Gas prices also affect market prices and thus compliance costs. For the cases in our scenarios the compliance costs are lower in the carbon case despite there being more renewable plant as a result of the relatively higher market prices. The majority of the compliance costs are incurred by NEM participants, which account for between 91 to 93 per cent of the compliance costs in the reference case and 77 to 91 per cent in the carbon case.

Finally, our results are sensitive to assumptions about the limitations for wind generation construction in each year. If there is improved scope to construct wind generation then the LRET shortfall decreases. The reverse also holds if there are buffer zones between residential buildings and wind turbines because progressively less economic sites would be available and so more investments would require support above the penalty price and the shortfall would rise. For similar reasons if the cost of wind investment is more/less than the assumed price in the AEMO/DRET database the shortfall will be more/less also. However, on the data used for this study wind still enjoys a cost advantage over all but biomass as shown in Table 4.1.

The difference in the cost between wind and geothermal is only $5/MWh by FY2030, although it is greater in the earlier years. While biomass is the lowest cost renewable generation the modelling assumed that the availability of future capacity was limited.

Table 4.1: Technology Cost Assumptions Comparison

Technology	Capital cost in FY2030 ($2010/11)	LRMC ($/MWh)
Wind	2,561	87
Geothermal	7,017	92
Solar Thermal	2,056	100
Biomass	5,000	62

In addition, under the carbon price case, the LRET is achieved reflecting higher wholesale market prices which make additional renewable resources economic but interestingly initially makes coal resources more profitable until the price rises to the point where coal is more expensive to operate than other plant. High gas prices also increase the market price and make coal more profitable for the same carbon price.

Absent the establishment of a direct price on carbon, for the LRET to be achieved one or a combination of changes would need to be made, namely:

- an increase in the penalty price;
- indexing of the penalty price; and/or
- changes in the market parameters (ie, the market price cap and associated cumulative price threshold) to increase the revenue that can be earned from the wholesale spot market.

4.7. Supply and demand balance and unserved energy

In the NEM, under the reference case and given the current market parameters, the effect of the LRET is to dampen average wholesale market prices (compared against the counterfactual) thereby reducing the revenue that can be earned by new entrant generation. When this outcome is combined with the effect of the market price cap and cumulative price threshold, which limit the potential for extremely high prices, the modelling results indicate that there is insufficient revenue to support sufficient new investment to meet the reliability standard. The model seeks out the minimum cost of supplying energy over the full modelling horizon and so may “accept” short bursts of unserved energy valued at the market price, which delay new investment accordingly. However, in practice if these circumstances were to arise in the market, the AEMO would use its reliability and emergency reserve trader (RERT) powers to ensure the reliability standard is not breached. Therefore, the results of the modelling may not strictly represent what might actually happen with unserved energy in the market..

Outside the NEM investment is made to meet reserve margins and so we assume it is not dependent on market prices in the same way as it is in the NEM. As a result the risk of unserved energy outside the NEM is determined by the reserve margin with prices moving to what ever level is required.

Figure 4.20 to Figure 4.22 sets out the model results for unserved energy compared to the NEM reliability standard of 0.002 per cent for the reference case, counterfactual case and carbon cases, respectively. We have reported results for Victoria and South Australia on a combined basis. The reason for this is that the model does not account for the NEM operating policy and over allocates unserved energy to South Australia and under allocates to Victoria simply on the basis of transmission losses. The values shown do not account for shortfalls in South Australia due to failure of the interconnector to South Australia that in practice would increase the share of unserved energy in South Australia.

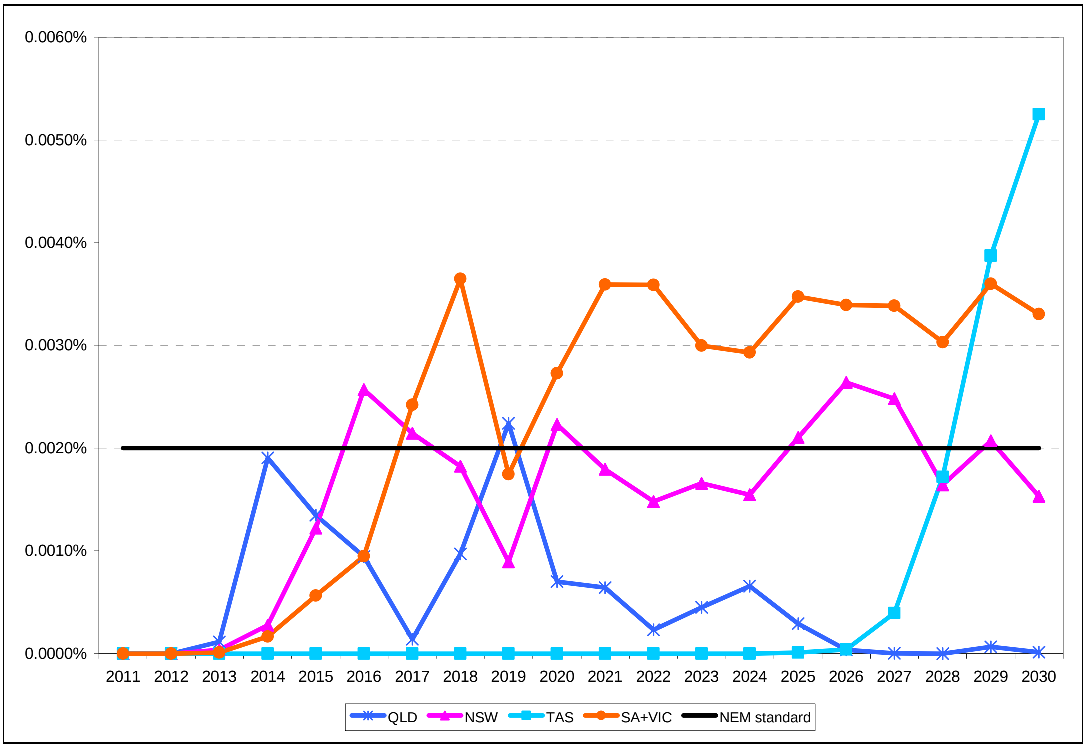
We emphasise that the conclusion that there will be insufficient investment presumes that peaking investments will be made only on the basis of expected value of spot revenues over a number of years in the future or that contracts will be priced at the expected spot price. This presumption may be:

- optimistic (ie, over-estimate the level of peaking plant investment), in the sense that investors in peaking plant may require higher returns or shorter payback periods because of the uncertainty of the revenue stream to peaking plant, concern about continued transmission access and concern about policy stability; or
- pessimistic, in the sense that more investment may result because retailers are prepared to pay a sufficient contract premium or investments are made within a vertically integrated entity seeking to reduce exposure to spot under high demand conditions.

Hence, while our results indicate the potential for outcomes to breach the reliability standard, we have not, within this project, undertaken detailed analysis of the unserved energy situation. Our conclusion in relation to unserved energy should therefore be regarded as pointing to a potential problem that warrants further consideration and comprehensive study, including potentially identifying options to address the problem, rather than being definitive at this time.

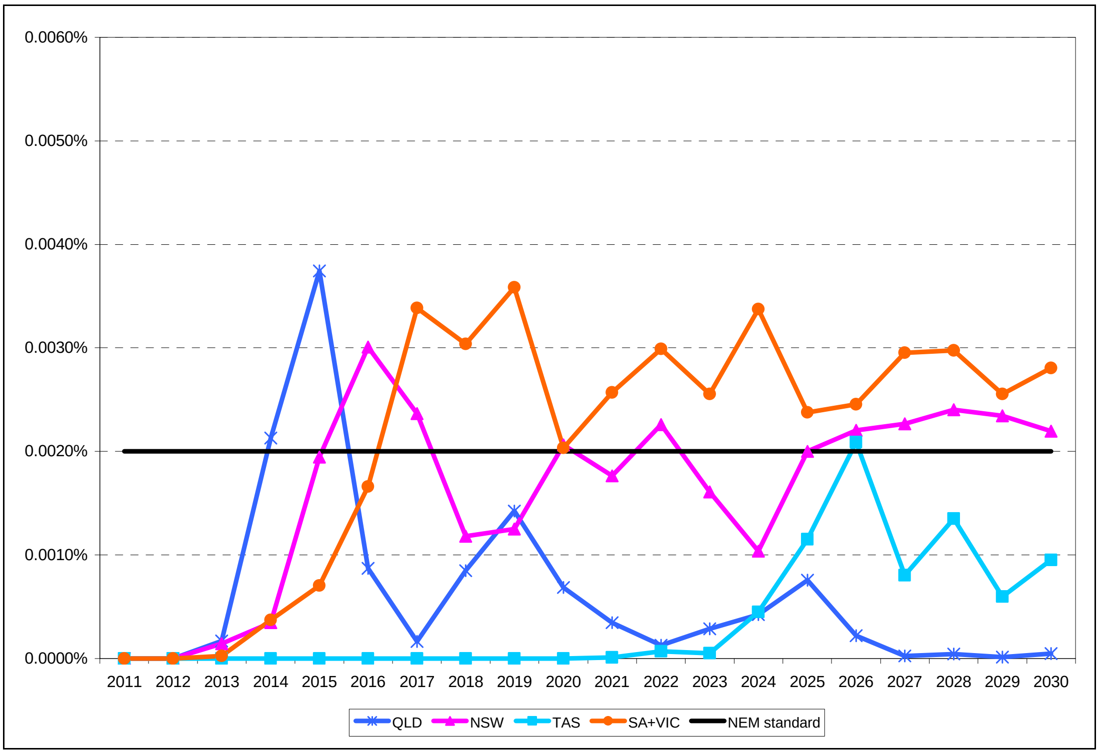
Finally, there is potential for spikes in unserved energy due to the economic trade-off between the cost of investment and unserved energy (noted above) – see results for Tasmania in Figure 4.20. This is because the model is not able to assess the benefits of the investment past the end of the modelling horizon.

