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Submissions
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Renewable Energy Target Review – Issues Paper

TRUenergy welcomes the opportunity to provide comments on the Renewable Energy Target (RET) Review – Issues Paper (Review) published by the Climate Change Authority (CCA).

TRUenergy is one of Australia's largest energy companies, providing gas and electricity supply to over 2.7 million household and business customers. TRUenergy owns and operates a multi-billion dollar portfolio of energy generation and storage facilities across Australia including coal, gas and wind assets. TRUenergy is committed to developing low and zero emission energy generation technologies across a range of clean energy initiatives.

Overview

TRUenergy supports a 20% Renewable Energy Target by 2020 and has made significant investments in renewable energy under the policy.

The RET provides a certificate based subsidy to renewable energy technologies, which allows them to be competitive with non-renewable technologies in meeting demand growth or replacing retirements from the existing fleet of generators.

The current RET was established when strong growth in demand for energy was projected. Demand forecasts have now decreased significantly such that the current scheme design would amount to an effective 26 per cent target by 2020. Continuation of the scheme in its current form would impose unnecessary costs on customers through less productive use of capital. Analysis commissioned from ACIL Tasman estimates that the RET would provide a nominal subsidy of $53.3 billion over the life of the scheme; this subsidy increases the price of electricity for end users.

Leaving the scheme unchanged would also force increasing volumes of new renewable energy into an already oversupplied market placing greater risk on the stability of the underlying energy market.

TRUenergy considers that the significant variation in forecast demand growth highlights the need to build greater flexibility into the RET scheme. If forecast demand growth recovers, then this flexibility would also support increasing the targets – perhaps even beyond the current level. The challenge is to achieve the original policy intent while avoiding unnecessary costs on customers and providing an adequate level of certainty for investors. In reviewing the RET scheme, the CCA must also be aware of the impact its decisions will have on the broader energy market and investors across the whole industry, not just those investing in renewable technologies.

In this submission we set out our approach to achieving a "real 20% by 2020", as well as addressing other issues raised by the review. Based on analysis by ACIL Tasman, achieving a "real 20% by 2020" could reduce the subsidy to $28.1 billion – a reduction of $25 billion – which would almost halve the total cost of the scheme in 2020 for an average customer. Importantly, the proposed changes to the RET would not change Australia's contribution to climate change abatement – it would only change the composition of abatement.

The rationale and effectiveness of the RET

Innovation in low to zero emissions energy generation technology will, to a large extent, determine society's ability to reduce emissions and the cost at which such reductions can be achieved over the longer term. TRUenergy has long supported the Australian Government's "20 per cent by 2020" policy commitment on the basis that the rate and extent of innovation in these technologies can be substantially enhanced by judicious Government support.

The RET is an important component in the overall framework to encourage investment in low to zero emission energy generation technologies. Notwithstanding the significant changes to RET policy over the last decade, it has provided an overarching framework for renewable energy deployment.

Under this framework, TRUenergy has become one of Australia's leading investors in renewable energy. In 2011 TRUenergy expanded its renewable energy portfolio through its acquisition of Waterloo[1] and a 50 percent share of the Cathedral Rocks[2] wind farms. Since then TRUenergy has also been a driving force in supporting independent developers of commercially viable wind projects through agreements with a variety of projects across New South Wales and Victoria including the 107MW Boco Rocks and 108MW Taralga wind projects.

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[1] The Waterloo wind farm is located near the Clare Valley in South Australia, about 30 km south east of the township of Clare and 100 km north of Adelaide. The Waterloo wind farm comprises thirty-seven wind turbines, with a total maximum generating capacity of 111 MW. Waterloo began official operation on 3 October 2010 and will produce enough green energy to power more than 46,000 homes over 20 years.

[2] The Cathedral Rocks wind farm is a joint venture project between TRUenergy and Spanish renewable energy company, Acciona Energy. Cathedral Rocks is a remote coastal area near the southern tip of the Eyre Peninsula in South Australia, approximately 30 km south west of Port Lincoln. Cathedral Rocks wind farm has a generating capacity of 66MW and consists of 33 wind turbines. Cathedral Rocks became fully operational in May 2007.

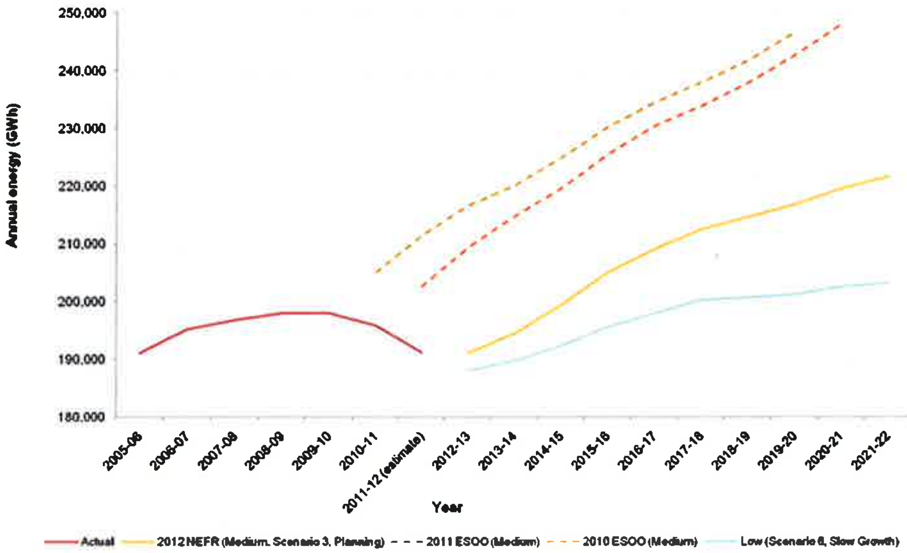
Looking to the future, TRUenergy remains committed to the development of renewable energy technologies and is currently managing a number of new wind farm proposals, which are at different stages of development. TRUenergy is also proposing the development of a large-scale solar power station near Mildura in Victoria using solar photovoltaic (PV) technology and will continue to support a range of other independent developers of renewable projects where they have been commercially developed and can compete with the alternative opportunities that exist.

Context for the review

The CCA's first review of the RET is particularly timely for three key reasons:

1. The Australian Energy Market Operator (AEMO)[3] recently forecast a fundamental reduction in energy, which is significantly below that of previous years, as shown in the chart below. Retaining the current targets for the RET and allowing the SRES to continue uncapped is likely to result in an effective 26% RET by 2020, overshooting the original policy intent of 20% renewables;

NEM Energy Forecasts



Source: AEMO 2012 National Electricity Forecasting Report, 2011 ESOO & 2010 ESOO

2. There is a renewed policy focus, at both State and Federal levels, on the recent and expected future contributors to rising electricity prices (e.g. Senate Select Committee on Electricity Prices);

3. The recent implementation of the package of Clean Energy Future policy measures which establish a price on carbon and support innovation within the renewable energy industry.

[3] AEMO, 2012 *National Electricity Forecast Report*, June 2012

TRUenergy's position

Given this context, the central consideration for the Review should be addressing this fundamental downward shift in energy demand. It is TRUenergy's strong contention that given the significant changes in demand forecasts, changes are also required to the scheme to ensure it is a "real 20 per cent by 2020" target. Failure to make such changes, under current demand forecasts, will lead to a significant overshooting of the "20 per cent by 2020". Our reasons for this position are as follows:

Achieving the original target

The intention behind the design of the RET mechanism was to achieve a proportional target. "Hard" targets were used for administrative and practical convenience during policy development. However, recent developments in energy markets have led to significant changes in energy demand and forecasts. Therefore, changes to the RET design are required to restore the original target.

Alleviating pressure on energy prices

Final energy prices have increased substantially in the last few years. This has exacerbated cost of living pressures for many in the community and increased input costs for business.

Upward pressure on energy prices is being driven by several factors including, but not limited to, the cost of renewable energy subsidies. The RET increases energy costs through a number of channels, which would be partly alleviated by moving to a "real 20% by 2020" target.

First, there is the direct cost of the subsidy, which flows through to end user bills. In order to explore this issue, TRUenergy engaged ACIL Tasman[4] to provide analysis examining the impact of the current and a possible variant of the Renewable Energy Target (RET) legislation. The report entitled "Achieving a 20% RET" has been attached to this submission. The report considered two scenarios:

- A Base case outlook that reflects the legislated fixed GWh targets under the Large-scale Renewable Energy Target (LRET) and the uncapped Small-scale Renewable Energy Scheme (SRES).
- A 'Real 20%' LRET in which the fixed GWh targets are reduced such that it reached 20% of anticipated liable demand by 2020.

The analysis found that the RET in its current form would provide a nominal subsidy of $53.3 billion over the life of the scheme while a 'Real 20%' scenario, based on the current outlook, would only cost $28.1 billion. In moving from the Base case outlook to the 'Real 20%' scenario, the analysis also found over the longer term the amount and timing of new entrant fossil fuelled capacity would adjust such that the wholesale market outcomes would likely remain similar. However in the short term across both scenarios

[4] ACIL Tasman report for TRUenergy, *Achieving a 20% RET: Costs of current legislation and possible modifications*, 5 September 2012.

wholesale prices were expected to remain relatively flat with a slight increase under the 'Real 20% Scenario'.

Second, renewable support policies have an impact on energy sector productivity, which feeds into prices. Much of the recent price increases in electricity can be attributed to declines in productivity across the sector. In a recent report the Productivity Commission highlighted the likelihood of a continuing trend in declining Multi-Factor Productivity (MFP):

> "The size of the negative effect on measured MFP due to the growth in renewable power sources is likely to have been small, but will have been increasing over time. Moreover it will continue to grow into the future as more renewables (particularly wind power) are brought into the system under the RET scheme. More broadly, given these cost differentials, until the energy sector completes its ongoing process of structural adjustment in response to climate change policies (current and future), further downward pressure on measured productivity in the sector can be anticipated." [5]

In the 2012 Electricity Statement of Opportunities (ESOO),[6] AEMO presents the current level of contribution towards meeting peak demand from renewable technologies such as wind and PV. Wind farm contribution factors range between 2.2% in NSW and 8.3% in South Australia of capacity, while rooftop PV varies between 28% in Queensland and 38% in South Australia of capacity. Introducing generation at times of the day when demand growth is low contributes to the underutilisation of the existing generation fleet.

Alleviating pressure on the energy market

In the 2012 ESOO, AEMO reports minimal need for new investment in generation prior to 2020 to meet the requirements of peak demand[7]. AEMO also reports that "average prices have been falling since 2006–07, with most regions seeing lower average prices in 2011–12 than any year since 2002–03"[8] . The encouragement of new entry into an oversupplied market is expected to result in the continuation of low average prices and the displacement of existing generation.

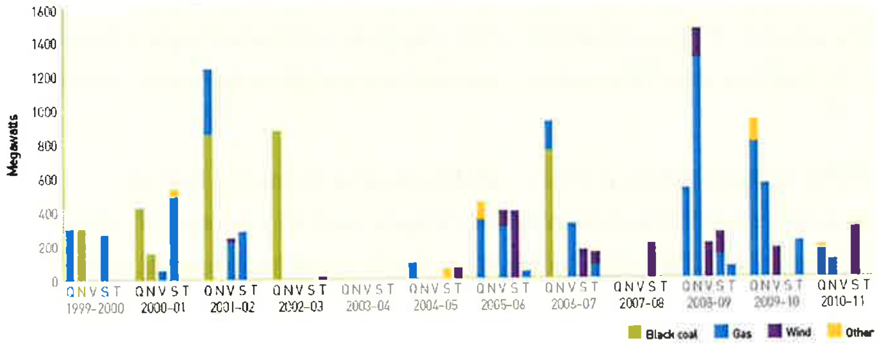
This issue was examined in the modelling results provided by ACIL Tasman, revealing that much of the additional wind built for the Base case outlook had displaced existing generation with minimal impact on the timing of non-renewable new entrants. This outcome is largely driven by the flat energy growth across the National Electricity Market (NEM). In the short term, this will affect the financial viability of many

[5] Productivity Commission Staff Working Paper, *Productivity in Electricity, Gas and Water: Measurement and Interpretation*, April 2012, pp 60-61.
[6] Australian Energy Market Operator, *2012 Electricity Statement Of Opportunities For the National Electricity Market*, August 2012, pp 2-8 to 2-9
[7] Australian Energy Market Operator, *2012 Electricity Statement Of Opportunities For the National Electricity Market*, August 2012, p 2-2
[8] Australian Energy Market Operator, *2012 Electricity Statement Of Opportunities For the National Electricity Market*, August 2012, p 2-18

generators and will continue to contribute to declining productivity in the industry identified in a recent report released by the Productivity Commission.[9]

In reviewing the value of retaining the current fixed targets the CCA must also consider the impact its decisions will have on the broader energy market and investors across the entire industry, not just those investing in renewable technologies. In the State of the Energy Market 2011, the AER highlights the significance of non-renewable investment in the National Electricity Market since 1999/00. The default position of retaining the current fixed targets increases the burden on investors in other forms of generation by sheltering renewable developers from market risk (energy volume variation) and going beyond the policy intent of balancing out competitive positions between technologies.

