Analysis of the impact of the Small Scale Renewable Energy Scheme

Projection of retail electricity price impacts and abatement to 2020

Prepared for the Australian Energy Market Commission

November 2011

ACIL Tasman

Economics Policy Strategy

Reliance and Disclaimer

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Executive summary

ACIL Tasman has been engaged by the Australian Energy Market Commission (AEMC) to undertake analysis of the Small-scale Renewable Energy Scheme (SRES) over the period to 2020.

The project requires projections of the likely level of uptake of small generating units (SGUs) – primarily solar photovoltaic (PV) systems – and solar water heaters (SWHs), and the resulting creation of Small-scale Technology Certificates (STCs) under the SRES for each Australian State and Territory. It also requires estimates of the cost impact of the SRES in cents per kilowatt-hour for each State and Territory that would feed through to retail electricity prices, and the likely effect on greenhouse gas emissions levels.

ACIL Tasman's core analysis was undertaken in April, May and June 2011 using data on STC creation provided by the Office of the Renewable Energy Regulator (ORER) that was current in March 2011. However, ACIL Tasman updated the analysis during November 2011 to take into account various changes to feed-in tariff policies that occurred during the second half of 2011. The updated analysis presented here did not benefit from access to updated data on STC creation, take into account changes to PV system costs, or update retail electricity price projections to reflect the Commonwealth Government's carbon pricing policy announced in July 2011.

Due to the relative stability of STC creation by SWHs, ACIL Tasman did not update its SWH projection in November 2011, focusing entirely on changes to STC creation rates by solar PV systems.

Approach

Different approaches were used to project the uptake of solar PV systems and SWHs.

The projection of uptake – and therefore STCs created from solar PV systems – involved the analysis of historical and projected financial paybacks associated with the installation of such systems. ACIL Tasman's analysis of the financial payback for solar PV technologies focused on three key drivers:

- Up-front subsidies and ongoing assistance (e.g. feed-in tariffs) available for solar PV systems through various government policies
- Retail electricity prices faced by households and small businesses (as primary installers of solar PV). This was built up using projections of the cost components including wholesale prices, retail costs, network costs and Large-scale Renewable Energy Target (LRET)/SRES charges.
- Solar PV system costs and projected changes over time.

The historical financial paybacks were used to construct an econometric model of the relationship between financial payback and capacity installed in each jurisdiction. This model was then used to project future PV capacity installed in each jurisdiction, based on estimated future paybacks available. Capacity installed allowed the calculation of the implied STC creation rate for solar PV systems.

The payback for solar PV systems and number of STCs created were calculated under a range of scenarios as follows:

- **'Core Scenario'**: this scenario was based on SRES and FiT policy settings as in place at the start of November 2011.
- **'Elevated Uptake Scenario'**: this scenario was based on the adjustment of various policy settings to support overall higher levels of STC creation by solar PV systems and includes a carbon price.
- **'Reduced Uptake Scenario'**: this scenario was based on the adjustment of various policy settings to lead to lower levels of STC creation by solar PV systems.
- **'Carbon Scenario'**: this scenario adopts all assumptions as per the Core Scenario, except that the Commonwealth Government is assumed to introduce a carbon price from 1 July 2012 that increases electricity prices, and therefore improves the financial return to solar PV systems. The carbon price used for this scenario was based on 2009 Treasury modelling for the Carbon Pollution Reduction Scheme (CPRS) for a 5% reduction target on year 2000 level emissions by 2020, rather than the carbon price series announced as part of, and modelled for, the Commonwealth Government's *Clean Energy Future* policy.
- **'WA network sensitivity'**: this scenario adopts all assumptions as per the Core Scenario but adopts the WA Government's estimate of the long-term trend in electricity network costs in that state to 2020.
- **'Counterfactual Scenario'**: this scenario removes the effects of the SRES (i.e. the STC price is zero).

Projections for solar water heaters were developed through a stock replacement model rather than a payback analysis. SWH uptake is heavily affected by policy, regulatory and stock replacement drivers on top of direct economic (e.g. cost) drivers. Accordingly, we considered that a replacement stock model that captured 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, offered greater explanatory power than a pure payback model.

Projections of SWH uptake were developed under four separate scenarios: Reference, High, Low and Counterfactual. For the purposes of the overall STC creation estimate, ACIL Tasman has combined the Reference SWH projection with the relevant Solar PV scenario. However, the High and Low SWH projections highlight the potential uncertainty in relation to certificates created from solar water heaters.

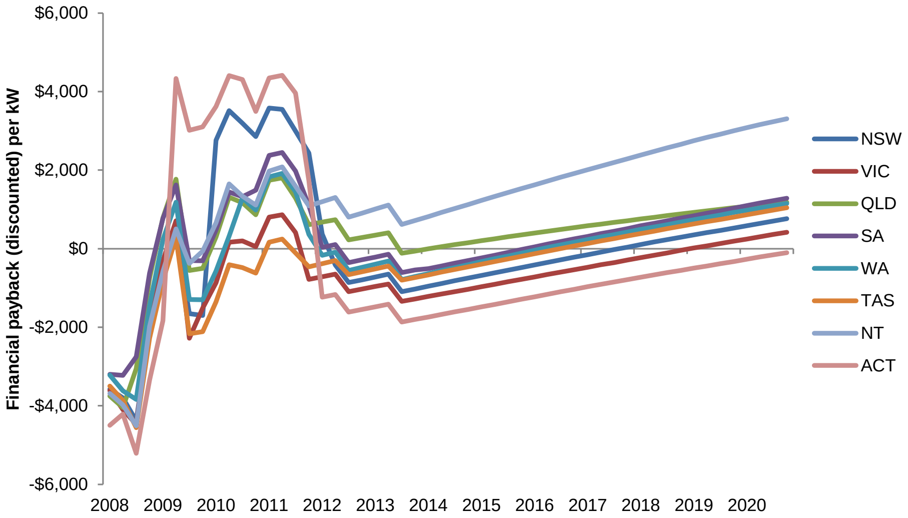
Solar PV results

Figure ES 1 shows the historical and projected financial paybacks for each jurisdiction from installation of a solar PV system under the Core Scenario. The financial payback value represents the net present value of costs and benefits derived from the system using a nominal discount rate of 10% on a per kilowatt basis. This calculation includes the impact of the upfront subsidy provided through SRES, any ongoing assistance through feed-in tariffs (either gross or net) and avoided electricity costs.