Figure 4.20: Proportion of Unserved Energy - Reference Case



Note: Data represents financial years (eg, 2011 is 2011/12)

Figure 4.21: Proportion of Unserved Energy - Counterfactual Case



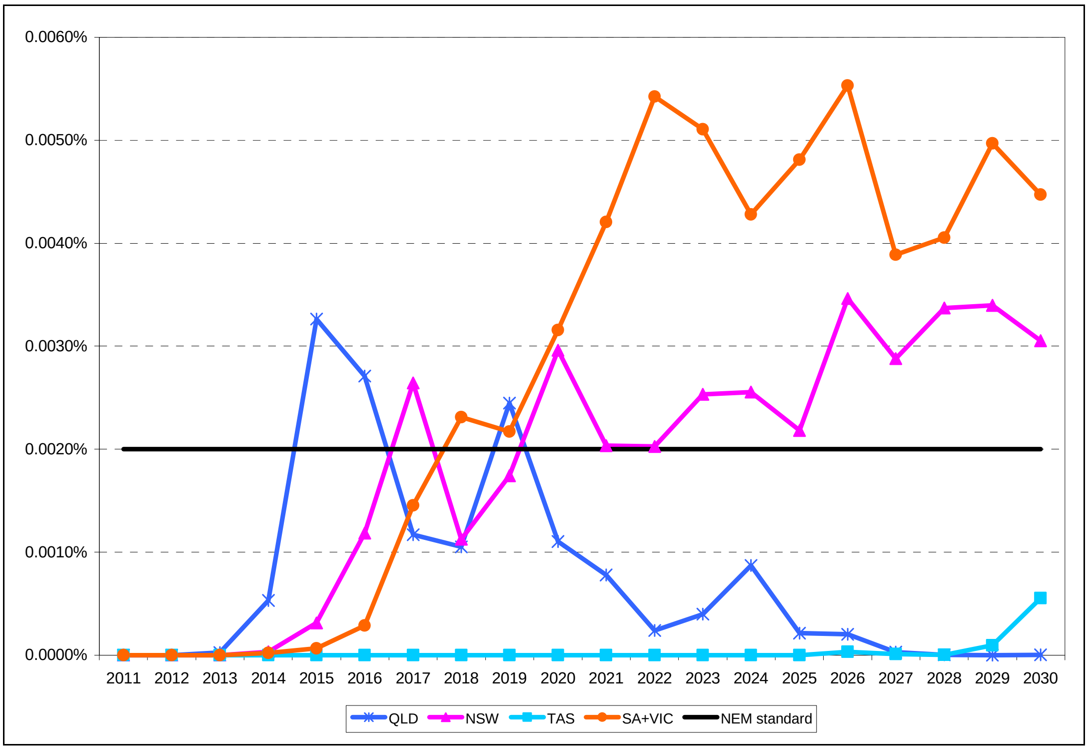
Note: Data represents financial years (eg, 2011 is 2011/12)

In the carbon cases reported unserved energy remains above the reliability standard in some regions – Figure 4.22 and Figure 4.23. This is due to the combined impact of increased renewable investment and the existing market price cap. Unserved energy arises during peak periods when the spot market price is equal to the market price cap. The introduction of a carbon price therefore has no impact on the peak spot market prices when unserved energy arises.

The introduction of a carbon price increases the average spot market price, which in turn leads to more renewable investment. This results in the full LRET target being met - predominantly by wind generation in the cases we examined. As wind generation only contributes approximately three per cent to peak capacity (when unserved energy arises), increasing the amount of wind generation has almost no impact on the levels of unserved energy. The impact of increased wind generation is observed through a increased contribution to base and intermediate energy output.Overall, the plant mix changes but the unserved energy does not shift in all regions.

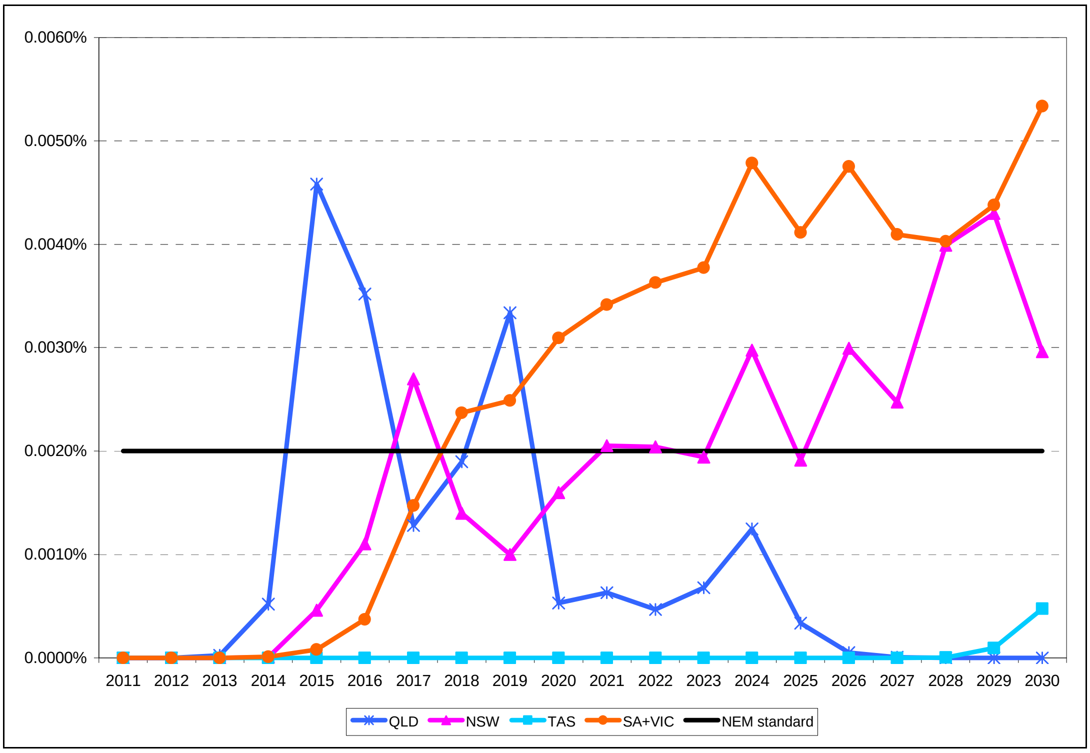
Our results are also affected by the modelling methodology, which uses multiple iterations to find the level of profitable new entrant OCGT and CCGT and, in the reference case, the level of renewable plant that requires no more support than the LRET penalty price. This is an inherently approximate process and minor changes can shift the observed level of unserved energy. This further highlights the need to undertake a more detailed study before drawing definitive conclusions about unserved energy.

Figure 4.22
Proportion of Unserved Energy - Carbon Price Scenario 1



Note: Data represents financial years (eg, 2011 is 2011/12)

Figure 4.23: Proportion of Unserved Energy - Carbon Price Scenario 2



Note: Data represents financial years (eg, 2011 is 2011/12)

4.8. Transmission interconnections

An economic case to augment interconnectors is critically dependent on forecasts of inter-regional transfers. These transfers will generally reflect the relative economics of investment and dispatch in the relevant regions. However, other more complex factors can also affect these transfers. For example arrangements relating to fuel such as take or pay gas contracts or hydro requirements, minimum generation levels in a region to act as reserve against failure of an interconnector or to ensure stable technical operation if low inertia wind generation is the dominant technology.

Predicting how each of these complicating factors will evolve over 10-15 years is difficult and any analysis of the potential for network augmentation would be expected to assess a range of possibilities. In the course of this work we focussed on economic dispatch using the AEMO data for costs for fuel and capital. The resulting inter regional transfers indicated a relatively strong case for an eventual augmentation of connection with South Australia – we assumed a nominal increase of 500MW. It also showed that in the latter part of the study the Queensland price was below the NSW price for a number of years suggesting potential upgrade there as well. However, because it was late in the study horizon we did not include it.

In including an upgrade of the South Australian interconnection we note that generation from gas plants within South Australia falls to relatively low levels compared to historic output and South Australia imports significantly. Because dispatch was on the basis of simple relative prices this outcome represents the strongest case for augmentation and we note that if one or more of the complex factors noted above lead to higher generation within South Australia on a sustained basis the case for augmentation may not be as strong.

We also note that within the load block approach to modelling the dispatch of wind was not based on wind profiles and therefore did not show cases where export might be economic and reinforce the case for augmentation.

Finally, as we assumed a low contribution to peak there was significant peaking investment in the region to cater for situations when wind output is low.

4.9. Conclusions arising from the results

The modelling results provide an indication of the likely market price outcomes of the LRET compared against a counterfactual and in circumstances where carbon prices are introduced. The implications for the cost of electricity to retailers are a combination of the wholesale spot price outcome and the cost of renewable energy represented in the implied renewable energy certificate price. In the WEM, the cost of electricity also needs to consider the direct capacity costs.