Annual investment in registered generation capacity



Q, Queensland; N, New South Wales; V, Victoria; S, South Australia; T, Tasmania.
Note: Data are gross investment estimates that do not account for decommissioned plant.
Sources: AEMO; AER.

Source: AER, *State of the Energy Market 2011 Figure 1.13 page 43*

Greenhouse neutrality

As Australia's total net emissions are determined under the Clean Energy Future policy package, there **would be no change in Australia's contribution to climate change abatement** from an adjustment to the RET design. There would only be change in the composition of abatement.

Developments in greenhouse policy

The establishment of the Clean Energy Finance Corporation (CEFC) and the Australian Renewable Energy Agency (ARENA) are expected to provide additional support for low to zero emissions generation technologies with a greater ability to diversify across technology types (compared to the RET).

Policy stability versus public benefits of change

One factor for the Review to consider is the tradeoff between maintaining policy stability and reform to achieve public benefits.

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[9] Productivity Commission Staff Working Paper, *Productivity in Electricity, Gas and Water: Measurement and Interpretation*, April 2012.

As with all policy frameworks designed to drive market-based outcomes, 'stability' and 'certainty' of the rules are important ingredients to achieving effective and efficient outcomes. For the most part investors respond best to predictable policy circumstances while excessive policy unpredictability manifests as a cost of doing business, which is ultimately reflected in final energy prices paid by consumers.

In a written submission to the "COAG Review of Specific RET Issues" TRUenergy cautioned policy-makers with regard to making unjustified adjustments to RET policy settings:

> "... while it is clearly the role of government to adjust policy settings from time to time, the case for these adjustments can only be made if they are clearly and demonstrably in the public interest. That is, the public benefits of an adjustment are greater than the collateral damage caused from policy uncertainty and that it is not simply the case that the adjustment shields some market participants from short term fluctuations in market fundamentals."[10]

However, in the current environment of significantly lower than forecast demand and pressure from rising electricity prices, we consider that the public benefits of an adjustment to the RET are warranted. However, in order to maintain policy stability, the proposal from TRUenergy avoids retrospective changes and provides a similar quality of forward information that is provided to investors in the non-renewable sector.

An approach for implementing a "real 20% by 2020" target

In this section we set out our preliminary, preferred approach to implementing a real 20% target. We would welcome the opportunity to work with the CCA in refining this approach.

TRUenergy's preferred policy response would be to re-combine the LRET and SRES targets into a single scheme and set an adjustable target of 20 per cent that reflects actual total energy demand in 2020.

However, given the implicit subsidies provided through the structure of network tariffs, there is not currently a level playing field between large and small scale technologies. Without a 'level playing field' recombining the LRET and SRES would lead to an inefficient balance between large and small scale deployment under a combined, single scheme approach – likely resulting in limited investment in lower-cost large scale projects. However, the complexities involved in attempting to 'level the playing field' between large and small scale technologies are prohibitive (and should be addressed as part of a broader energy market reform process).

Consequently, TRUenergy's recommended approach is to maintain the separation between the LRET and SRES.

However, to ensure a "real 20 per cent by 2020" is achieved in aggregate, the RET should be defined as the sum of the SRES and LRET targets (after factoring in the contribution of baseline generation) and

[10] TRUenergy written submission (30 October 2009) to the Renewable Energy Sub Group Secretariat, Department of Climate Change, *'COAG Review of Specific RET Issues'*, p.2.

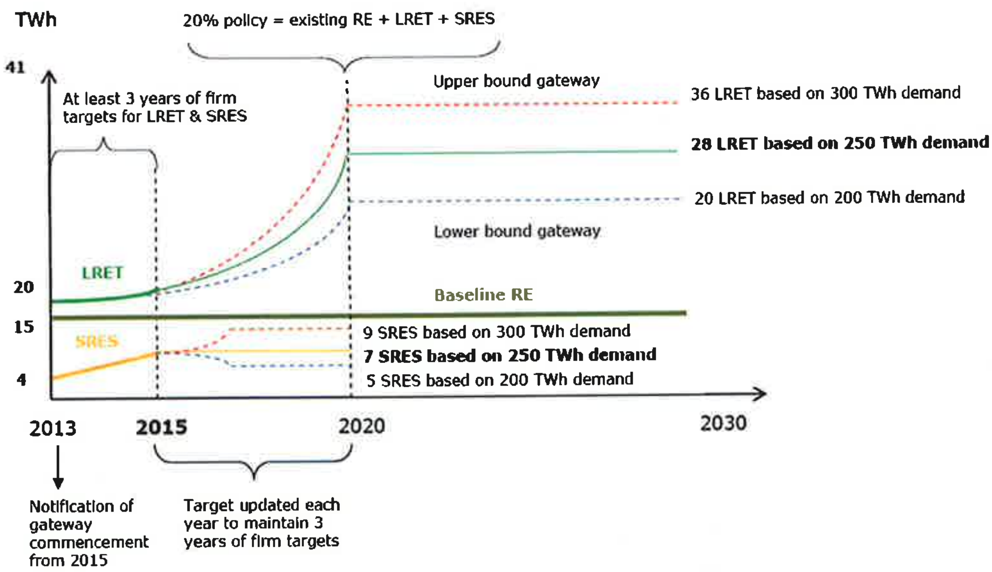
based on current demand forecasts. **To balance investor confidence with the flexibility to achieve a "real 20 per cent by 2020", three years of fixed targets should be** determined followed by an upper and lower gateway of targets based on the range of possible demand outcomes. The three years of fixed targets should then be added to annually from within the specified gateway.

In defining the specific targets for the LRET and SRES, a fixed ratio of the total renewable target would be specified. For illustrative purposes, this could be in the order of an 85/15 percent split for the LRET/SRES respectively. This would mean that the SRES would have its price determined as a function of supply and demand (as occurs under the current LRET mechanism).

Figure 1 sets out a possible approach for **establishing a "real 20% by 2020" target which** would provide a sufficient level of stability and certainty for investment while also reducing the cost of delivering the subsidy to customers over the longer term.

This approach would include establishing three years of fixed targets followed by a 'gateway' of possible targets dependent on demand forecasts. The upper and lower bound of the gateways would be fixed in 2013 for 2015 onwards. Each year an additional fixed **target would be determined, based on AEMO's** medium demand scenario, ensuring three years of fixed targets are maintained. In 2017, the fixed annual target for 2020 would be determined and this would then be held constant from 2020 to 2030.

Figure 1: Annual adjustment to maintain a "real 20% by 2020" (with Gateway)



Source: TRUenergy

Important considerations in implementing a "real 20% by 2020" target

LGC market stability

It is important that any changes to the scheme consider the potential impact on renewable energy investments that have been made under the RET.

The CCA could consider sculpting the targets in the initial years after the review (i.e. prior to 2015) to extinguish the current surplus of certificates and prevent a sudden drop in the price for LGCs. This approach is unlikely to impose increased costs to customers as the impact of the SRES should be in decline, and therefore this approach would smooth out the trajectory of total costs imposed by the RET.

Baseline generation

TRUenergy also considers that the role of baseline generation needs to be examined by the CCA. It is important to avoid a perverse outcome where maximising existing hydro generation in some years occurs at the expense of generating in other years. If the output of baseline generation is not truly providing additional generation over the long term, then compensating generation above the baseline provides an unnecessary windfall that it is only adding to the cost of meeting the scheme.

Other issues raised in the review

Clean Energy Finance Corporation–funded projects

Increasing the RET to support the activities of the CEFC would further exacerbate the cost to customers of delivering the scheme. The CEFC funding should be considered distinct from the RET as it should operate at an earlier stage of the innovation cycle for renewable technologies. The role of the CEFC should be based on supporting the diversity of renewable projects meeting the RET where there is a net benefit to the community in doing so.

Surrender and shortfall charge

The Renewable Power Percentage (RPP) and the Small-scale Technology Percentage (STP) are an effective means for setting individual entity's liable amounts.

However the setting of both the RPP and STP should be conducted by 31 December in the prior year to avoid billing and adjustment complications. Any inaccuracies that arise in establishing the RPP and STP at an earlier date can be factored into the following year.

The CCA should consider whether the date that liabilities must be acquitted (14 February) should be shifted to March to provide more time to obtain and assess relevant data.

Emissions-intensive, trade-exposed activities/Self-generator exemption

It would be beneficial if the Regulator maintained a "live" Partial Exemption Certificate (PEC) registry, updated as PECs are issued to assist us in supporting our customers.

Small-scale Renewable Energy Scheme

Providing an uncapped subsidy to any technology risks imposing an unknown level of cost on customers. As discussed earlier, TRUenergy considers that the delivery of this subsidy should be limited with respect to the overall policy intent of delivering 20% renewables by 2020. The delivery of small scale generation is occurring and continues to exceed forecasts with an estimated oversupply of 15m certificates in 2012. The large volumes of small scale technologies delivered is attributable to a range of factors which include the SRES, multipliers, retail tariffs, feed in tariffs, network pricing structures and declining technology costs.

Addition of new technologies to the SRES/Displacement technologies

The SRES forms part of the RET and therefore all new technologies should be consistent with the original policy intent of delivering renewable energy (i.e. all non-renewable technologies should be excluded). It is important that all sources of small scale renewable technologies (either generation or displacement technologies) are included to ensure the least-cost solution to delivering the policy is achieved.

Deeming

The current arrangements for deeming create a risk between the actual delivery of renewable energy from small scale projects and the policy intent. The deeming methodology for all technologies should be regularly evaluated to ensure the accuracy of the estimates and that it does not over or under compensate any manufacturer of a technology relative to the physical delivery of the product installed. Alternatively, deeming could be abolished and annual returns submitted. However, this is likely to impose significant metering costs and an administrative burden on the Regulator. It should be noted that deeming would need to be removed (or its impacts at least considered) if the SRES and the LRET were to be combined.

Solar Credits

The use of multipliers is a distortion that prevents a least-cost policy outcome. If the intent had been to kick start the solar PV industry then this may have been better delivered through clearer annual targets and market forces determining the appropriate price level at which STCs should clear. Allowing a market based approach would allow prices to adjust as technology costs reduced and therefore decrease the risk of overcompensation. The unintended impact of the multiplier approach has been additional uncertainty for market participants creating a "boom/bust" market which is clearly evident in the certificate creation cycle. There is limited economic justification for the use of multipliers in the future.

The STC Clearing House

Under the 'real 20%' proposal outline above, the, the policy rationale for the clearing house is limited; the intent was to provide price certainty for installers. However, in practice, the clearing house has had limited use to date. It is TRUenergy's belief that customers and the SRES would be better served by removing the clearing house and allowing the market to determine the appropriate price at which STCs should clear under 'real 20%' model. The CCA should also consider how the existing volume of certificates that are currently registered with the clearing house can be cleared.

Diversity of renewable energy

The RET should focus on the policy intent of delivering renewable energy at least cost to customers. Greater diversity (if there is a net public benefit) should be delivered outside of the RET (while contributing to meeting the 20% target) through the funding of research and development, providing greater availability of funds to projects which have not been proven commercially viable in Australia. The funding provided to ARENA and the CEFC should be used to achieve diversity in RET outcomes (that is, to the extent that non-wind renewable energy options would provide a net public benefit).

Review frequency

Increasing the flexibility of the scheme to deliver a "real 20% by 2020" (as described above) should enable a reduction in the scope required for future reviews. Aside from setting the annual targets, TRUenergy considers that any future reviews should be conducted at intervals no greater than every 5 years, providing a balance between the need to ensure the policy objectives are met and providing certainty through the framework to support investment. TRUenergy believes that a shift to a "real 20% by 2020" target would reduce future uncertainty because the target will deliver the original policy intent and therefore result in less chance of further changes to the structure of the target.

Conclusion

The RET is an important component in the overall framework to encourage investment in low to zero emission energy generation technologies. Notwithstanding the significant changes to RET policy over the last decade, it has provided an overarching framework for significant renewable energy deployment.

Under this framework, TRUenergy has become one of Australia's leading investors in renewable energy and into the future TRUenergy remains committed to an effective RET policy. However, continuation of the scheme in its current form would encourage investment by renewable technologies into an already oversupplied market placing greater risk on the stability of the underlying energy market and impose unnecessary costs in the order of $25 billion on customers.

The recent significant reductions in forecast demand growth highlights the need to build greater flexibility into the RET scheme. The challenge is to achieve the original policy intent whilst avoiding unnecessary costs on customers and providing an adequate level of certainty for investors. In reviewing the RET scheme, the CCA must also consider the impact its decisions will have on the whole industry, not just those investing in renewable technologies.

In this submission we set out an option to achieve a “real 20% by 2020”. Based on analysis by ACIL Tasman, achieving a “real 20% by 2020” could reduce the subsidy to $28.1 billion – a reduction of $25 billion – which would almost halve the total cost of the scheme in 2020 for an average customer. Importantly, the proposed changes to the RET would not change Australia’s contribution to climate change abatement – it would only change the composition of abatement.

The focus of TRUenergy’s proposal is not to undermine investor confidence or long term returns in delivering the projects that support the RET. The objective is to reduce the burden on customers by lowering the volumes of renewable energy required by the target, to reflect the recent reductions in energy and the original policy intent of achieving a “real 20% by 2020”.

Should you wish to discuss or clarify any of the issues raised in the submission then please feel free to contact me on 03 8628 1496.

Yours sincerely

Clare Savage
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Final report

Under Embargo until 1am 7th September 2012

Achieving a 20% RET

Costs of current legislation and possible modifications

Prepared for TRUenergy

5 September 2012

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Executive summary

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The analysis considered two scenarios:

- A Base case outlook which reflects the legislated fixed GWh targets under the Large-scale Renewable Energy Target (LRET) and the uncapped Small-scale Renewable Energy Scheme (SRES)
- A 'Real 20%' LRET in which the fixed GWh targets are reduced such that it reached 20% of anticipated liable demand by 2020.

In modelling these scenarios ACIL Tasman utilised its *PowerMark* and *RECMark* models to evaluate impacts at the wholesale level and also implications for the direct cost upon residential users.

The modelling demonstrated that modifications to the RET will have some short-term impacts upon wholesale electricity price outcomes, however the amount and timing of new entrant fossil fuelled capacity will adjust accordingly such that the wholesale market will not deviate from its equilibrium price path.

The analysis has therefore focused upon the direct costs upon electricity users resulting from the renewable energy schemes.

In its current form, the RET is a significant subsidy with an estimated total direct value of $53.3 billion (in nominal terms) within the Base case as shown in Table ES 1. Over 80% of this is associated with the LRET, where costs are anticipated to grow over time, in line with increasing fixed GWh targets. The direct costs of subsidising small-scale systems, whilst currently high due to the influence of Solar Credits multiplier, is projected to decrease over time.

The 'Real 20%' scenario which has lower GWh targets in accordance with the current demand outlook reduces the aggregate direct cost to $28.1 billion ($25.2 billion lower than the Base case). This adjustment results in the 2020 target falling to around 28,000 GWh compared with the current 41,000 GWh level. The lower target results in lower certificate prices, and a lower level of large-scale renewable deployment (wind in the NEM is around 3,300 MW lower by 2020 under this scenario).

Table ES 1 **Projected aggregate subsidies paid through RET**

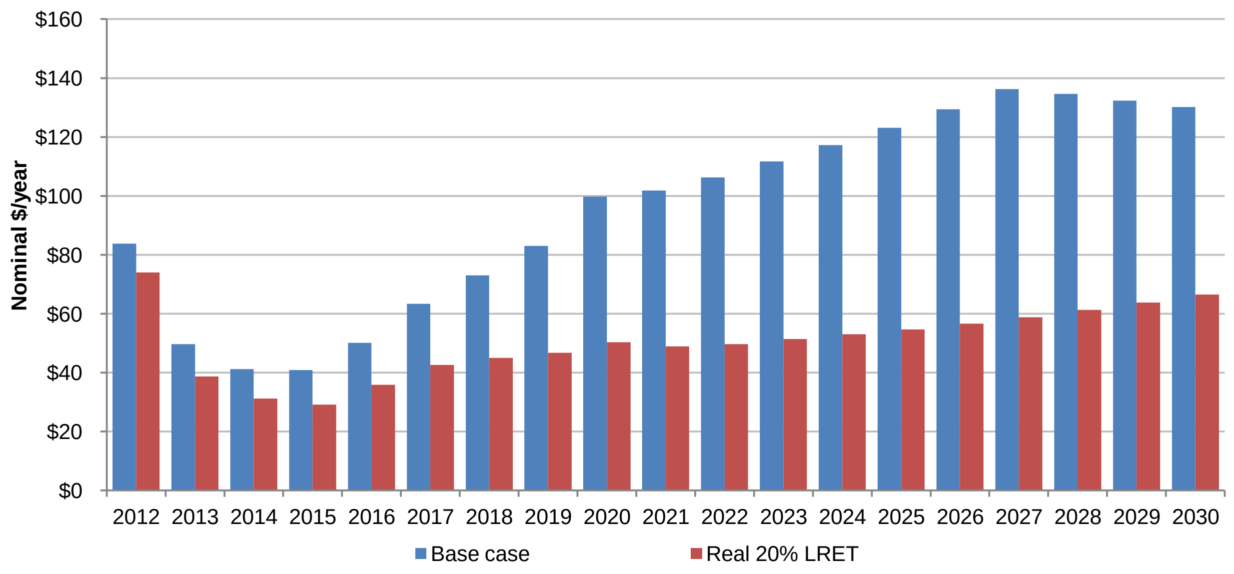
Scenario	Aggregate LRET subsidy 2012-2030	Aggregate SRES subsidy 2012-2030	Aggregate RET subsidy 2012-2030
	$ billion	$ billion	$ billion
Base case	43.2	10.1	53.3
'Real 20%' LRET	17.9	10.1	28.1

Note: Nominal dollars.
Data source: ACIL Tasman projections

Figure ES 1 shows indicative annual direct costs of the RET for a typical residential household consuming 7 MWh per annum. Scaling back obligations under the RET through the lower GWh targets has the potential to reduce pressures on retail electricity prices, whilst still maintaining the stated policy intent of 20% renewables by 2020.

In summary, the total direct cost upon households from the RET scheme under each scenario over the period 2012 to 2030 (in nominal terms) is $1,800 under the Base case and $960 under the 'Real 20%' LRET. Therefore moving from the current scheme to a Real 20% LRET is projected to save an average household a total of $840 over the period in nominal terms.

Figure ES 1 **Indicative annual individual household cost of RET: Scenario comparison**



Note: Based on household consumption of7 MWh per year; includes 10% notional energy losses; excludes GST. Nominal dollars based on assumed inflation of 2.5%. Includes both LRET and SRES costs
Data source: ACIL Tasman estimates

1 Introduction

ACIL Tasman has been engaged by TRUenergy to provide a market projections report specifically examining the impact of the current and possible variants of the Renewable Energy Target (RET) legislation.

This report presents the methodology and results of this market modelling exercise.

1.1 Scope of work

ACIL Tasman was tasked with providing a modelling report examining the two renewable scenarios set out below.

Current scheme: Base case outlook

The first scenario examines the impact of the current LRET legislation which mandates a fixed 41,000 GWh of large-scale renewable energy by 2020 combined with the existing uncapped SRES which may result in aggregate compliance rate – the combination of the Renewable Power Percentage (RPP) and Small-scale Technology Percentage (STP) – being well above 20% in 2020.[1]

A 'Real 20%' renewable target

A second scenario examines an alternative policy where support for renewables is limited to a 'Real 20%' level.

This would include a modified target for a combined LRET such that it reached 20% of anticipated liable demand by 2020. The SRES scheme would remain in its current uncapped form. Based on projections of up-take of small scale systems, this would likely results in overall renewable energy delivered to customers exceeding the 20% level.

The modelling covers the period 2012 through to 2030 and is NEM focussed only, although the modelling does include assumptions for non-NEM regions in order to calculate RPP and STP values. The results include wholesale, generation investment split by technology type, LGC/STC prices (including penalty payments), RPP/STP estimates and direct subsidy costs.

[1] It should be noted that the original expanded renewable energy target was based on an incremental 45,000 GWh of renewable energy by 2020, notionally 20% when new (45,000 GWh) was added to existing baselined generation (roughly 15,000 GWh) against anticipated 2020 Australian electricity demand of 300,000 GWh.

2 Methodology

This section provides an overview of the methodology employed within this study in estimating the impacts of the SRES/LRET upon market outcomes.

2.1 Wholesale electricity

ACIL Tasman has undertaken the wholesale electricity market modelling component using its in-house market simulation model – *PowerMark*. *PowerMark* has been developed over the past 13 years in parallel with the development of the NEM. The model is used extensively by ACIL Tasman in simulations and sensitivity analyses conducted on behalf of industry clients.

PowerMark is a complex model with many unique and valuable features. It provides insights into:

- wholesale pool price trends and volatility
- variability attributable to weather/outages and other stochastic events
- market power and implications for generator bidding behaviour
- network utilisation and generation capacity constraints
- viability of merchant plant and regional interconnections
- contract and price cap values
- timing, size and configuration of new entrant generators
- demands for coal, gas and other fuels; and
- the cost outlook for buyers of wholesale electricity.

PowerMark effectively replicates the AEMO settlement engine — SPD engine (scheduling, pricing and dispatch). This is achieved through the use of a large-scale LP-based solution incorporating features such as quadratic interconnector loss functions, unit ramp rates, network constraints and dispatchable loads. The veracity of modelled outcomes relative to the AEMO SPD has been extensively tested and exhibits an extremely close fit.

The key input parameters within any *PowerMark* simulation are:

- Energy and peak demand projections
- Existing supply including all key operational parameters for power stations down to unit level
- Greenhouse gas abatement policies such as explicit carbon pricing through the Clean Energy Future (CEF) legislation
- Non-renewable new entrant assumptions for the suite of candidate technologies assumed in the modelling
- Construction of generator offers and offer curves (bidding behaviour)

- Plant availability (planned and forced outage rates)
- Transmission interconnection assumptions.

The model has been run at an hourly resolution over the period July 2012 to December 2030. Conventional (fossil fuel) new entrants are introduced into the scenario on a commercial basis and incumbent generators are retired if net pool earnings fall below levels required to sustain fixed operating costs.

All assumptions used in the modelling are taken from publicly available or in-house information and databases maintained by ACIL Tasman.

2.2 LRET

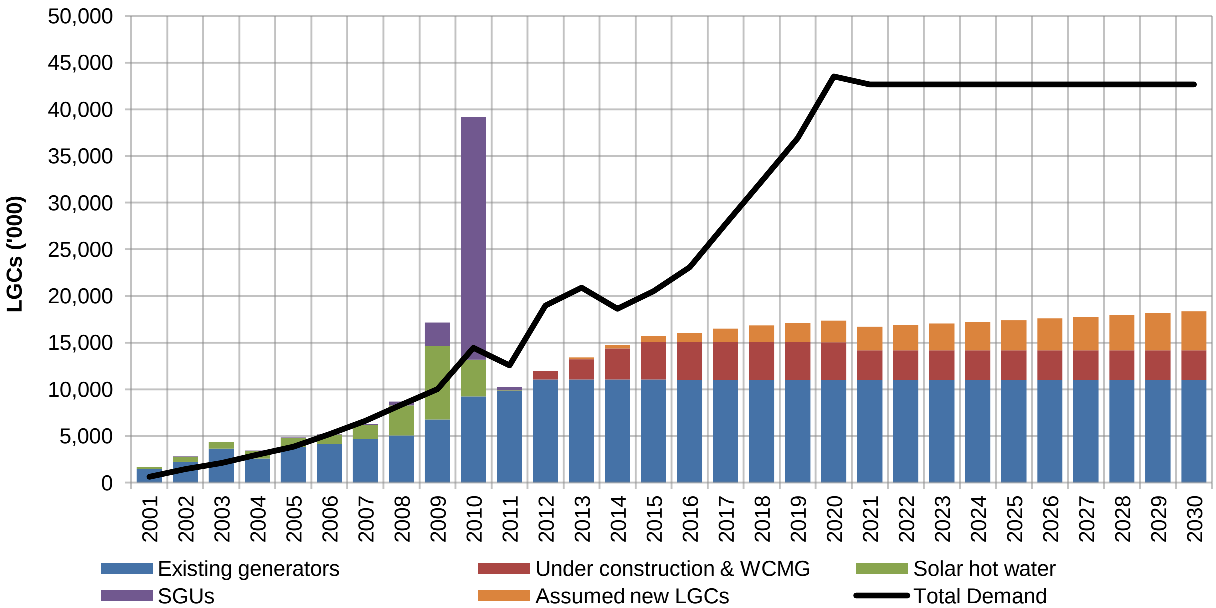
Projections of large-scale renewable development and Large-scale Generation Certificate (LGC) prices have been developed through the use of *RECMark* – ACIL Tasman's model of the LRET. The model utilises a large-scale linear programming solver with an objective function to comply with the LRET in a rational, least cost manner. It operates on an inter-temporal least cost basis, under the assumption of perfect certainty.