Importantly in the NEM, the LRET results in wholesale electricity prices being approximately $13/MWh higher in the reference case as compared to the counterfactual in FY2020. That said it is worth noting again that under no cases has the NEM reliability standard been met, suggesting that the actual wholesale price outcome might indeed be higher than those predicted through our modelling although this may not be reflected in changes to the differences between the cases and therefore to the effect on price of the LRET.

In addition to the market price outcomes, the results indicate that in the absence of a carbon price, the LRET will not be achieved by FY2020. On the data and other assumptions the shortfall in the LRET might be as high as 35 to 40 per cent of the NEM share of the target. This outcome is very sensitive to the combination of assumptions, for example expected limitations in wind generation investment, price of gas and the cost of new renewable and non-renewable plant. The interaction of the particular combination of assumptions and the current penalty price means that not enough renewable generation investments are profitable and so are not constructed.

Finally, we have not explicitly examined how the results might have changed under alternative gas price or generation technology cost assumptions. While this would impact on the results, we believe that the overall conclusions from our modelling are unlikely to be affected. Regardless, further and more detailed modelling would be required to determine the influence these assumptions have on the results but more importantly to consider how to address unserved energy exceeding the reliability standard in the NEM.

Appendix A. Detailed data inputs

The peak demand and energy (sent out) forecasts (less non-scheduled generation) used in this study are set out in the tables below.

Table A.1: NEM and SWIS Peak Demand Forecasts Net of Non-Scheduled Generation - with Carbon

	10% POE Medium Growth MD (MW)					
	QLD	**NSW**	**VIC**	**SA**	**TAS**	**WA SWIS**
FY2011	10,624	15,564	10,815	3,594	1,929	N/A
FY2012	11,328	15,501	11,006	3,543	1,872	N/A
FY2013	12,025	16,038	11,238	3,643	1,851	N/A
FY2014	12,576	16,253	11,403	3,722	1,950	N/A
FY2015	13,104	16,437	11,562	3,758	1,955	N/A
FY2016	13,658	16,809	11,833	3,844	1,908	N/A
FY2017	14,228	17,287	12,287	3,960	1,964	N/A
FY2018	14,817	17,884	12,901	4,090	2,067	N/A
FY2019	15,204	18,457	13,300	4,225	2,184	N/A
FY2020	15,452	18,973	13,491	4,299	2,273	N/A
FY2021	15,765	19,251	13,860	4,364	2,326	N/A
FY2022	16,088	19,471	14,159	4,438	2,357	N/A
FY2023	16,394	19,692	14,566	4,528	2,392	N/A
FY2024	16,686	20,008	14,795	4,609	2,433	N/A
FY2025	17,027	20,348	15,050	4,707	2,468	N/A
FY2026	17,453	20,717	15,385	4,812	2,525	N/A
FY2027	18,088	21,093	15,828	4,921	2,605	N/A
FY2028	18,759	21,615	16,257	5,032	2,707	N/A
FY2029	19,458	22,149	16,697	5,145	2,813	N/A
FY2030	20,169	22,620	17,095	5,247	2,875	N/A

Source: AEMO, 2010 NTNDP study, "2010 NTNDP Energy and MD Forecasts.xlsx", see: http://wwww.aemo.com.au/planning/2010ntndp_cd/home.htm.
Note: Data represents financial years (eg, FY2011 is 2011/12)

Table A.2: NEM and SWIS Peak Demand Forecasts Net of Non-Scheduled Generation – without Carbon

	10% POE Medium Growth MD (MW)					
	QLD	**NSW**	**VIC**	**SA**	**TAS**	**WA SWIS**
FY2011	10,671	15,692	10,820	3,623	1,951	4,793
FY2012	11,452	15,819	11,018	3,612	1,925	4,986
FY2013	12,165	16,379	11,251	3,717	1,905	5,370
FY2014	12,731	16,614	11,416	3,801	2,009	5,601
FY2015	13,272	16,820	11,577	3,842	2,017	5,767
FY2016	13,841	17,218	11,848	3,934	1,973	5,955
FY2017	14,426	17,726	12,303	4,057	2,035	6,168
FY2018	15,030	18,354	12,919	4,194	2,144	6,343
FY2019	15,430	18,960	13,318	4,337	2,266	6,517
FY2020	15,692	19,511	13,510	4,417	2,361	6,689
FY2021	16,020	19,821	13,880	4,489	2,419	6,866
FY2022	16,360	20,075	14,181	4,571	2,456	7,047
FY2023	16,684	20,329	14,589	4,670	2,496	7,233
FY2024	16,994	20,684	14,819	4,760	2,545	7,424
FY2025	17,355	21,064	15,075	4,867	2,588	7,620
FY2026	17,803	21,475	15,412	4,983	2,652	7,821
FY2027	18,464	21,894	15,856	5,102	2,740	8,027
FY2028	19,164	22,468	16,286	5,223	2,849	8,239
FY2029	19,892	23,057	16,728	5,346	2,963	8,456
FY2030	20,645	23,599	17,128	5,464	3,037	8,680

Source: AEMO, 2010 NTNDP study, "2010 NTNDP Energy and MD Forecasts.xlsx", see: http://wwww.aemo.com.au/planning/2010ntndp_cd/home.htm; and Independent Market Operator, Statement of Opportunities, July 2010.
Note: Data represents financial years (eg, FY2011 is 2011/12)

Table A.3: NEM and SWIS Peak Demand Forecasts Net of Non-Scheduled Generation – with Carbon

	50% POE Medium Growth MD (MW)					
	QLD	**NSW**	**VIC**	**SA**	**TAS**	**WA SWIS**
FY2011	14,583	10,092	10,093	3,294	1,904	N/A
FY2012	14,507	10,759	10,194	3,273	1,846	N/A
FY2013	14,992	11,421	10,384	3,353	1,825	N/A
FY2014	15,169	11,944	10,598	3,403	1,923	N/A
FY2015	15,337	12,445	10,742	3,462	1,928	N/A
FY2016	15,663	12,971	10,949	3,538	1,882	N/A
FY2017	16,107	13,511	11,428	3,599	1,937	N/A
FY2018	16,662	14,070	11,897	3,733	2,039	N/A
FY2019	17,184	14,436	12,312	3,846	2,154	N/A
FY2020	17,653	14,672	12,521	3,909	2,242	N/A
FY2021	17,913	14,968	12,858	3,976	2,294	N/A
FY2022	18,119	15,274	13,079	4,040	2,325	N/A
FY2023	18,324	15,565	13,353	4,118	2,359	N/A
FY2024	18,627	15,841	13,541	4,199	2,399	N/A
FY2025	18,934	16,164	13,808	4,285	2,434	N/A
FY2026	19,285	16,569	14,141	4,377	2,490	N/A
FY2027	19,633	17,171	14,604	4,482	2,569	N/A
FY2028	20,117	17,809	14,971	4,578	2,669	N/A
FY2029	20,612	18,472	15,348	4,676	2,773	N/A
FY2030	21,042	19,146	15,692	4,766	2,835	N/A

Source: AEMO, 2010 NTNDP study, "2010 NTNDP Energy and MD Forecasts.xlsx", see: http://wwww.aemo.com.au/planning/2010ntndp_cd/home.htm.
Note: Data represents financial years (eg, FY2011 is 2011/12)

Table A.4: NEM and SWIS Peak Demand Forecasts Net of Non-Scheduled Generation – without Carbon

	50% POE Medium Growth MD (MW)					
	QLD	**NSW**	**VIC**	**SA**	**TAS**	**WA SWIS**
FY2011	14,703	10,137	10,098	3,320	1,925	4,401
FY2012	14,805	10,877	10,205	3,337	1,899	4,569
FY2013	15,312	11,554	10,396	3,422	1,879	4,928
FY2014	15,507	12,091	10,610	3,476	1,982	5,140
FY2015	15,695	12,605	10,756	3,539	1,990	5,288
FY2016	16,045	13,145	10,963	3,621	1,946	5,453
FY2017	16,516	13,699	11,443	3,688	2,007	5,645
FY2018	17,100	14,272	11,913	3,829	2,115	5,799
FY2019	17,654	14,651	12,329	3,948	2,236	5,951
FY2020	18,155	14,899	12,539	4,017	2,329	6,102
FY2021	18,444	15,210	12,877	4,091	2,386	6,257
FY2022	18,681	15,533	13,099	4,161	2,422	6,416
FY2023	18,919	15,841	13,374	4,248	2,462	6,578
FY2024	19,258	16,134	13,563	4,337	2,510	6,745
FY2025	19,601	16,476	13,831	4,432	2,552	6,916
FY2026	19,992	16,901	14,165	4,533	2,616	7,092
FY2027	20,381	17,529	14,629	4,647	2,702	7,272
FY2028	20,913	18,193	14,998	4,753	2,810	7,456
FY2029	21,459	18,885	15,376	4,860	2,921	7,646
FY2030	21,954	19,598	15,723	4,964	2,995	7,840

Source: AEMO, 2010 NTNDP study, "2010 NTNDP Energy and MD Forecasts.xlsx", see: http://wwww.aemo.com.au/planning/2010ntndp_cd/home.htm; and Independent Market Operator, Statement of Opportunities, July 2010.
Note: Data represents financial years (eg, FY2011 is 2011/12)

Table A.5: NEM and SWIS Sent Out Energy (GWh) Net of Non-Scheduled Generation –with Carbon