The model horizon covers the period from 2010 to 2060. This extends well beyond the end of the LRET (2030) in order to account for the economics of renewable plant installed within the period of the scheme, but beyond the end of the subsidy. In essence the model develops new renewable projects on a least cost basis across Australia and projects the marginal LGC price required to ensure all projects that are projected to be developed are commercially viable. In this sense the LGC price reflects the subsidy required to make the most marginally developed project just profitable over the life of the LRET scheme. The LGC price series extends through to 2030 and takes into account all inputs and constraints.

The model simulates the development and operation of new entrant plant based on technology cost settings and project specific parameters within the inputs. The model will naturally develop the lowest cost projects first, subject to any build and capacity limitations applied. Once developed, each of these new entrant projects creates LGCs over its economic life, based on its maximum capacity factor and marginal loss factor (MLF). Combined with output assumptions for existing projects, this allows results to be reported on LGC creation by technology and fuel mix.

Figure 1 shows the historical and forward-looking supply-demand balance under the LRET. *RECMark* seeks to fill the gap at least cost, taking into account the large banked certificate position. The model produces a LGC price projection and the projected level of development of wind, geothermal and utility-scale solar projects.[2]

Figure 1 **LGC supply demand balance: 2001 to 2030**



Note: Existing generators include all facilities registered within the REC Registry. WCMG = Waste Coal Mine Gas. SGUs = Small Generating Units (PV). Assumed new LGCs represent contributions from niche technologies (Landfill gas, Bagasse, Wood, Sewage Gas, and embedded solar PV above 100 kW in size) which are not explicitly modelled within RECMark. Total demand includes mandated demand under LRET, allowance for WCMG, operation of desalination plants, GreenPower and other voluntary surrenders.

Data source: ACIL Tasman analysis

To translate the aggregate LRET target for any given year into a mechanism by which individual electricity users that are liable under the scheme ('liable entities') can determine how many LGCs they must purchase and acquit, the LRET legislation requires the Clean Energy Regulator (CER) to publish a Renewable Power Percentage (RPP) for each year.

The RPP is determined ex-ante by the CER and represents the relevant year's LRET target as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year. Accordingly, the RPP also represents the percentage of any individual user's liable electricity consumption that must be acquitted through the surrender of LGCs for the relevant compliance year.

Entities that undertake eligible emissions-intensive activities may be allocated Partial Exemption Certificates (PECs), which can be used to reduce their total liability under the LRET (or passed on to a retailer making wholesale acquisitions on their behalf).

[2] The development of landfill gas, bagasse, wood, sewage gas, and embedded solar PV above 100 kW in size as assumed exogenously to the model.

Reflecting on the origins of the PEC regime from the CPRS framework, two categories of emissions-intensive activities are defined under the LRET:

- 'highly emissions-intensive' activities, attracting exemption at a 'headline' rate of 90%
- 'moderately emissions-intensive' activities attracting exemption at a 'headline' rate of 60%.

For any individual entity, LRET liability under the PEC regime is defined as the level of 'reduced acquisitions' multiplied by the RPP, where:

In this way, the existence of partial exemption certificates reduces the liability of entities undertaking EITE activities. Further, the RPP is defined in aggregate by reference to reduced acquisitions rather than relevant acquisitions as below:

This means that the existence of PECs increases the RPP by reducing the denominator of the above equation which means that the larger the exemptions, the larger the RPP. In effect some of the partial exemption is recaptured through the higher RPP from those firms with the partial exemptions (to the extent that they are not exempt), although most of the exemption is spread across non-exempt users. It is necessary to estimate both the level of relevant acquisitions and partial exemptions in any future year to estimate the likely RPP.

2.3 SRES

Outcomes under SRES comprise of two main components:

- Uptake of small-scale generation systems: solar PV and solar water heater installations, the level of which effectively sets the Small-scale Technology Percentage (STP)
- The cost of Small Technology Certificates (STCs).

The SRES supports small-scale generation through upfront deeming (15 years for PV systems and 10 years for SWH). A certificate is equivalent to 1 MWh of electricity deemed to be displaced by the installation of the system.

For this exercise we have relied upon PV installation projections undertaken by AEMO as part of the 2012 National Electricity Forecasting Report (NEFR)[3]

[3] AEMO, National Electricity Forecasting Report, June 2012

under its medium planning scenario. A proportion of these installations were assumed to be above 100 kW in size, such that they create LGCs under LRET rather than STCs under SRES.

Projections for solar water heaters were developed through a stock replacement model and drew upon previous work ACIL Tasman has completed for the AEMC in late 2011.[4]

SWH uptake is heavily affected by policy, regulatory and stock replacement drivers on top of direct economic (e.g. cost) drivers. Accordingly, we consider that a replacement stock model that captures key trends in replacement and new building SWH installations, and drivers including technology restrictions, technology options, availability of natural gas and new dwelling construction rates, provides a reasonable basis for projected up-take.

The cost of STCs is a function of supply-demand in secondary markets. While the Clean Energy Regulator operates a clearing house with a reserve price of $40/STC, to-date prices in secondary markets have been significantly below this level as certificate creation has outstripped liable entities surrender obligations (which are based on ex-ante projections). It has been assumed that forecasts of up-take become more accurate and the STC price trends toward the clearing house level by 2013. This price is held constant to 2030 at $40/STC (nominal).

Similar to the LRET, annual liability under the scheme is enabled through the specification of the Small-scale Technology Percentage (STP). However, unlike the LRET, the SRES in an uncapped scheme with the 'demand' being determined by the regulator based on projected certificate creation. It is implicitly assumed that the forecast uptake precisely equals the actual uptake. The STP therefore becomes the projected certificate creation divided by the same relevant acquisitions minus partial exemption certificates as calculated for the LRET.

[4] ACIL Tasman, *Analysis of the impact of the Small Scale Renewable Energy Scheme: Projection of retail electricity price impacts and abatement to 2020*, November 2011

3 Base case

The 'Base case' scenario is based primarily on ACIL Tasman views in consultation with TRUenergy. It is used as a reference point for the status quo.

3.1 Scenario design and key inputs

The key inputs to the Base case scenario are:

- Peak demand and energy projections as per AEMO's recent National Electricity Forecasting Report with some minor adjustments to account for additional LNG-based load in Queensland (approximately 600 MW above the AEMO forecast).
- Fuel cost projections as per ACIL Tasman internal Base case views. This includes gas market modelling which has a total of eight LNG trains developed in Queensland, with domestic prices trending toward LNG netback.
- Carbon prices which utilise the fixed prices under the current Clean Energy Future legislation until 30 June 2015, then move onto a floating price under the ETS. ACIL Tasman has used the mid-point between prices forecast by Treasury under its Core Policy case and an extrapolated CER forward curve. These carbon prices are detailed in Table 1.[5]
- New entrant costs and technical parameters are per ACIL Tasman's internal database.
- The Contract for Closure (CFC) mechanism is assumed to result in the closure of the Energy Brix (195 MW) coal-fired power station in 2021. Playford is assumed to remain closed. No other stations were assumed to close under the CFC or retired on economic grounds.

Table 1 **Carbon prices assumed: Base case**

Financial Year	Base case	Core Policy	CER Forward
2012-13	23.00	23.00	5.19
2013-14	24.15	24.15	5.47
2014-15	25.40	25.40	6.05
2015-16	17.69	28.86	6.52
2016-17	18.85	30.81	6.89
2017-18	20.16	33.06	7.25
2018-19	21.53	35.40	7.65
2019-20	23.16	38.10	8.23
2020-21	25.02	41.31	8.72

[5] We note the recently announced linkage with the European emissions trading scheme from 1 July 2015.

Financial Year	Base case	Core Policy	CER Forward
2021-22	27.09	44.93	9.24
2022-23	29.32	48.85	9.80
2023-24	31.73	53.07	10.39
2024-25	34.39	57.77	11.01
2025-26	37.25	62.82	11.67
2026-27	40.31	68.24	12.37
2027-28	43.58	74.05	13.11
2028-29	47.33	80.76	13.90
2029-30	51.00	87.26	14.73

Note: Nominal \$/tonne CO_2-e

Data source: Commonwealth Treasury (Core Policy), ICE CER Forward Curve (9 July 2012) and ACIL Tasman analysis

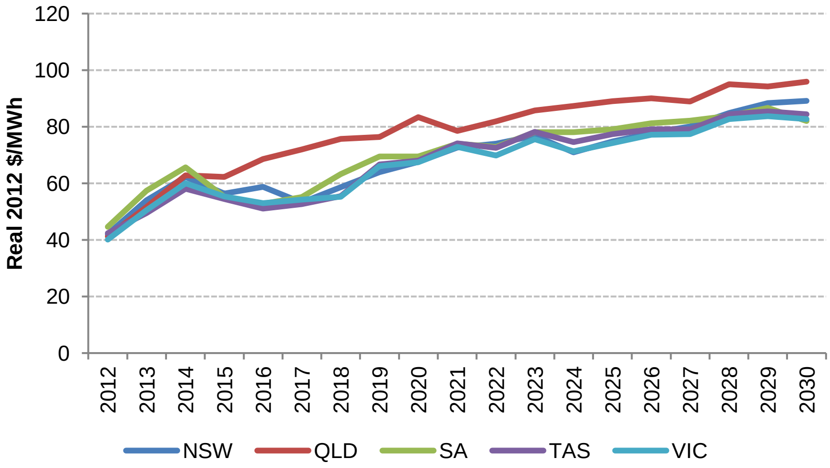
3.2 Wholesale market results

3.2.1 NEM outcomes

Figure 2 and Table 2 provide the time-weighted annual average pool price outcomes under the Base case NEM modelling. Key points from price projection are as follows:

- Wholesale prices are projected to rise strongly driven by carbon prices and increasing gas costs over the longer term.
- Prices moderate in most regions in 2016 due to the drop in carbon prices assumed in all regions except Queensland where rapid demand growth occurs stemming from CSG-LNG loads coming online.
- Development of large quantities of wind generation in the period 2014 to 2018, combined with low demand growth tend to suppress wholesale price outcomes below new entry levels in Southern States.
- In the longer-term Queensland exhibits the highest wholesale prices, due to higher wholesale gas prices.