	QLD	NSW	VIC	SA	TAS	WA SWIS
FY2011	53,562	73,883	47,226	14,818	10,190	N/A
FY2012	56,523	73,612	47,357	14,785	9,925	N/A
FY2013	59,431	74,665	47,750	15,012	10,029	N/A
FY2014	61,722	75,504	48,204	15,183	9,969	N/A
FY2015	64,032	76,574	48,806	15,287	9,891	N/A
FY2016	66,474	77,794	49,735	15,485	9,932	N/A
FY2017	69,047	79,434	51,064	15,820	10,191	N/A
FY2018	71,571	81,569	52,581	16,287	10,652	N/A
FY2019	73,808	83,659	53,913	16,669	11,180	N/A
FY2020	75,579	85,187	54,942	16,960	11,604	N/A
FY2021	77,026	86,180	55,946	17,214	11,838	N/A
FY2022	78,389	87,060	57,027	17,514	11,947	N/A
FY2023	79,677	88,122	58,064	17,838	12,054	N/A
FY2024	81,013	89,222	59,057	18,191	12,192	N/A
FY2025	82,620	90,342	60,124	18,561	12,355	N/A
FY2026	84,883	91,808	61,440	18,962	12,603	N/A
FY2027	87,778	93,609	62,973	19,393	12,957	N/A
FY2028	90,887	95,423	64,448	19,829	13,426	N/A
FY2029	93,549	96,846	65,596	20,218	13,869	N/A
FY2030	96,674	98,294	66,677	20,587	14,138	N/A

Source: AEMO, 2010 NTNDP study, "2010 NTNDP Energy and MD Forecasts.xlsx", see: http://wwww.aemo.com.au/planning/2010ntndp_cd/home.htm.
Note: Data represents financial years (eg, FY2011 is 2011/12)

Table A.6: NEM and SWIS Sent Out Energy (GWh) Net of Non-Scheduled Generation – without Carbon

	QLD	NSW	VIC	SA	TAS	WA SWIS
FY2011	53,797	74,482	47,249	14,933	10,308	18,944
FY2012	57,138	75,092	47,408	15,068	10,217	19,321
FY2013	60,118	76,222	47,803	15,313	10,333	21,041
FY2014	62,476	77,146	48,260	15,500	10,283	22,006
FY2015	64,848	78,318	48,865	15,621	10,217	22,478
FY2016	67,356	79,647	49,797	15,843	10,283	22,999
FY2017	69,994	81,404	51,129	16,203	10,570	23,785
FY2018	72,585	83,667	52,650	16,696	11,059	24,219
FY2019	74,893	85,890	53,986	17,103	11,615	24,630
FY2020	76,734	87,552	55,019	17,419	12,067	25,024
FY2021	78,256	88,678	56,027	17,701	12,327	25,424
FY2022	79,700	89,702	57,113	18,032	12,461	25,831
FY2023	81,069	90,916	58,154	18,388	12,596	26,244
FY2024	82,491	92,176	59,152	18,776	12,770	26,664
FY2025	84,189	93,455	60,222	19,183	12,971	27,091
FY2026	86,561	95,097	61,544	19,624	13,256	27,524
FY2027	89,580	97,094	63,083	20,094	13,643	27,964
FY2028	92,819	99,116	64,562	20,569	14,149	28,412
FY2029	95,616	100,754	65,716	21,002	14,640	28,866
FY2030	98,931	102,480	66,805	21,430	14,966	29,328

Source: AEMO, 2010 NTNDP study, "2010 NTNDP Energy and MD Forecasts.xlsx", see: http://wwww.aemo.com.au/planning/2010ntndp_cd/home.htm; and Independent Market Operator, Statement of Opportunities, July 2010.
Note: Data represents financial years (eg, FY2011 is 2011/12)

In addition, because the NEM forecasts for maximum demand are presented in "as generated" terms but energy is presented on a "sent out" basis and the NEM scheduling process functions on an as generated basis, it is necessary to convert the energy forecasts to an "as generated basis". The AEMO publish regional scaling factors for this purpose as shown in Table A.7. WEM operates on a sent out basis and the forecasts are also on a sent out basis and as a result a similar conversion is unnecessary for the WEM.

Table A.7: Scaling factors applied for JPB forecast Annual Energy (GWh) to convert from "sent out" to "as generated"

Region	QLD	NSW	VIC	SA	TAS
FY2011	1.063	1.058	1.086	1.036	1.001
FY2012	1.060	1.057	1.084	1.035	1.002
FY2013	1.060	1.057	1.079	1.033	1.002
FY2014	1.057	1.057	1.076	1.029	1.002
FY2015	1.057	1.055	1.074	1.029	1.002
FY2016	1.057	1.055	1.073	1.026	1.003
FY2017	1.057	1.053	1.068	1.023	1.003
FY2018	1.056	1.052	1.067	1.023	1.003
FY2019	1.056	1.051	1.067	1.023	1.003
FY2020	1.053	1.051	1.063	1.023	1.003
FY2021	1.053	1.049	1.063	1.024	1.004
FY2022	1.051	1.046	1.059	1.022	1.004
FY2023	1.050	1.044	1.056	1.023	1.004
FY2024	1.049	1.042	1.053	1.023	1.004
FY2025	1.048	1.040	1.053	1.023	1.004
FY2026	1.046	1.047	1.050	1.022	1.004
FY2027	1.045	1.053	1.060	1.023	1.004
FY2028	1.043	1.059	1.070	1.023	1.004
FY2029	1.043	1.059	1.070	1.023	1.004
Average	**1.053**	**1.052**	**1.068**	**1.026**	**1.003**

Source: AEMO, 2010 NTNDP study, "2010 NTNDP Energy and MD Forecasts.xlsx", see: http://wwww.aemo.com.au/planning/2010ntndp_cd/home.htm.
Note: Data represents financial years (eg, FY2011 is 2011/12)

Finally, the modelling is based on a regional representation of the NEM, which takes into account transmission interconnection capacity and losses between regions.

Interconnectors are represented by linear losses based on an approximation developed from previous analysis of typical flows and marginal loss equations published by the AEMO. This is a simplification needed for the load block form of analysis and is intended to strike a balance between representation of the impact of marginal losses on price outcomes and actual (average) losses impacting physical dispatch.

Table A.8 sets out the key interconnection assumptions used. We identified a number of augmentations between regions and included these in the final study. We have also noted situations where the results were indicating the potential for further augmentations that we did not specifically examine.

The WEM and DKIS system are isolated systems and all network connections are internal.

Table A.8: Initial NEM Interconnector Characteristics

Interconnector	From	To	Max Forward (MW)	Max Reverse (MW)	Average Loss Factor
Basslink	TAS	VIC	594	478	0.09
Terannora	NSW	QLD	122	220	0.05
QNI	NSW	QLD	550	1,078	0.05
Murraylink	VIC	SA	220	120	0.025
Heywood	VIC	SA	460	460	0.025
VIC-NSW	VIC	NSW	1,500	1,000	0.12

Appendix B. Detailed results

This Appendix provides the annual weighted average prices, installed capacity (MW) and energy sent out (MWh) for each of the scenarios considered in the NEM and WEM.

Table B.1: NEM Weighted Average Prices ($/MWh) – Reference Case

	Illustrative contract	QLD	NSW	VIC	SA	TAS	2030 LRMC CCGT
FY2011	40.0	26.6	27.8	29.0	29.7	29.4	
FY2012	40.0	27.4	28.2	26.7	27.2	26.4	
FY2013	40.0	30.6	31.0	29.2	29.7	28.4	
FY2014		34.5	33.6	32.7	33.2	31.6	
FY2015		35.2	35.7	35.0	35.6	33.4	
FY2016		37.5	38.1	37.5	38.1	34.2	
FY2017		38.7	39.8	39.8	40.2	36.5	
FY2018		48.3	47.2	49.1	50.2	45.9	
FY2019		50.0	48.2	49.0	49.9	45.1	
FY2020		54.8	51.2	51.5	52.5	45.0	
FY2021		59.7	55.1	56.7	57.8	52.7	
FY2022		61.7	61.5	64.6	66.0	60.6	
FY2023		63.0	63.1	65.8	67.3	62.5	

FY2024		65.5	65.4	68.2	69.8	66.0	
FY2025		64.1	66.0	68.8	70.4	67.9	
FY2026		63.8	66.2	68.9	70.6	68.7	
FY2027		67.4	71.8	73.9	75.8	74.7	
FY2028		67.0	70.7	71.1	72.9	73.7	73.0
FY2029		67.1	71.4	74.7	76.6	78.1	73.0
FY2030		66.3	70.4	74.2	76.0	77.7	73.0

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.2: NEM Weighted Average Prices ($/MWh) – Reference Case LRET Enforced

	Illustrative contract	QLD	NSW	VIC	SA	TAS	2030 LRMC CCGT
FY2011	40.0	26.6	27.8	29.0	29.7	29.4	
FY2012	40.0	26.6	27.1	26.3	26.9	26.2	
FY2013	40.0	29.1	29.4	28.0	28.6	27.2	
FY2014		40.5	32.0	31.1	31.7	30.4	
FY2015		33.7	34.5	33.8	34.4	32.6	
FY2016		34.9	35.8	34.6	35.1	31.5	
FY2017		37.8	39.1	37.3	37.9	32.9	
FY2018		46.2	44.4	44.4	45.3	41.2	
FY2019		48.0	45.2	45.6	46.3	43.2	
FY2020		49.6	46.7	43.7	44.2	40.9	