Figure 2 **Projected NEM pool price outcomes: Base case**



Note: Time-weighted average annual prices. Year 2012 includes actual market price outcomes from January to June. Real 2012 $/MWh

Data source: ACIL Tasman PowerMark modelling, AEMO

Table 2 **Projected NEM pool price outcomes: Base case**

Calendar year	NSW	QLD	SA	TAS	VIC
2012	42.07	41.19	44.59	42.35	40.12
2013	53.99	51.57	57.38	49.48	50.51
2014	62.28	62.80	65.61	58.08	59.96
2015	56.32	62.28	55.19	54.50	55.36
2016	58.76	68.54	52.75	51.06	52.93
2017	53.22	71.91	55.08	52.60	54.27
2018	58.65	75.72	63.24	55.44	55.22
2019	63.96	76.41	69.45	66.65	66.13
2020	67.57	83.32	69.45	67.98	67.40
2021	72.68	78.54	74.00	74.10	72.88
2022	73.97	81.87	72.85	72.48	69.81
2023	76.79	85.76	78.04	78.17	75.60
2024	70.96	87.33	78.06	74.50	71.28
2025	74.75	89.01	79.12	77.33	74.26
2026	77.70	90.00	81.17	79.11	77.15
2027	80.04	88.90	82.13	79.04	77.39
2028	84.84	95.05	83.87	84.42	82.69
2029	88.29	94.21	86.68	85.37	83.71
2030	89.11	95.87	82.06	84.42	82.70
Compound growth rates (Real)					
2012 to 2020	6.1%	9.2%	5.7%	6.1%	6.7%
2020 to 2030	2.8%	1.4%	1.7%	2.2%	2.1%
2012 to 2030	4.3%	4.8%	3.4%	3.9%	4.1%

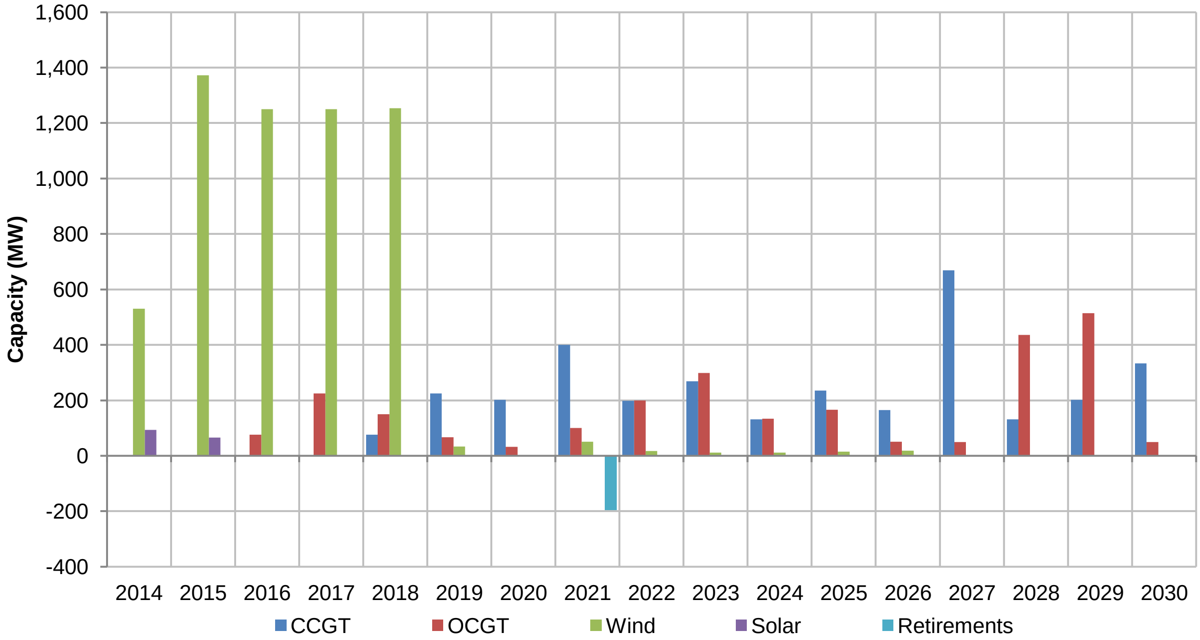
Note: Time-weighted average annual prices. Year 2012 includes actual market price outcomes from January to June. Real 2012 $/MWh

Data source: ACIL Tasman PowerMark modelling, AEMO

Figure 3 shows the new entrant and retirement profiles under the Base case for gas-fired technologies, wind, solar and incumbent power station retirements. New wind development dominates the early years of the projection, driven by the LRET subsidy. This defers the need for gas-fired generation until late in the decade.

Much of this new generation development occurs in Queensland where demand growth is the strongest of all NEM regions.

Figure 3 **NEM new entrant and retirement profile: Base case**



Note: New entrant plant introduced midway through the year will show a proportion of the total capacity in that year, with the balance in the following year.
Data source: ACIL Tasman PowerMark modelling

3.2.2 LRET outcomes

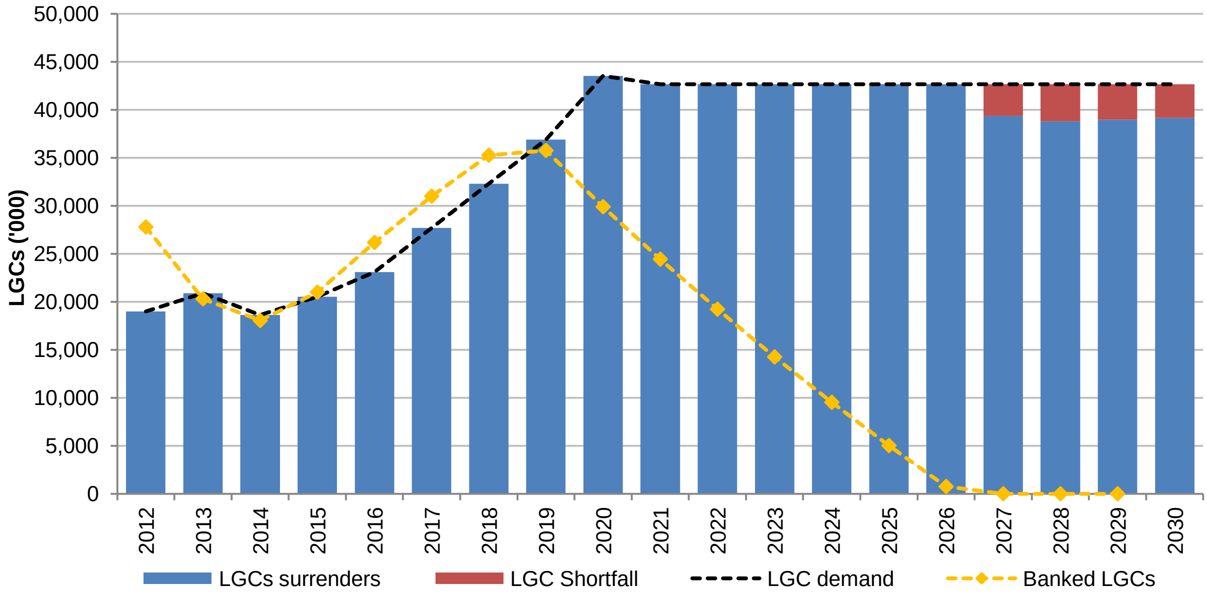
Figure 4 shows the LGC demand and annual surrenders under the scheme. New renewable developments are sufficient to meet liable entity obligations until 2027 when a shortfall against the target occurs. This implies that it is cheaper for liable entities to pay the penalty rather than pay the required subsidy for incremental renewable generation.

Figure 5 shows the aggregate LGCs created by technology and by jurisdiction over the period 2012 to 2030. In total 620 million LGCs are created which includes contributions from already existing stations.

Wind dominates new renewable development accounting for virtually all new large-scale deployment. No geothermal or utility scale solar plants (aside from those partially funded through solar flagships) are projected to be built within the modelling.

Figure 6 shows the projected LGCs price path under the Base case. As the market experiences a certificate shortfall from 2027 onward, the projected price reflects the tax-adjusted penalty price in this period.[6] The model projects a "Hotelling" type price path, where current prices at linked to the marginal 2027 price by the assumed holding cost interest rate. This gives a current projected 2012 LGC price of around $30.80/certificate.

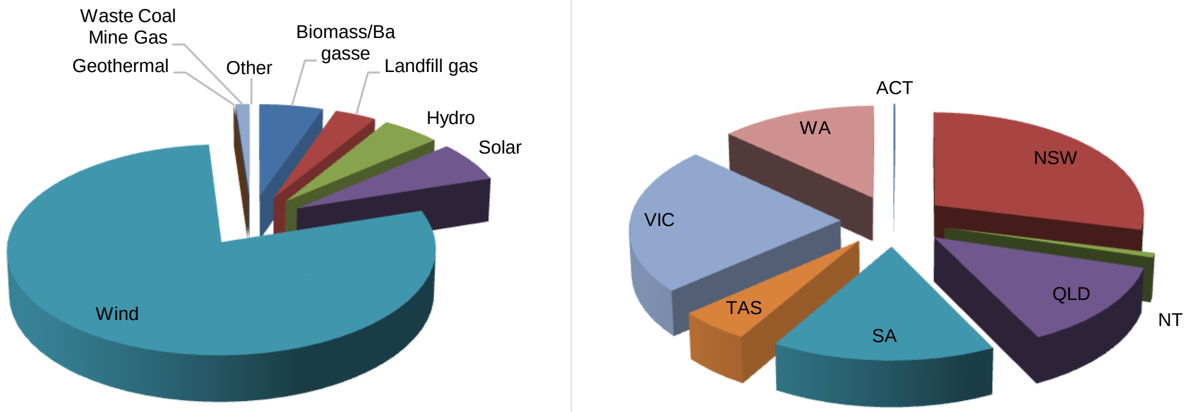
Figure 4 **LGC surrenders and banked LGCs 2012-2030: Base case**



Note: Surrendered include those to acquit obligations and voluntary surrenders. Banked LGCs are presented after that year's surrender has occurred.
Data source: ACIL Tasman RECMark modelling

[6] It should be noted that the tax-adjusted penalty price of $92.86/LGC has been used, but it is acknowledged that liable entities may pay higher prices to avoid a shortfall and the associated potential reputational damage that may accompany such an outcome.

Figure 5 **LGCs created by fuel source and by jurisdiction: Base case**

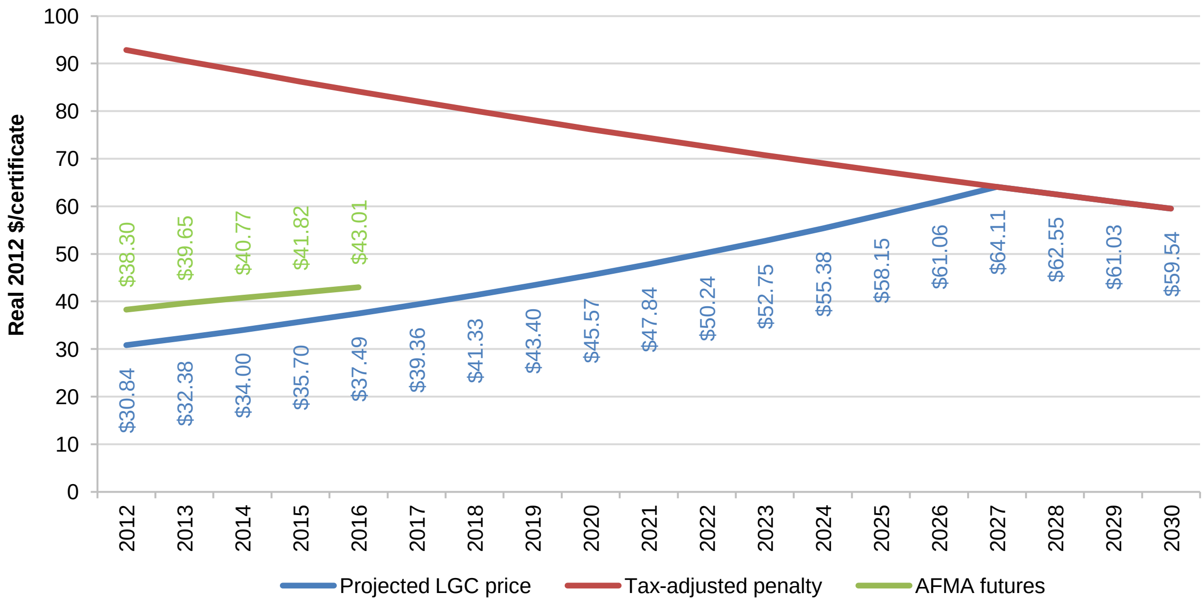


Fuel type	LGCs (million)	Share
Biomass/Bagasse	32.9	5.3%
Landfill gas	21.7	3.5%
Hydro	30.6	4.9%
Solar	39.2	6.3%
Wind	488.4	78.8%
Geothermal	0.0	0.0%
Waste Coal Mine Gas	7.3	1.2%
Other	0.0	0.0%
	620.0	100.0%

Jurisdiction	LGCs (million)	Share
ACT	0.9	0.1%
NSW	178.3	28.8%
NT	4.5	0.7%
QLD	81.0	13.1%
SA	97.7	15.8%
TAS	31.5	5.1%
VIC	144.9	23.4%
WA	81.2	13.1%
Total	620.0	100.0%

Note: Aggregate projected LGCs created 2012 to 2030. Includes LGCs created from existing accredited generators.
Data source: ACIL Tasman RECMark modelling

Figure 6 **Projected LGC prices and current futures prices: Base case**

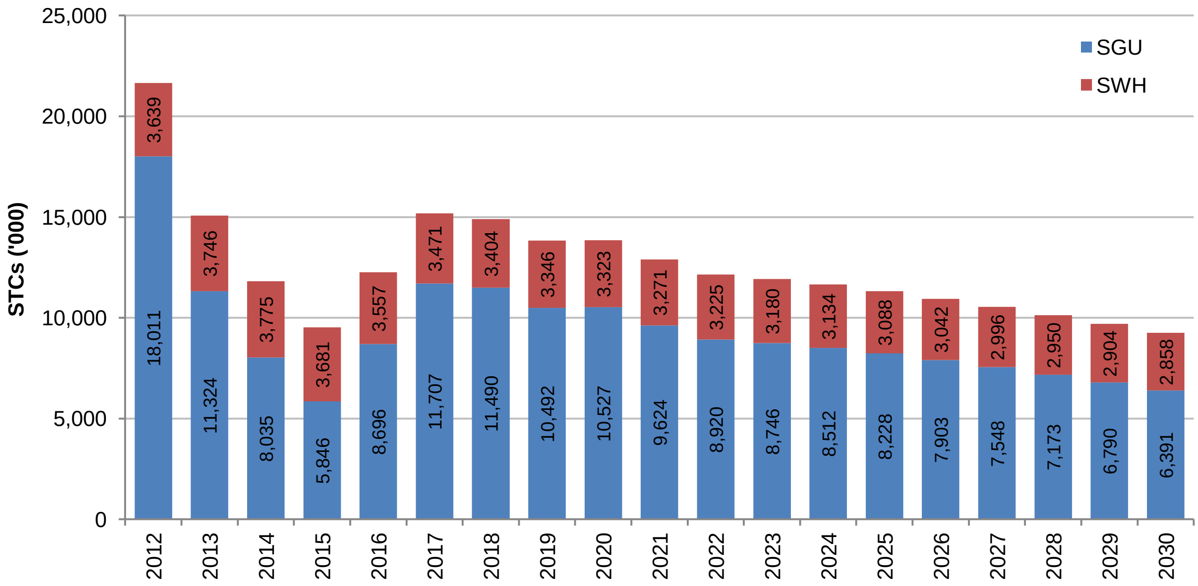


Note: AFMA futures prices are mean of all mids as at 9 August 2012, converted to Real 2012 dollars. Inflation of 2.5% used throughout. Timing of AFMA prices have not been adjusted to match RECMark timing (i.e. AFMA Cal12 is for delivery in Jan 2013; whereas RECMark 2012 price applies throughout calendar year 2012).
Data source: ACIL Tasman RECMark modelling, AFMA

3.2.3 SRES outcomes

STC creation is driven by the assumptions on PV installs (which are derived from the AEMO forecasts) and SWH uptake as shown below.

Figure 7 **Projected STC creation rates by technology: Base case**



Note: The STP for the 2012 year is 23.96% (equivalent to 44.786 million in 2012). This includes carry-over of some 23 million excess certificates from 2011. STC acquittal estimates for 2013 and 2014 have been based from the Clean Energy Regulator's non-binding estimates which were set on 30 March 2012.
Data source: ACIL Tasman analysis

Table 3 **Summary of SRES projections: Base case**

Calendar year	Relevant acquisitions	PECs	Reduced acquisitions	STC acquittal target	Projected STP	STC price
	GWh	GWh	GWh	('000)	%	$/STC
2012	210,989	28,860	182,129	44,786	23.96%	$33.65
2013	216,645	25,176	191,469	15,070	7.87%	$40.00
2014	224,232	22,858	201,374	11,810	5.86%	$40.00
2015	230,189	22,070	208,119	9,527	4.58%	$40.00
2016	234,672	22,994	211,679	12,254	5.79%	$40.00
2017	238,296	23,701	214,596	15,178	7.07%	$40.00
2018	241,108	23,559	217,548	14,894	6.85%	$40.00
2019	244,277	24,442	219,835	13,838	6.29%	$40.00
2020	247,563	25,520	222,043	13,850	6.24%	$40.00
2021	250,064	25,758	224,306	12,896	5.75%	$40.00
2022	252,201	26,025	226,176	12,146	5.37%	$40.00
2023	254,785	26,373	228,412	11,925	5.22%	$40.00
2024	257,867	26,772	231,095	11,646	5.04%	$40.00
2025	261,064	27,177	233,887	11,316	4.84%	$40.00
2026	264,158	27,568	236,590	10,945	4.63%	$40.00

Calendar year	Relevant acquisitions	PECs	Reduced acquisitions	STC acquittal target	Projected STP	STC price
	GWh	GWh	GWh	('000)	%	$/STC
2027	266,978	27,920	239,058	10,544	4.41%	$40.00
2028	269,194	28,200	240,994	10,123	4.20%	$40.00
2029	271,233	27,250	243,983	9,694	3.97%	$40.00
2030	273,421	26,303	247,118	9,250	3.74%	$40.00

Note: STC acquittal estimates for 2013 and 2014 have been based from the Clean Energy Regulator's non-binding estimates which were set on 30 March 2012.

Data source: ACIL Tasman analysis

3.3 Summary of RET costs

In aggregate over the period 2012 to 2030, the total subsidy projected to be paid under the LRET/SRES is around $53.3 billion in nominal terms as detailed in Table 4. Around 81% of this total ($43.1 billion) is associated with the LRET.

Table 4 **RET cost summary: Base case**

Calendar year	Relevant acquisitions	PECs	Reduced acquisitions	Projected RPP	Projected STP	LRET cost	SRES cost	Total RET cost
	GWh	GWh	GWh	%	%	$m	$m	$m
2012	210,989	28,860	182,129	9.15%	23.96%	514	1,469	1,983
2013	216,645	25,176	191,469	9.97%	7.87%	634	603	1,236
2014	224,232	22,858	201,374	8.42%	5.86%	605	472	1,078
2015	230,189	22,070	208,119	9.06%	4.58%	725	381	1,106
2016	234,672	22,994	211,679	10.12%	5.79%	887	490	1,377
2017	238,296	23,701	214,596	12.13%	7.07%	1,159	607	1,766
2018	241,108	23,559	217,548	14.08%	6.85%	1,468	596	2,064
2019	244,277	24,442	219,835	16.03%	6.29%	1,817	554	2,371
2020	247,563	25,520	222,043	18.85%	6.24%	2,323	554	2,877
2021	250,064	25,758	224,306	18.28%	5.75%	2,450	516	2,966
2022	252,201	26,025	226,176	18.13%	5.37%	2,637	486	3,122
2023	254,785	26,373	228,412	17.95%	5.22%	2,838	477	3,315
2024	257,867	26,772	231,095	17.74%	5.04%	3,054	466	3,520
2025	261,064	27,177	233,887	17.53%	4.84%	3,287	453	3,739
2026	264,158	27,568	236,590	17.33%	4.63%	3,537	438	3,975
2027	266,978	27,920	239,058	17.15%	4.41%	3,807	422	4,229
2028	269,194	28,200	240,994	17.01%	4.20%	3,807	405	4,212
2029	271,233	27,250	243,983	16.80%	3.97%	3,807	388	4,195
2030	273,421	26,303	247,118	16.59%	3.74%	3,807	370	4,177
Total						43,163	10,145	53,308

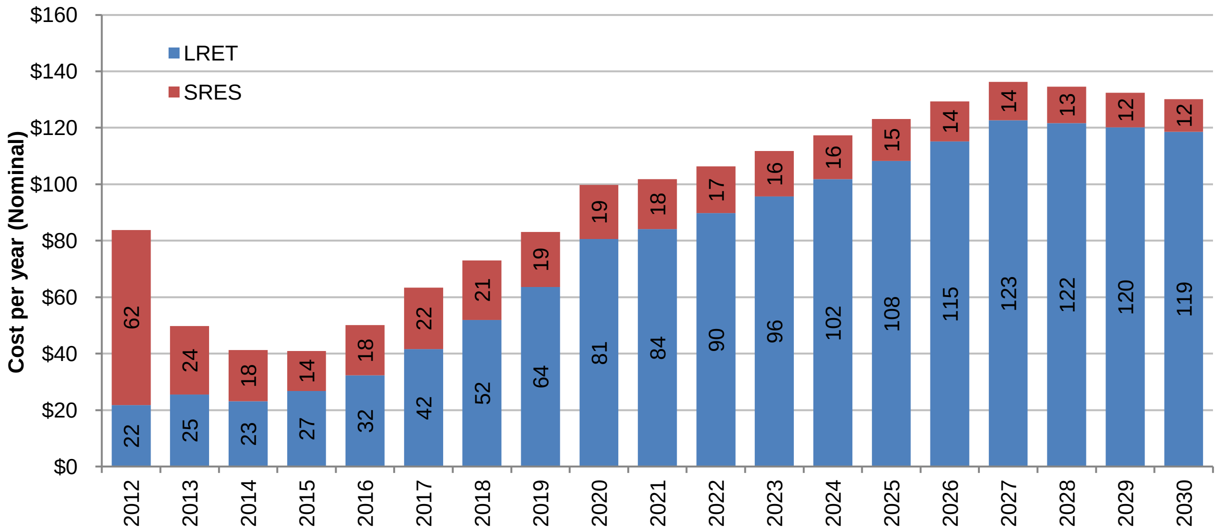
Note: Nominal dollars. PECs = Partial exemption certificates; RPP = Renewable Power Percentage under LRET; STP = Small-scale Technology Percentage under SRES

Data source: ACIL Tasman projections

Figure 8 presents the annual costs from the policies for a typical residential household consuming 7 MWh per annum. Costs in 2012 are estimated to be around $88/year. This is expected to fall over coming years as the STP declines – primarily a result of the declining Solar Credits multiplier for solar PV systems.

LRET is projected to be a much larger cost upon households, with costs projected to increase from around $22/year currently to $123/year by 2027 in nominal terms.

Figure 8 **Indicative annual individual household cost: Base case**



Note: Based on household consumption of7 MWh per year; includes 10% notional energy losses; excludes GST. Nominal dollars based on assumed inflation of 2.5%

Data source: ACIL Tasman estimates

4 'Real 20%' LRET

There have been a number of calls for a revision to the LRET targets which are currently specified in fixed GWh terms. This is in light of the large reductions in anticipated demand relative to what was expected when the original Expanded Renewable Energy Target was announced in 2007.

This scenario seeks to examine the impact of a lower aggregate target for LRET which is based on 20% of the current expected level of energy consumed in 2020.

4.1 Scenario design and key inputs

Table 5 presents the derivation of the 'Real 20%' LRET target level. Herein we have used the projected 'Relevant Acquisition' measure[7] under the legislation as the appropriate measure of Australia energy in 2020. A revised 'Real 20%' target takes this projected amount (49,513 GWh) and subtracts existing baselined energy of 16,584 GWh and the original SRES energy allowance of 4,000 GWh to give a revised 2020 target of 28,929 GWh. We have held the existing target values to 2016 constant in the interests of near-term certainty, and then straight-lined interim targets to the 2020 value and held constant (in GWh terms) thereafter.

These figures are shown graphically and compared with the existing LRET targets in Figure 9.

Table 5 **Revised 'Real 20%' target for the LRET**

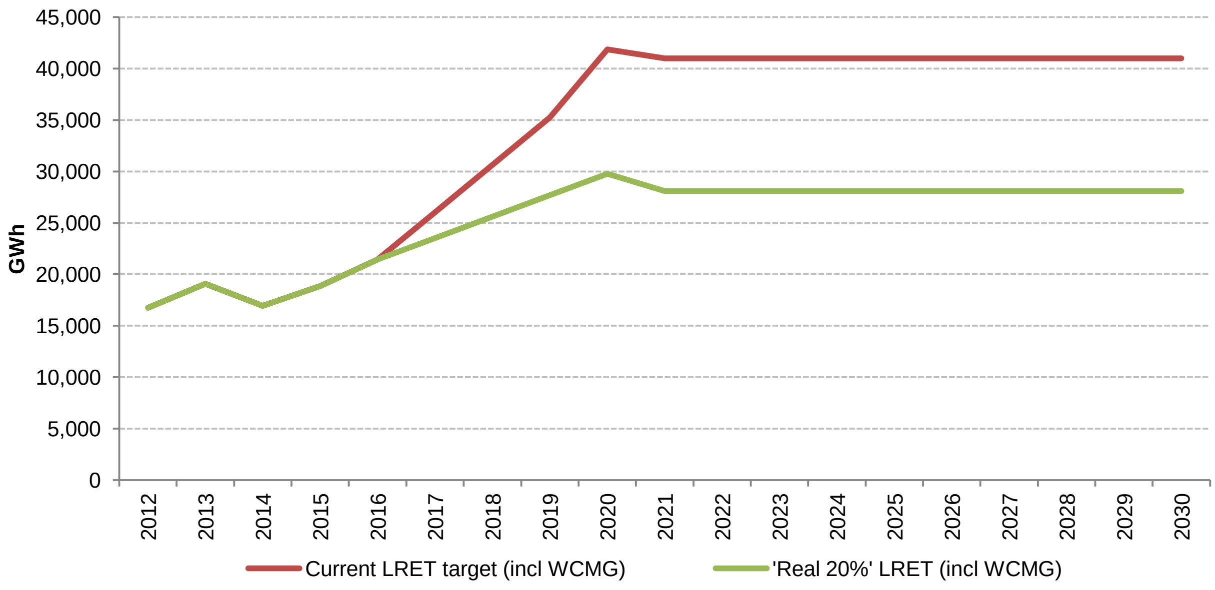
	Relevant acquisitions	2020 20% target	Less existing baselined energy	Allowance for SRES energy (as originally anticipated)	'Real 20%' LRET (excl WCMG)	WCMG	'Real 20%' LRET (incl WCMG)
	GWh	GWh	GWh	GWh	GWh	GWh	GWh
2012	210,989				16,338	425	16,763
2013	216,645				18,238	850	19,088
2014	224,232				16,100	850	16,950
2015	230,189				18,000	850	18,850
2016	234,672				20,581	850	21,431
2017	238,296				22,668	850	23,518
2018	241,108				24,755	850	25,605
2019	244,277				26,842	850	27,692
2020	247,563	49,513	16,584	4,000	28,929	850	29,779

[7] It should be noted that this measure excludes self-generation and off/small grid electricity consumption.