FY2021	51.4	48.4	48.7	49.6	45.7	
FY2022	52.9	50.3	51.7	52.6	48.0	
FY2023	55.5	52.4	54.0	55.2	52.7	
FY2024	59.2	56.9	58.2	59.4	58.5	
FY2025	60.1	60.1	62.8	64.2	65.1	
FY2026	62.0	63.2	66.4	67.9	69.6	
FY2027	66.8	67.4	70.0	71.7	73.5	
FY2028	68.8	68.9	71.4	73.2	75.2	73.0
FY2029	66.4	67.6	71.4	73.2	75.4	73.0
FY2030	66.3	68.5	72.4	74.2	76.3	73.0

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.3: WEM Weighted Average Prices($/MWh) – Reference and Carbon Case

	Reference case	Carbon case
FY2011	66.5	66.5
FY2012	67.7	83.6
FY2013	66.7	83.3
FY2014	66.7	84.0
FY2015	67.0	85.1
FY2016	67.5	86.3
FY2017	72.2	91.1
FY2018	77.5	96.1

FY2019	78.2	95.9
FY2020	78.5	94.2
FY2021	79.5	93.9
FY2022	80.0	94.8
FY2023	80.8	96.5
FY2024	81.6	98.3
FY2025	81.9	92.0
FY2026	82.3	93.6
FY2027	82.9	94.9
FY2028	83.5	94.3
FY2029	84.1	95.8
FY2030	84.7	97.3

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.4: NEM Weighted Average Prices($/MWh) – Counterfactual Case

	Illustrative contract	QLD	NSW	VIC	SA	TAS	2030 LRMC CCGT
FY2011	40.0	26.6	27.8	29.0	29.7	29.4	
FY2012	40.0	28.4	29.4	30.4	31.1	30.7	
FY2013	40.0	31.7	32.4	33.5	34.2	33.5	
FY2014		38.1	35.2	36.7	37.4	36.5	
FY2015		41.9	41.5	42.2	43.0	39.5	

FY2016	40.3	41.9	43.6	44.5	41.3	
FY2017	42.0	43.9	46.7	47.6	46.1	
FY2018	53.2	52.9	63.4	64.9	62.7	
FY2019	58.2	57.2	67.9	69.2	68.8	
FY2020	62.2	61.5	65.2	66.6	66.4	
FY2021	64.8	64.4	68.4	69.9	70.3	
FY2022	65.2	67.3	71.1	72.7	73.0	
FY2023	63.7	65.9	69.6	71.3	71.9	
FY2024	65.4	67.6	71.5	73.3	75.0	
FY2025	65.6	67.7	70.3	72.1	74.8	
FY2026	64.2	67.2	69.5	71.3	74.3	
FY2027	68.1	72.3	74.0	75.8	77.9	
FY2028	68.0	74.1	74.5	76.4	77.8	73.0
FY2029	66.6	72.0	73.9	75.9	77.7	73.0
FY2030	66.0	71.1	73.1	75.2	76.4	73.0

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.5: NEM Weighted Average Prices($/MWh) – Carbon Price Scenario 1

	QLD	NSW	VIC	SA	TAS
FY2011	26.0	27.1	28.3	28.9	28.6
FY2012	48.4	50.1	51.9	53.0	50.4
FY2013	51.5	52.9	52.9	54.0	51.2

FY2014	55.1	55.3	58.3	59.5	55.8
FY2015	64.3	60.4	62.3	63.4	58.7
FY2016	64.2	64.0	65.3	66.4	58.6
FY2017	66.1	67.7	68.6	69.6	61.4
FY2018	74.9	73.3	71.5	73.1	66.3
FY2019	78.5	74.9	73.5	75.2	70.6
FY2020	81.0	79.2	76.6	78.3	72.5
FY2021	82.1	80.9	80.0	81.8	77.5
FY2022	82.2	83.9	86.7	88.8	84.5
FY2023	83.0	85.6	89.6	91.7	86.1
FY2024	86.2	88.6	91.3	93.5	87.5
FY2025	84.5	88.7	90.8	93.0	88.1
FY2026	86.2	91.2	91.5	93.8	90.6
FY2027	85.3	92.2	91.1	93.3	91.0
FY2028	85.3	93.9	92.7	95.0	91.9
FY2029	85.4	96.1	96.2	98.6	93.4
FY2030	85.1	97.3	95.2	97.6	93.7

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.6: NEM Weighted Average Prices($/MWh) – Carbon Price Scenario 2

	QLD	NSW	VIC	SA	TAS
FY2011	26.0	27.1	28.3	28.9	28.6

FY2012	49.4	51.1	53.1	54.3	51.5
FY2013	52.7	54.1	53.6	54.7	51.9
FY2014	57.6	56.8	59.8	60.9	57.4
FY2015	69.7	62.0	63.8	64.9	60.5
FY2016	69.6	66.6	67.5	68.6	61.0
FY2017	68.6	70.3	71.1	72.1	64.1
FY2018	77.8	76.1	74.0	75.6	68.9
FY2019	82.2	79.8	78.4	80.1	75.6
FY2020	81.1	80.2	78.5	80.2	75.3
FY2021	85.3	84.7	84.3	86.2	81.6
FY2022	84.2	86.6	87.3	89.3	85.9
FY2023	86.1	89.0	88.8	90.9	86.4
FY2024	92.3	94.5	93.2	95.4	90.7
FY2025	87.2	91.5	91.8	94.1	89.5
FY2026	89.6	95.1	95.1	97.5	93.1
FY2027	91.3	99.0	98.2	100.7	96.1
FY2028	91.0	104.6	99.1	101.6	96.4
FY2029	90.7	105.1	99.2	101.7	97.7
FY2030	90.9	105.4	99.3	101.8	100.4

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.7: NEM Installed Capacity (MW) – Reference Case

	Super-critical black coal	Sub-critical black coal	Sub-critical brown coal	Cogeneration	Steam gas	Hydro	CCGT	OCGT	OCGT-liquids	Biomass	Wind	Total
FY2011	2,853	17,538	7,490	524	1,780	7,792	2,305	5,743	688	-	763	47,476
FY2012	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	100	1,665	48,440
FY2013	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	200	1,735	48,610
FY2014	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	300	1,735	48,710
FY2015	2,853	16,900	7,490	524	1,780	7,792	2,305	6,662	688	400	1,735	49,129
FY2016	2,853	16,900	7,490	524	1,780	7,792	2,305	7,496	688	500	1,735	50,063
FY2017	2,853	16,900	7,490	524	1,780	7,792	2,305	8,744	688	600	1,920	51,596
FY2018	2,853	16,900	7,250	524	1,780	7,792	2,305	10,678	688	700	2,427	53,897
FY2019	2,853	16,900	7,250	524	1,780	7,792	2,305	12,202	688	800	2,933	56,027
FY2020	2,853	16,900	7,250	524	1,780	7,792	3,338	12,202	688	900	3,773	58,001
FY2021	2,853	16,900	7,250	524	1,780	7,792	4,363	12,287	688	904	3,773	59,114
FY2022	2,853	16,900	7,250	524	1,780	7,792	5,017	12,621	688	908	3,773	60,106
FY2023	2,853	16,900	7,250	524	1,780	7,792	5,451	13,282	688	912	3,773	61,206
FY2024	2,853	16,900	7,250	524	1,780	7,792	5,451	14,291	688	916	3,773	62,218
FY2025	2,853	16,900	7,250	524	1,780	7,792	6,571	14,291	688	919	3,773	63,341
FY2026	2,853	16,900	7,250	524	1,780	7,792	7,915	14,291	688	923	3,773	64,689
FY2027	2,853	16,900	7,250	524	1,780	7,792	9,600	14,297	688	927	3,773	66,385

FY2028	2,853	16,900	7,250	524	1,780	7,792	10,973	14,815	688	931	3,773	68,279
FY2029	2,853	16,900	7,250	524	1,780	7,792	11,801	15,939	688	935	3,773	70,236
FY2030	2,853	16,900	7,250	524	1,780	7,792	12,769	16,813	688	939	3,773	72,081

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.8: NEM Installed Capacity (MW) – Reference Case LRET Enforced

	Super-critical black coal	Sub-critical black coal	Sub-critical brown coal	Cogeneration	Steam gas	Hydro	CCGT	OCGT	OCGT-liquids	Biomass	Wind	Total
FY2011	2,853	17,538	7,490	524	1,780	7,792	2,305	5,743	688	-	763	47,476
FY2012	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	100	3,087	49,862
FY2013	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	200	3,361	50,236
FY2014	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	300	3,361	50,336
FY2015	2,853	16,900	7,490	524	1,780	7,792	2,305	6,614	688	400	3,361	50,707
FY2016	2,853	16,900	7,490	524	1,780	7,792	2,305	7,440	688	500	3,611	51,883
FY2017	2,853	16,900	7,490	524	1,780	7,792	2,305	8,672	688	600	4,317	53,921
FY2018	2,853	16,900	7,250	524	1,780	7,792	2,305	10,590	688	700	5,354	56,736
FY2019	2,853	16,900	7,250	524	1,780	7,792	2,305	11,839	688	800	6,420	59,152
FY2020	2,853	16,900	7,250	524	1,780	7,792	2,583	12,434	688	900	8,032	61,736
FY2021	2,853	16,900	7,250	524	1,780	7,792	2,878	13,237	688	906	8,032	62,841
FY2022	2,853	16,900	7,250	524	1,780	7,792	3,278	13,815	688	913	8,032	63,825
FY2023	2,853	16,900	7,250	524	1,780	7,792	3,451	14,728	688	919	8,032	64,917