	Relevant acquisitions	2020 20% target	Less existing baselined energy	Allowance for SRES energy (as originally anticipated)	'Real 20%' LRET (excl WCMG)	WCMG	'Real 20%' LRET (incl WCMG)
	GWh	GWh	GWh	GWh	GWh	GWh	GWh
2021	250,064				28,079	0	28,079
2022	252,201				28,079	0	28,079
2023	254,785				28,079	0	28,079
2024	257,867				28,079	0	28,079
2025	261,064				28,079	0	28,079
2026	264,158				28,079	0	28,079
2027	266,978				28,079	0	28,079
2028	269,194				28,079	0	28,079
2029	271,233				28,079	0	28,079
2030	273,421				28,079	0	28,079

Note: WCMG = Waste Coal Mine Gas. Targets for 2012 to 2016 left unchanged in the interests of near-term certainty
Data source: ACIL Tasman analysis

Figure 9 **Revised 'Real 20%' target for the LRET compared with currently legislated target**



Data source: ACIL Tasman analysis

4.2 Wholesale market results

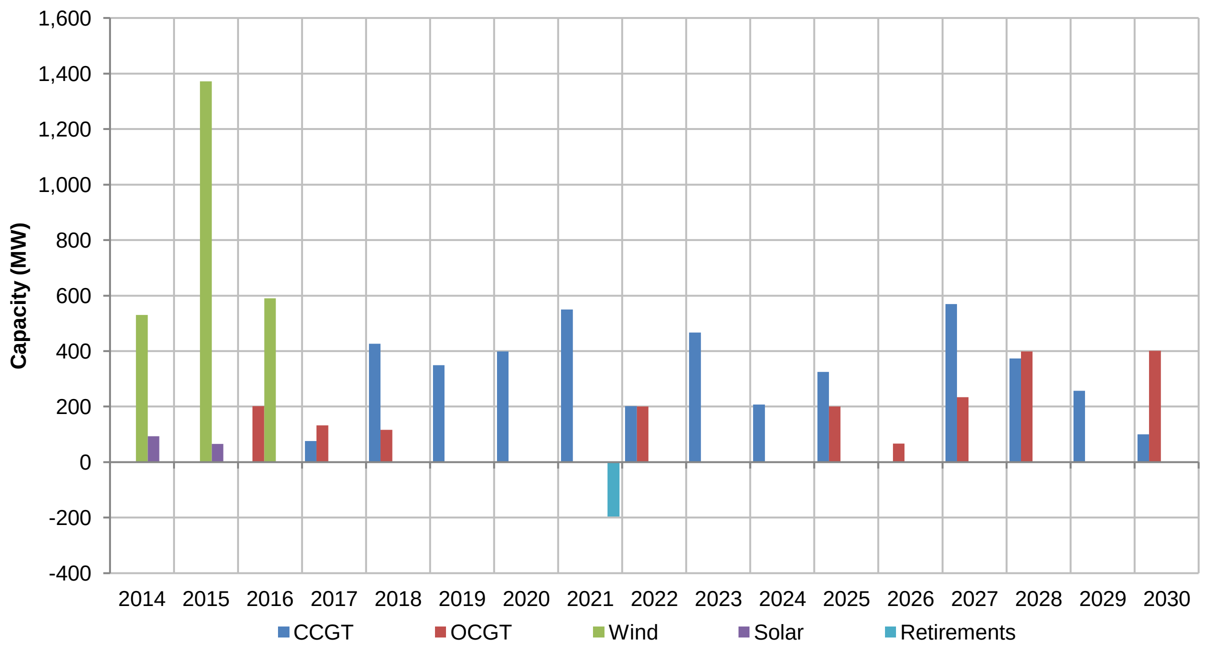
4.2.1 NEM outcomes

Generally NEM wholesale prices are marginally higher in the period to 2020 as a result of the lower level of wind development. While the new entrant schedule has been adjusted accordingly, prices in some regions remain below levels which would make new entrants economic in the period to 2020. In these periods, the reduction in wind development results in higher wholesale price outcomes.

The new entrant profile is somewhat different under this scenario relative to the Base case. Capacity differences in the NEM throughout the period include:

- 3,300 MW less wind
- 600 MW less OCGT capacity
- 1,000 MW more CCGT capacity.

Figure 10 **NEM new entrant and retirement profile: 'Real 20%' scenario**



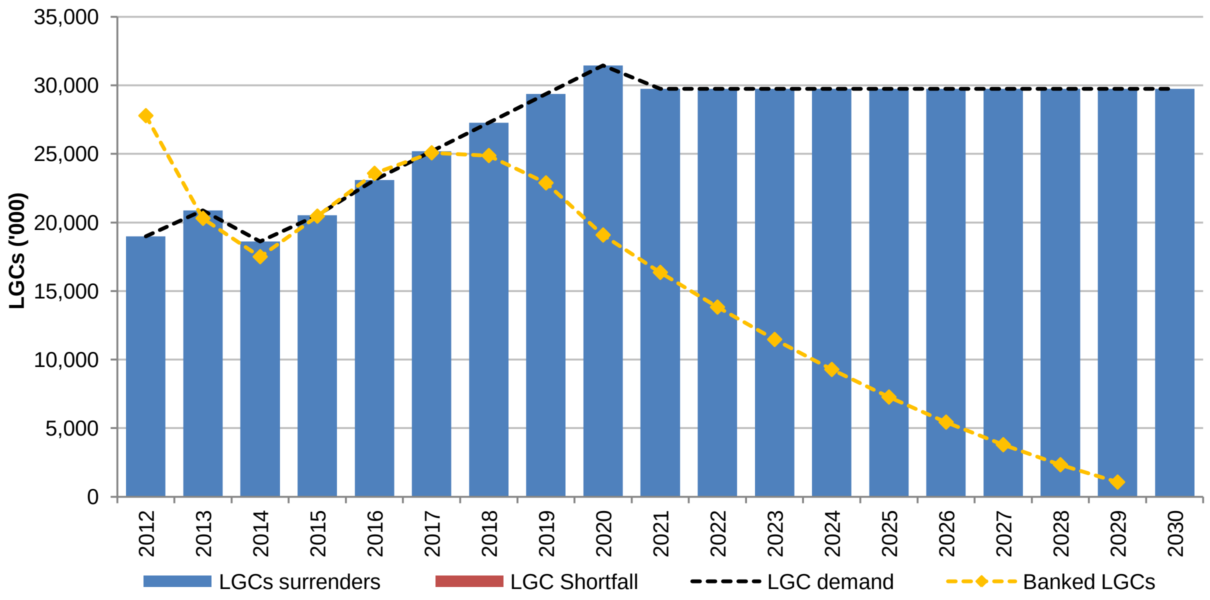
Note: New entrant plant introduced midway through the year will show a proportion of the total capacity in that year, with the balance in the following year.
Data source: ACIL Tasman PowerMark modelling

4.2.2 LRET outcomes

The lower LRET target results in the scheme being fully subscribed throughout as shown in Figure 11. The amount of LGCs banked peaks at around 25 million in 2017 and is gradually drawn down over the period to 2030. This indicates that annual LGC creation from renewable plants is slightly less than the targets from 2019 onwards. Reflecting the perfect foresight assumption employed by the model, the bank is fully drawn down in the final year of the scheme.

Aggregate LGCs created over the period 2012 to 2030 is around 478 million (620 million under the Base case) as detailed in Figure 12.

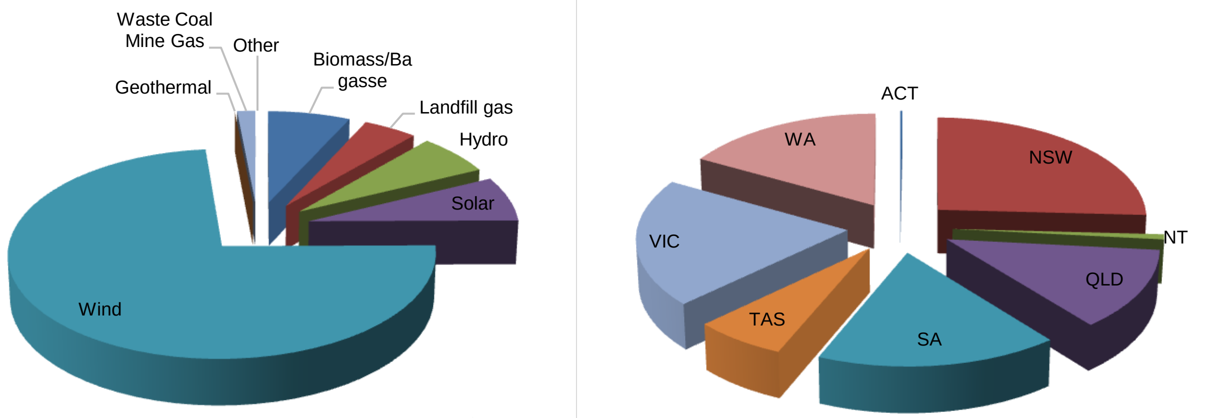
Figure 11 LGC surrenders and banked LGCs 2012-2030: 'Real 20%' scenario



Note: Surrendered include those to acquit obligations and voluntary surrenders. Banked LGCs are presented after that year's surrender has occurred.

Data source: ACIL Tasman RECMark modelling

Figure 12 LGCs created by fuel source and by jurisdiction: 'Real 20%' scenario



Fuel type	LGCs (million)	Share
Biomass/Bagasse	32.9	6.9%
Landfill gas	21.7	4.5%
Hydro	30.6	6.4%
Solar	33.8	7.1%
Wind	351.9	73.6%
Geothermal	0.0	0.0%
Waste Coal Mine Gas	7.3	1.5%
Other	0.0	0.0%
	478.1	100.0%

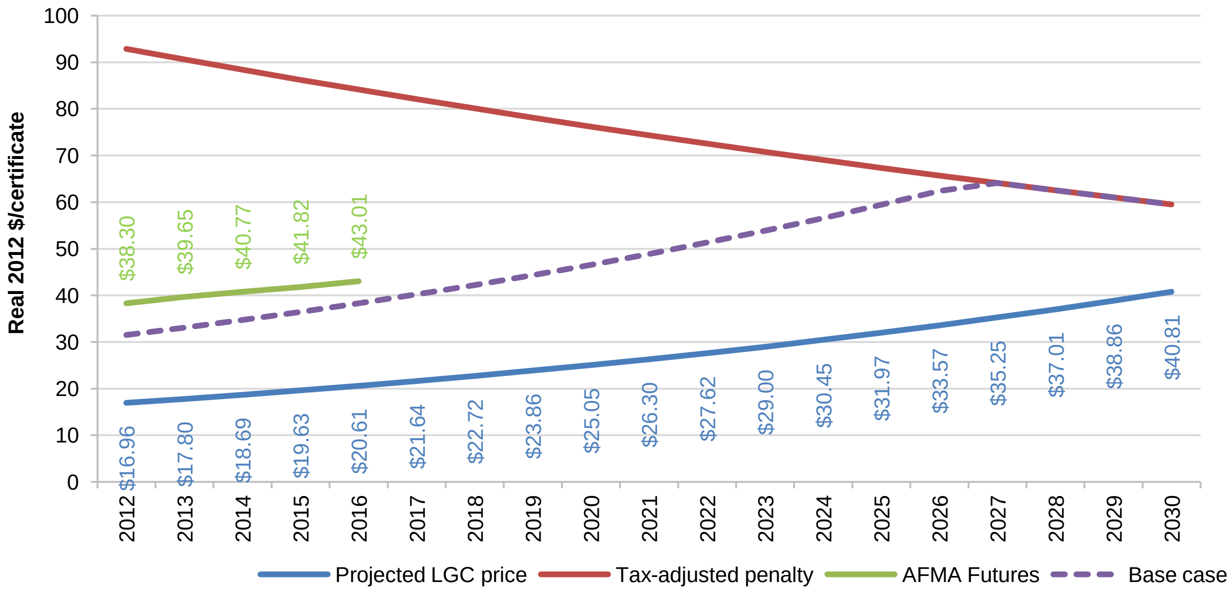
Jurisdiction	LGCs (million)	Share
ACT	0.9	0.2%
NSW	122.6	25.6%
NT	3.9	0.8%
QLD	60.3	12.6%
SA	81.7	17.1%
TAS	31.5	6.6%
VIC	96.6	20.2%
WA	80.6	16.9%
Total	478.1	100.0%

Note: Aggregate projected LGCs created 2012 to 2030. Includes LGCs created from existing accredited generators.

Data source: ACIL Tasman RECMark modelling

Reflecting the lower target, LGC prices are much lower at around $17/certificate in 2012, escalating at the assumed holding cost (5% real). This is around $20 below the current futures price for 2012 LGCs. If this change to the target was announced, spot prices would immediately adjust downwards based on the revised outlook.

Figure 13 **Projected LGC prices and current futures prices: 'Real 20%' scenario**



Note: AFMA futures prices are mean of all mids as at 9 August 2012, converted to Real 2012 dollars. Inflation of 2.5% used throughout. Timing of AFMA prices have not been adjusted to match RECMark timing (i.e. AFMA Cal12 is for delivery in Jan 2013; whereas RECMark 2012 price applies throughout calendar year 2012).
Data source: ACIL Tasman RECMark modelling, AFMA

4.2.3 SRES outcomes

Up-take under SRES are identical to those within the Base case however there are some feedback loops associated with the amount of partial exemption certificates such that the STP will differ slightly. As the number of PECs issued is dependent upon the aggregate cost of the RET compared with the original MRET, fewer PECs will be issued under this scenario. This therefore reduces the cost of SRES to non-exempt liable loads although the difference compared with the Base case is largely immaterial.

4.3 Aggregate RET costs

The adjustment to the LRET target to account for the lower anticipated 2020 demand level results in the overall subsidy falling to around $28 billion over the period in nominal terms (a $25.2 billion reduction from the Base case) as detailed in Table 6. The RPP peaks at around five percentage points lower in 2020 (13.3% compared with 18.8% in the Base case).

Table 6 **RET cost summary: 'Real 20%' scenario**

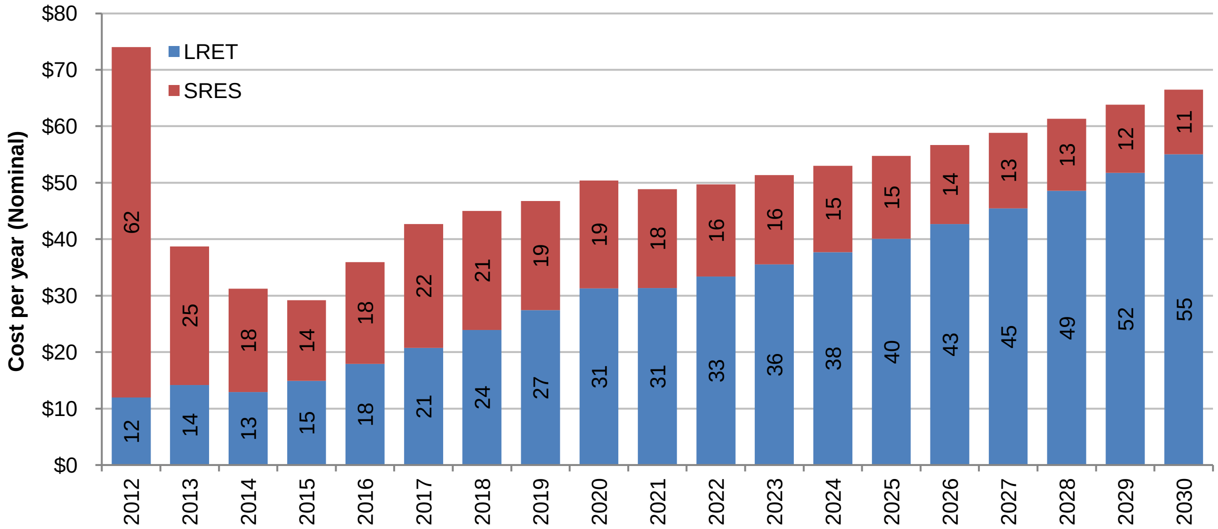
Calendar year	Relevant acquisitions	PECs	Reduced acquisitions	Projected RPP	Projected STP	LRET cost	SRES cost	Total RET cost
	GWh	GWh	GWh	%	%	$m	$m	$m
2012	210,989	28,860	182,129	9.15%	23.96%	283	1,469	1,751
2013	216,645	27,581	189,065	10.10%	7.97%	348	603	951
2014	224,232	25,582	198,649	8.53%	5.95%	333	472	805
2015	230,189	24,462	205,727	9.16%	4.63%	398	381	780
2016	234,672	25,065	209,608	10.22%	5.85%	488	490	978
2017	238,296	24,815	213,482	11.02%	7.11%	576	607	1,183
2018	241,108	23,666	217,442	11.78%	6.85%	675	596	1,270
2019	244,277	23,688	220,589	12.55%	6.27%	785	554	1,339
2020	247,563	23,960	223,603	13.32%	6.19%	909	554	1,463
2021	250,064	23,519	226,546	12.39%	5.69%	922	516	1,438
2022	252,201	23,270	228,932	12.27%	5.31%	993	486	1,479
2023	254,785	23,174	231,611	12.12%	5.15%	1,068	477	1,545
2024	257,867	23,125	234,743	11.96%	4.96%	1,150	466	1,616
2025	261,064	23,252	237,811	11.81%	4.76%	1,238	453	1,690
2026	264,158	23,736	240,421	11.68%	4.55%	1,332	438	1,770
2027	266,978	24,192	242,786	11.57%	4.34%	1,433	422	1,855
2028	269,194	24,589	244,605	11.48%	4.14%	1,543	405	1,948
2029	271,233	24,067	247,166	11.36%	3.92%	1,660	388	2,048
2030	273,421	23,520	249,901	11.24%	3.70%	1,787	370	2,157
Total						17,921	10,145	28,066

Note: Nominal dollars. PECs = Partial exemption certificates; RPP = Renewable Power Percentage under LRET; STP = Small-scale Technology Percentage under SRES

Data source: ACIL Tasman projections

The lower RPP combined with the lower projected LGC prices combine to lower the effective cost of the scheme upon households as shown in Figure 14. Total cost of the RET policy in 2020 to an average household is around $50/year, compared with around $100/year under the Base case.

Figure 14 **Indicative annual individual household cost: 'Real 20%' scenario**



Note: Based on household consumption of7 MWh per year; includes 10% notional energy losses; excludes GST. Nominal dollars based on assumed inflation of 2.5%

Data source: ACIL Tasman estimates

5 Comparisons of scenarios

The RET in its current form is a significant subsidy with an estimated total direct value of $53.3 billion within the Base case as shown in Table 7. Over 80% of this is associated with the LRET, where costs are anticipated to grow over time, in line with increasing fixed GWh targets. The direct costs of subsidising small-scale systems, whilst currently high due to the influence of Solar Credits multiplier, is projected to decrease over time.

The 'Real 20%' scenario which lowers the fixed 2020 GWh targets in accordance with the current demand outlook reduces the aggregate direct cost to $28.1 billion ($25.2 billion lower than the Base case). This adjustment results in the 2020 target falling to around 28,000 GWh compared with the current 41,000 GWh level. The lower target results in lower certificate prices, and a lower level of large-scale renewable deployment (wind in the NEM is around 3,300 MW lower by 2020 under this scenario).

Table 7 **Projected aggregate subsidies paid through RET**

Scenario	Aggregate LRET subsidy 2012-2030	Aggregate SRES subsidy 2012-2030	Aggregate RET subsidy 2012-2030
	$ billion	$ billion	$ billion
Base case	43.2	10.1	53.3
'Real 20%' LRET	17.9	10.1	28.1

Note: Nominal dollars.

Data source: ACIL Tasman projections

Modifications to the RET will have some short-term impacts upon wholesale electricity price outcomes. Policy changes which increase renewable development (at the margin) in the NEM will tend to depress wholesale electricity prices. Conversely, policy changes which reduce the amount of renewable development will tend to increase wholesale electricity prices. However, these effects will be small and the amount and timing of new entrant fossil fuelled capacity will adjust accordingly such that the wholesale market will not deviate from its equilibrium price path.[8] Owing to the lumpy nature of generation investment, in most cases the influence of RET policy changes upon modelled wholesale market outcomes, once new entry levels have been reached, can be characterised as modelling noise.

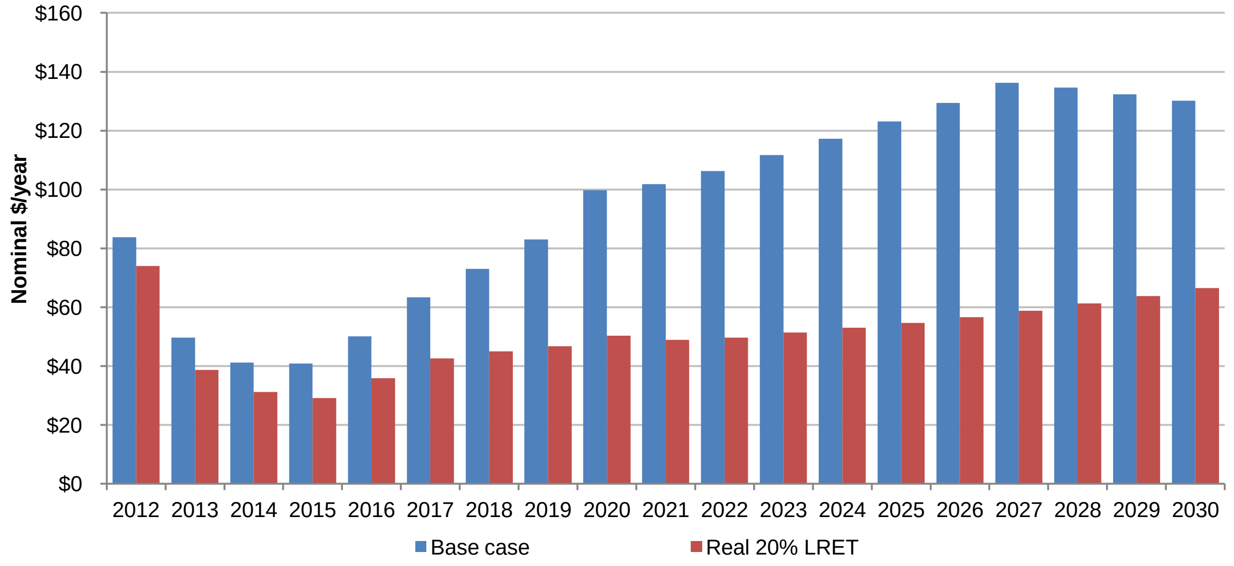
[8] Provided the RET policy settings doesn't result in a permanent change to the marginal new entrant technology.

Figure 15 compares the estimated individual household direct cost of the LRET/SRES under the various scenarios examined. The total cost under the Base case is estimated to be around $80/year in 2012 and projected to fall to around half this value by 2014. This then rises to peak at just under $140/year by 2027. Note that this does not include the shortfall payments which would be made in the period 2027 to 2030.

The 'Real 20%' LRET results in a dramatic reduction in direct costs to residential electricity consumers with immediate effects through lower certificate prices and lower RPP values from 2016 onwards. The aggregate cost in 2020 for a household under this scenario is around half that projected within the Base case.

In summary, the total direct cost upon households from the RET scheme under each scenario over the period 2012 to 2030 (in nominal terms) is $1,800 under the Base case and only $960 under the 'Real 20%' scenario.

Figure 15 **Indicative annual individual household cost of RET: Scenario comparison**



Note: Based on household consumption of7 MWh per year; includes 10% notional energy losses; excludes GST. Nominal dollars based on assumed inflation of 2.5%. Includes both LRET and SRES costs

Data source: ACIL Tasman estimates

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