FY2024	2,853	16,900	7,250	524	1,780	7,792	3,451	15,727	688	926	8,032	65,922
FY2025	2,853	16,900	7,250	524	1,780	7,792	4,559	15,727	688	932	8,032	67,037
FY2026	2,853	16,900	7,250	524	1,780	7,792	5,891	15,727	688	939	8,032	68,375
FY2027	2,853	16,900	7,250	524	1,780	7,792	7,649	15,798	688	945	8,032	70,210
FY2028	2,853	16,900	7,250	524	1,780	7,792	9,100	16,226	688	952	8,032	72,096
FY2029	2,853	16,900	7,250	524	1,780	7,792	9,943	17,323	688	958	8,032	74,043
FY2030	2,853	16,900	7,250	524	1,780	7,792	11,028	18,067	688	965	8,032	75,879

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.9: SWIS Installed Capacity (MW) – Reference Case

	Sub-critical black coal	Cogeneration	CCGT	OCGT	OCGT-liquids	Biomass+other	Wind	Total
FY2011	2,033	598	491	1,464	475	9	191	5,261
FY2012	2,033	598	491	1,799	475	9	397	5,802
FY2013	2,253	598	491	1,895	549	9	527	6,322
FY2014	2,253	598	491	2,145	549	9	527	6,572
FY2015	2,253	598	491	2,324	549	9	527	6,751
FY2016	2,253	598	491	2,528	549	9	527	6,955
FY2017	2,253	598	491	2,758	549	9	527	7,185
FY2018	2,253	598	491	2,948	549	9	527	7,375
FY2019	2,253	598	491	3,136	549	9	527	7,563
FY2020	2,253	598	677	3,136	549	9	527	7,749

FY2021	2,253	598	677	3,327	549	9	527	7,940
FY2022	2,253	598	677	3,502	549	30	527	8,136
FY2023	2,253	598	677	3,695	549	39	527	8,337
FY2024	2,253	598	677	3,901	549	39	527	8,544
FY2025	2,253	598	889	3,901	549	39	527	8,756
FY2026	2,253	598	1,093	3,915	549	39	527	8,974
FY2027	2,253	598	1,190	4,042	549	39	527	9,197
FY2028	2,253	598	1,310	4,150	549	39	527	9,426
FY2029	2,253	598	1,430	4,266	549	39	527	9,661
FY2030	2,253	598	1,552	4,385	549	39	527	9,903

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.10: NEM Installed Capacity (MW) – Counterfactual Case

	Super-critical black coal	Sub-critical black coal	Sub-critical brown coal	Cogeneration	Steam gas	Hydro	CCGT	OCGT	OCGT-liquids	Wind	Total
FY2011	2,853	17,538	7,490	524	1,780	7,792	2,305	5,743	688	763	47,476
FY2012	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	816	47,491
FY2013	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	816	47,491
FY2014	2,853	17,500	7,490	524	1,780	7,792	2,305	5,857	688	816	47,605
FY2015	2,853	16,900	7,490	524	1,780	7,792	2,305	6,412	688	816	47,560
FY2016	2,853	16,900	7,490	524	1,780	7,792	2,305	7,675	688	816	48,823

FY2017	2,853	16,900	7,490	524	1,780	7,792	2,498	9,184	688	816	50,525
FY2018	2,853	16,900	7,250	524	1,780	7,792	2,724	11,257	688	816	52,585
FY2019	2,853	16,900	7,250	524	1,780	7,792	2,882	12,507	688	816	53,992
FY2020	2,853	16,900	7,250	524	1,780	7,792	4,286	12,507	688	816	55,396
FY2021	2,853	16,900	7,250	524	1,780	7,792	5,404	12,507	688	816	56,514
FY2022	2,853	16,900	7,250	524	1,780	7,792	6,401	12,507	688	816	57,511
FY2023	2,853	16,900	7,250	524	1,780	7,792	7,235	12,778	688	816	58,616
FY2024	2,853	16,900	7,250	524	1,780	7,792	7,477	13,554	688	816	59,634
FY2025	2,853	16,900	7,250	524	1,780	7,792	8,606	13,554	688	816	60,762
FY2026	2,853	16,900	7,250	524	1,780	7,792	9,960	13,554	688	816	62,117
FY2027	2,853	16,900	7,250	524	1,780	7,792	11,664	13,554	688	816	63,820
FY2028	2,853	16,900	7,250	524	1,780	7,792	13,283	13,839	688	816	65,724
FY2029	2,853	16,900	7,250	524	1,780	7,792	14,541	14,546	688	816	67,690
FY2030	2,853	16,900	7,250	524	1,780	7,792	15,687	15,254	688	816	69,544

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.11: NEM Installed Capacity (MW) – Carbon Price Scenario 1

	Super-critical black coal	Sub-critical black coal	Sub-critical brown coal	Cogeneration	Steam gas	Hydro	CCGT	OCGT	OCGT-liquids	Biomass	Wind	Total
FY2011	2,853	17,538	7,490	524	1,780	7,792	2,305	5,743	688	-	763	47,476

FY2012	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	100	3,087	49,862
FY2013	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	200	3,361	50,236
FY2014	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	300	3,361	50,336
FY2015	2,853	16,900	7,490	524	1,780	7,792	2,305	5,894	688	400	3,532	50,158
FY2016	2,853	16,900	7,490	524	1,780	7,792	2,305	6,674	688	500	3,782	51,288
FY2017	2,853	16,900	7,490	524	1,780	7,792	2,305	7,860	688	600	4,307	53,099
FY2018	2,853	16,900	7,250	524	1,780	7,792	2,305	9,723	688	700	5,335	55,850
FY2019	2,853	16,900	7,250	524	1,780	7,792	2,305	10,916	688	800	6,399	58,207
FY2020	2,853	16,900	7,250	524	1,780	7,792	2,579	11,327	688	900	8,010	60,604
FY2021	2,853	16,900	7,250	524	1,780	7,792	2,970	11,972	688	906	8,010	61,646
FY2022	2,853	16,900	7,250	524	1,780	7,792	3,631	12,224	688	913	8,010	62,565
FY2023	2,853	16,900	7,250	524	1,780	7,792	4,124	12,747	688	919	8,010	63,588
FY2024	2,853	16,900	7,250	524	1,780	7,792	4,263	13,423	688	946	8,010	64,429
FY2025	2,853	16,900	7,250	524	1,780	7,792	5,389	13,423	688	946	8,010	65,555
FY2026	2,853	16,900	7,250	524	1,780	7,792	6,643	13,423	688	946	8,010	66,809
FY2027	2,853	16,900	7,250	524	1,780	7,792	8,458	13,423	688	1,019	8,010	68,698
FY2028	2,853	16,900	7,250	524	1,780	7,792	10,146	13,423	688	1,119	8,010	70,486
FY2029	2,853	16,900	7,250	524	1,780	7,792	11,165	14,162	688	1,206	8,010	72,331
FY2030	2,853	16,900	7,250	524	1,780	7,792	12,218	14,807	688	1,206	8,030	74,048

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.12: NEM Installed Capacity (MW) – Carbon Price Scenario 2

	Super-critical black coal	Sub-critical black coal	Sub-critical brown coal	Cogeneration	Steam gas	Hydro	CCGT	OCGT	OCGT-liquids	Biomass	Wind	Total
FY2011	2,853	17,538	7,490	524	1,780	7,792	2,305	5,743	688	-	763	47,476
FY2012	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	100	1,665	48,440
FY2013	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	200	1,735	48,610
FY2014	2,853	17,500	7,490	524	1,780	7,792	2,305	5,743	688	300	1,735	48,710
FY2015	2,853	16,900	7,490	524	1,780	7,792	2,305	6,662	688	400	1,735	49,129
FY2016	2,853	16,900	7,490	524	1,780	7,792	2,305	7,496	688	500	1,735	50,063
FY2017	2,853	16,900	7,490	524	1,780	7,792	2,305	8,744	688	600	1,920	51,596
FY2018	2,853	16,900	7,250	524	1,780	7,792	2,305	10,678	688	700	2,427	53,897
FY2019	2,853	16,900	7,250	524	1,780	7,792	2,305	12,202	688	800	2,933	56,027
FY2020	2,853	16,900	7,250	524	1,780	7,792	3,338	12,202	688	900	3,773	58,001
FY2021	2,853	16,900	7,250	524	1,780	7,792	4,363	12,287	688	904	3,773	59,114
FY2022	2,853	16,900	7,250	524	1,780	7,792	5,017	12,621	688	908	3,773	60,106
FY2023	2,853	16,900	7,250	524	1,780	7,792	5,451	13,282	688	912	3,773	61,206
FY2024	2,853	16,900	7,250	524	1,780	7,792	5,451	14,291	688	916	3,773	62,218
FY2025	2,853	16,900	7,250	524	1,780	7,792	6,571	14,291	688	919	3,773	63,341

FY2026	2,853	16,900	7,250	524	1,780	7,792	7,915	14,291	688	923	3,773	64,689
FY2027	2,853	16,900	7,250	524	1,780	7,792	9,600	14,297	688	927	3,773	66,385
FY2028	2,853	16,900	7,250	524	1,780	7,792	10,973	14,815	688	931	3,773	68,279
FY2029	2,853	16,900	7,250	524	1,780	7,792	11,801	15,939	688	935	3,773	70,236
FY2030	2,853	16,900	7,250	524	1,780	7,792	12,769	16,813	688	939	3,773	72,081

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.13: SWIS Installed Capacity (MW) – Carbon Case

	Sub-critical black coal	Cogeneration	CCGT	OCGT	OCGT-liquids	Biomass+other	Wind	Total
FY2011	2,033	598	491	1,464	475	9	191	5,261
FY2012	2,033	598	491	1,799	475	9	397	5,802
FY2013	2,253	598	491	1,895	549	9	527	6,322
FY2014	2,253	598	491	2,145	549	9	527	6,572
FY2015	2,253	598	491	2,324	549	9	527	6,751
FY2016	2,253	598	491	2,528	549	9	527	6,955
FY2017	2,253	598	491	2,658	549	109	527	7,185
FY2018	2,253	598	491	2,832	549	109	608	7,439
FY2019	2,253	598	491	2,982	549	109	798	7,780
FY2020	2,253	598	491	3,099	549	109	1,142	8,241
FY2021	2,253	598	491	3,246	549	109	1,363	8,609
FY2022	2,253	598	491	3,426	549	109	1,445	8,871

FY2023	2,253	598	491	3,627	549	109	1,445	9,072
FY2024	2,253	598	491	3,833	549	109	1,445	9,278
FY2025	2,253	598	491	3,862	549	109	2,363	10,225
FY2026	2,253	598	564	4,006	549	109	2,363	10,442
FY2027	2,253	598	670	4,117	549	109	2,395	10,691
FY2028	2,253	598	670	4,292	549	109	2,669	11,140
FY2029	2,253	598	826	4,371	549	109	2,669	11,375
FY2030	2,253	598	984	4,455	549	109	2,669	11,616

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.14: NEM Energy (GWh) – Reference Case

	Super-critical black coal	Sub-critical black coal	Sub-critical brown coal	Cogener ation	Steam gas	Hydro	CCGT	OCGT	OCGT-liquids	Biomass	Wind	Total
FY2011	21,230	97,755	54,580	262	395	16,333	7,971	877	9	-	2,484	201,897
FY2012	21,176	97,810	54,230	264	364	16,333	8,585	1,023	11	764	5,267	205,827
FY2013	21,219	100,488	54,379	351	409	16,333	9,182	1,239	13	1,538	5,489	210,641
FY2014	21,214	102,919	54,568	383	475	16,333	9,414	1,349	15	2,303	5,468	214,442
FY2015	21,168	105,453	54,408	409	602	16,333	9,620	1,999	15	3,086	5,484	218,579
FY2016	21,215	108,511	54,565	1,340	701	16,333	7,883	3,628	16	3,854	5,499	223,546
FY2017	21,225	112,576	54,619	1,503	848	16,333	7,879	4,163	16	4,624	6,116	229,901
FY2018	21,224	123,248	53,409	793	811	16,333	3,755	4,866	17	5,395	7,760	237,612

FY2019	21,219	125,435	53,415	804	953	16,333	4,857	5,992	17	6,159	9,323	244,507
FY2020	21,211	125,864	53,410	1,156	980	16,333	6,762	5,198	17	6,931	11,869	249,731
FY2021	21,223	127,725	53,410	1,262	932	16,333	9,355	4,946	17	6,957	11,893	254,055
FY2022	21,238	127,910	53,401	1,614	827	16,333	12,349	5,342	17	6,984	11,924	257,940
FY2023	21,224	127,914	53,407	1,808	789	16,333	15,830	5,815	17	7,021	11,899	262,058
FY2024	21,222	127,915	53,411	1,857	858	16,333	18,903	6,906	17	7,054	11,898	266,375
FY2025	21,226	127,918	53,411	1,834	820	16,333	23,797	6,665	17	7,088	11,898	271,007
FY2026	21,236	127,907	53,409	1,794	763	16,333	30,089	6,349	17	7,116	11,878	276,891
FY2027	21,212	127,914	53,407	1,782	921	16,333	37,865	5,659	16	7,145	11,933	284,188
FY2028	21,223	127,915	53,411	1,781	885	16,333	45,545	5,714	16	7,175	11,914	291,912
FY2029	21,215	127,919	53,410	1,783	712	16,333	51,276	6,726	15	7,206	11,936	298,532
FY2030	21,219	127,909	53,412	1,790	693	16,333	57,868	7,093	16	7,234	11,897	305,465

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.15: NEM Energy (GWh) – Reference Case LRET Enforced

	Super-critical black coal	Sub-critical black coal	Sub-critical brown coal	Cogeneration	Steam gas	Hydro	CCGT	OCGT	OCGT-liquids	Biomass	Wind	Total
FY2011	21,230	97,755	54,580	262	395	16,333	7,971	877	9	-	2,484	201,897
FY2012	20,742	94,122	54,207	257	338	16,333	8,570	983	11	765	9,397	205,725
FY2013	21,078	96,085	54,218	327	367	16,333	9,142	1,204	13	1,533	10,299	210,599
FY2014	21,200	100,039	54,453	365	438	16,333	9,349	1,304	16	977	10,006	214,481

FY2015	20,928	102,090	54,383	354	554	16,333	9,655	1,852	14	2,189	10,194	218,546
FY2016	21,167	103,891	54,357	1,410	608	16,333	7,821	3,437	15	3,363	11,107	223,510
FY2017	21,192	106,216	54,286	1,496	681	16,333	7,725	4,027	16	4,613	13,330	229,915
FY2018	21,217	116,508	53,163	631	624	16,333	3,183	3,731	17	5,393	16,553	237,353
FY2019	21,243	118,159	53,310	725	731	16,333	3,377	4,514	17	6,160	19,706	244,277
FY2020	21,237	117,879	52,873	787	678	16,333	3,935	4,363	17	6,930	24,506	249,537
FY2021	21,241	120,337	53,374	801	747	16,333	4,564	4,882	17	6,985	24,494	253,776
FY2022	21,238	122,887	53,406	923	735	16,333	5,507	5,281	17	7,040	24,532	257,899
FY2023	21,214	125,439	53,412	1,189	731	16,333	6,222	6,044	16	7,083	24,505	262,189
FY2024	21,217	127,111	53,408	1,343	772	16,333	7,578	7,097	17	7,131	24,550	266,559
FY2025	21,201	127,872	53,409	1,436	856	16,333	11,561	6,870	17	7,189	24,521	271,265
FY2026	21,212	127,905	53,412	1,578	788	16,333	17,708	6,667	16	7,230	24,507	277,357
FY2027	21,226	127,913	53,412	1,785	831	16,333	25,117	6,180	17	7,272	24,488	284,574
FY2028	21,196	127,909	53,412	1,777	669	16,333	32,689	6,350	17	7,331	24,487	292,171
FY2029	21,204	127,909	53,405	1,786	656	16,333	38,382	7,038	17	7,383	24,513	298,626
FY2030	21,227	127,909	53,404	1,780	648	16,333	44,652	7,490	16	7,435	24,532	305,426

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.16: SWIS Energy (GWh) – Reference Case

	Black coal	Cogeneration	CCGT	OCGT	OCGT-liquids	Biomass+other	Wind	Total
FY2011	12,019	3,077	2,136	897	1	75	740	18,944

FY2012	11,805	3,019	1,620	1,273	-	75	1,529	19,321
FY2013	13,155	3,021	1,414	1,349	0	75	2,027	21,041
FY2014	13,431	3,040	1,772	1,661	-	75	2,027	22,006
FY2015	13,581	3,084	2,059	1,652	-	75	2,027	22,478
FY2016	13,727	3,097	2,004	2,070	-	75	2,027	22,999
FY2017	13,847	3,394	2,521	1,920	-	75	2,027	23,785
FY2018	13,950	3,943	1,839	2,384	-	75	2,027	24,219
FY2019	14,065	3,964	2,108	2,391	-	75	2,027	24,630
FY2020	13,962	3,901	2,990	2,068	-	75	2,027	25,024
FY2021	14,060	3,970	3,130	2,161	-	75	2,027	25,424
FY2022	14,105	3,990	3,195	2,272	-	240	2,027	25,830
FY2023	14,156	4,033	3,009	2,707	-	309	2,027	26,242
FY2024	14,188	4,109	3,332	2,696	-	309	2,027	26,661
FY2025	14,123	4,016	3,914	2,698	-	309	2,027	27,087
FY2026	14,094	3,939	4,958	2,193	-	309	2,027	27,520
FY2027	14,100	3,948	5,651	1,925	-	309	2,027	27,960
FY2028	14,090	3,950	6,176	1,854	-	309	2,027	28,407
FY2029	14,082	3,952	6,679	1,812	-	309	2,027	28,861
FY2030	14,073	3,880	7,092	1,940	-	309	2,027	29,322

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.17: NEM Energy (GWh) – Counterfactual Case

	Super-critical black coal	Sub-critical black coal	Sub-critical brown coal	Cogeneration	Steam gas	Hydro	CCGT	OCGT	OCGT-liquids	Wind	Total
FY2011	21,230	97,756	54,580	262	395	16,333	7,971	877	9	2,483	201,897
FY2012	21,223	100,748	54,587	276	439	16,333	8,709	1,030	12	2,663	206,020
FY2013	21,230	104,567	54,604	362	491	16,333	9,351	1,300	14	2,663	210,915
FY2014	21,224	107,982	54,625	414	579	16,333	9,388	1,536	16	2,663	214,762
FY2015	21,224	110,983	54,663	448	806	16,333	9,597	2,251	19	2,663	218,989
FY2016	21,237	115,037	54,731	1,180	955	16,333	8,117	3,864	17	2,663	224,136
FY2017	21,202	120,231	54,941	1,549	1,264	16,333	8,079	4,421	17	2,663	230,701
FY2018	21,194	127,336	53,411	1,115	1,197	16,333	8,962	5,795	17	2,664	238,023
FY2019	21,200	127,900	53,409	1,492	1,336	16,333	13,016	7,474	18	2,663	244,845
FY2020	21,229	127,920	53,406	1,721	1,213	16,333	19,191	6,456	17	2,663	250,149
FY2021	21,224	127,908	53,401	1,881	1,194	16,333	23,685	6,006	17	2,664	254,312
FY2022	21,190	127,914	53,407	1,881	1,094	16,333	27,772	5,905	17	2,664	258,178
FY2023	21,218	127,918	53,407	1,877	1,026	16,333	31,964	5,869	17	2,664	262,293
FY2024	21,221	127,913	53,411	1,885	1,178	16,333	35,436	6,538	17	2,664	266,595
FY2025	21,224	127,908	53,414	1,875	935	16,333	40,164	6,482	17	2,664	271,014
FY2026	21,246	127,914	53,400	1,827	892	16,333	46,608	6,113	16	2,664	277,015
FY2027	21,227	127,917	53,411	1,784	1,042	16,333	54,407	5,535	16	2,664	284,337

FY2028	21,218	127,914	53,412	1,784	986	16,333	62,534	5,287	15	2,664	292,146
FY2029	21,211	127,919	53,405	1,789	735	16,333	68,874	5,820	15	2,664	298,766
FY2030	21,226	127,910	53,409	1,781	698	16,333	75,563	6,089	15	2,663	305,687

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.18: NEM Energy (GWh) – Carbon Price Scenario 1

	Super-critical black coal	Sub-critical black coal	Sub-critical brown coal	Cogeneration	Steam gas	Hydro	CCGT	OCGT	OCGT-liquids	Biomass	Wind	Total
FY2011	21,220	96,810	54,531	258	379	16,333	7,909	853	9	-	2,484	200,787
FY2012	20,286	90,876	50,578	328	256	16,333	12,953	705	9	770	9,381	202,476
FY2013	20,873	92,961	50,090	367	283	16,333	13,410	1,036	12	1,531	10,315	207,211
FY2014	20,920	95,102	51,975	487	334	16,333	11,831	1,344	14	2,304	10,285	210,929
FY2015	20,967	96,771	51,927	593	463	16,333	12,170	1,792	18	3,077	10,826	214,939
FY2016	20,961	99,041	52,159	738	519	16,333	11,942	2,544	16	3,846	11,664	219,763
FY2017	21,002	102,473	51,726	1,230	615	16,333	11,554	2,912	16	4,625	13,374	225,861
FY2018	21,168	107,913	51,152	1,058	474	16,333	9,277	3,716	16	5,384	16,556	233,048
FY2019	21,184	108,167	52,124	1,149	486	16,333	9,917	4,393	17	6,161	19,708	239,639
FY2020	21,208	109,447	51,179	1,346	486	16,333	9,252	3,980	17	6,929	24,520	244,697
FY2021	21,213	110,242	52,369	1,324	535	16,333	10,797	4,264	17	6,986	24,511	248,592
FY2022	21,173	110,221	53,271	1,209	556	16,333	13,654	4,294	17	7,030	24,529	252,288
FY2023	21,131	109,783	53,328	1,150	537	16,333	17,645	4,599	17	7,085	24,497	256,105

FY2024	20,908	109,797	53,319	1,219	533	16,333	20,792	5,270	16	7,288	24,539	260,014
FY2025	20,786	107,592	53,275	1,140	526	16,333	28,097	4,928	16	7,289	24,549	264,531
FY2026	20,808	105,983	52,343	1,106	529	16,333	36,664	4,680	15	7,281	24,534	270,276
FY2027	20,802	106,175	51,147	1,359	517	16,333	44,583	4,023	14	7,853	24,519	277,326
FY2028	20,619	105,970	49,452	1,085	505	16,333	53,672	3,831	13	8,626	24,554	284,661
FY2029	20,618	103,953	49,256	1,044	453	16,333	61,208	4,181	13	9,295	24,487	290,842
FY2030	20,552	102,930	47,014	1,054	426	16,333	70,574	4,423	13	9,295	24,589	297,203

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.19: NEM Energy (GWh) – Carbon Price Scenario 2

	Super-critical black coal	Sub-critical black coal	Sub-critical brown coal	Cogeneration	Steam gas	Hydro	CCGT	OCGT	OCGT-liquids	Biomass	Wind	Total
FY2011	21,220	96,810	54,531	258	379	16,333	7,909	853	9	-	2,484	200,787
FY2012	20,458	90,672	50,259	333	251	16,333	13,243	775	9	770	9,381	202,484
FY2013	20,859	93,078	49,607	423	276	16,333	13,700	1,100	12	1,541	10,271	207,202
FY2014	20,841	95,503	51,374	718	342	16,333	11,799	1,374	15	2,304	10,298	210,902
FY2015	20,750	97,297	51,708	634	434	16,333	12,105	1,870	18	3,072	10,765	214,988
FY2016	20,724	99,533	51,995	665	499	16,333	11,955	2,606	17	3,846	11,584	219,758
FY2017	20,920	102,543	51,711	1,107	620	16,333	11,645	3,008	16	4,626	13,355	225,886
FY2018	21,171	107,388	51,133	1,121	468	16,333	9,798	3,697	16	5,384	16,548	233,057
FY2019	21,184	107,431	52,087	1,179	490	16,333	10,510	4,494	17	6,162	19,710	239,597

FY2020	20,936	104,784	51,101	1,220	483	16,333	14,973	3,391	16	6,934	24,506	244,677
FY2021	21,211	106,899	52,255	1,245	512	16,333	14,932	3,667	16	6,981	24,524	248,576
FY2022	20,692	105,921	52,281	1,088	511	16,333	20,248	3,454	16	7,253	24,505	252,304
FY2023	20,599	105,654	51,422	1,076	479	16,333	24,604	3,673	16	7,754	24,534	256,144
FY2024	20,426	106,156	51,327	1,128	491	16,333	26,929	4,219	17	8,523	24,469	260,019
FY2025	20,336	103,547	49,548	1,040	475	16,333	36,516	3,688	15	8,528	24,514	264,540
FY2026	20,260	100,637	48,222	1,031	455	16,333	46,780	3,625	16	8,529	24,487	270,374
FY2027	20,205	100,339	46,908	1,366	459	16,333	55,033	3,351	14	9,096	24,522	277,627
FY2028	20,162	99,023	44,016	1,329	485	16,333	66,184	3,152	13	9,733	24,527	284,958
FY2029	20,013	97,125	43,599	761	381	16,333	75,011	3,368	13	10,015	24,494	291,114
FY2030	19,597	92,327	42,899	732	357	16,333	86,884	3,212	13	10,034	24,990	297,377

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.20: SWIS Energy (GWh) – Carbon Case

	Black coal	Cogeneration	CCGT	OCGT	OCGT-liquids	Biomass+other	Wind	Total
FY2011	12,019	3,077	2,136	897	1	75	740	18,944
FY2012	8,659	3,403	3,712	1,943	-	75	1,529	19,321
FY2013	9,790	3,461	3,657	2,031	0	75	2,027	21,041
FY2014	10,344	3,562	3,699	2,299	-	75	2,027	22,006
FY2015	10,604	3,577	3,803	2,392	-	75	2,027	22,478
FY2016	10,816	3,600	3,832	2,649	-	75	2,027	22,999

FY2017	11,848	3,466	3,149	2,432	-	863	2,027	23,785
FY2018	13,453	3,887	1,719	1,966	-	863	2,330	24,219
FY2019	13,346	3,858	1,670	1,849	-	863	3,043	24,630
FY2020	13,035	3,832	1,327	1,637	-	863	4,330	25,024
FY2021	12,822	3,858	1,092	1,631	-	863	5,158	25,424
FY2022	12,847	3,858	1,262	1,537	-	863	5,464	25,830
FY2023	13,012	3,858	1,114	1,931	-	863	5,464	26,242
FY2024	13,171	3,858	1,498	1,808	-	863	5,464	26,661
FY2025	11,396	3,795	937	1,327	-	863	8,768	27,087
FY2026	11,376	3,793	1,338	1,382	-	863	8,768	27,520
FY2027	11,204	3,793	1,825	1,387	-	863	8,887	27,960
FY2028	10,631	3,778	1,830	1,391	-	863	9,914	28,407
FY2029	10,378	3,767	2,673	1,266	-	863	9,914	28,861
FY2030	9,577	3,755	3,797	1,416	-	862	9,914	29,322

Note: Data represents financial years (eg, FY2011 is 2011/12)

NERA Economic Consulting
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Tel: +61 2 8864 6500
Fax: +61 2 8864 6549
www.nera.com

Oakley Greenwood
GPO Box 4345
Melbourne VIC 3001
Tel: +61 3 9486 8097
Fax: +61 3 8080 0760
www.oakleygreenwood.com.au

NERA Australia Pty Ltd, ABN 34 092 959 665