The analysis indicates that financial paybacks are positive for all jurisdictions for systems installed in early 2011, but are projected to fall rapidly reaching a low point for installations in mid 2013 when the Solar Credits multiplier falls to 1 and most Feed-in Tariff (FiT) schemes have reached their stated cap. Similar payback profiles were projected for the other scenarios examined. Differences between scenarios were primarily a result of different Solar Credit multiplier settings and jurisdictional FiT settings. The Counterfactual Scenario, which did not include the upfront SRES subsidy, saw significantly lower financial paybacks.

Figure ES 2 shows the aggregate solar PV capacity projected to be installed each year across all scenarios. The uptake of solar PV systems across the scenarios follows a similar pattern to the financial payback, with a large fall in installation rates projected to 2013-14, then increasing levels of installations due to rising retail electricity prices and falling PV system costs. The pattern aligns with the projected paybacks available.

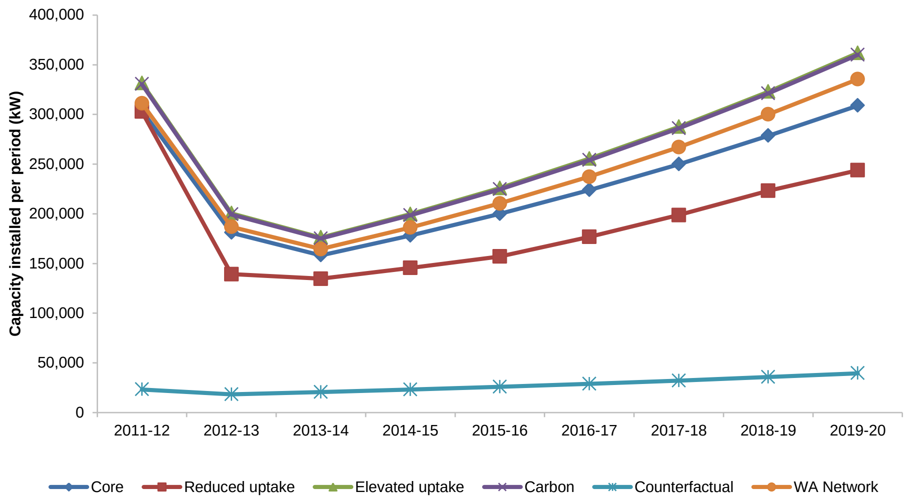
Figure ES 1 **Projected financial payback results: Core Scenario**



Note: Financial payback using a nominal discount rate of 10%

Data source: ACIL Tasman analysis

Figure ES 2 **Aggregate PV capacity installed per period: All scenarios**



Data source: ACIL Tasman analysis

Solar water heaters

SWHs are a relatively mature technology and have been part of the technology suite for water heating for decades in Australia. SWHs receive subsidies via upfront rebates (at State or Federal level) and are eligible to create Renewable Energy Certificates (RECs) or STCs.

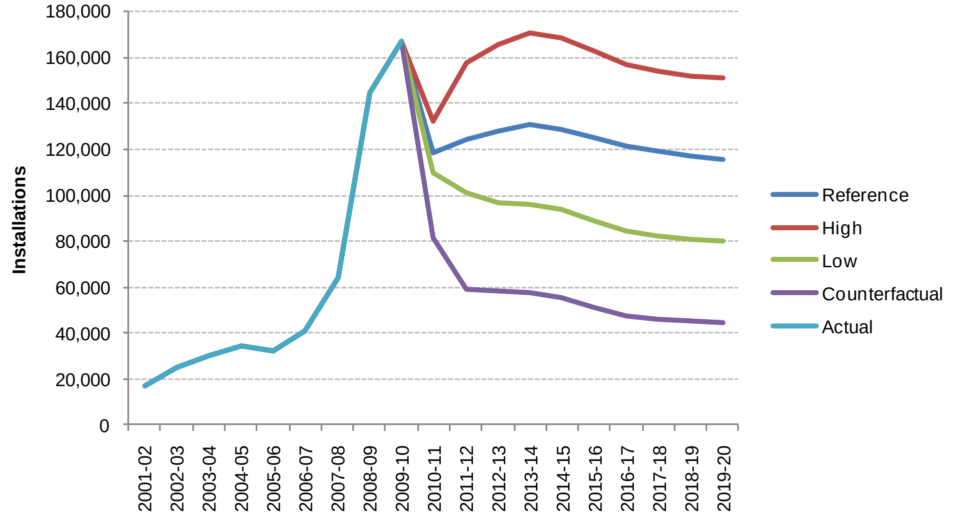
Recent years have seen a significant increase in installation rates – particularly in 2009 – where installations were occurring on an opportunistic basis rather than simply as stock replacement. Part of the driver for this surge was the large uptake of commercial scale units which were being installed on a purely commercial basis rather than replacing existing hot water systems that had reached the end of their useful life. However, changes in regulations introduced in June 2010 have reduced the likelihood of installations of this nature occurring in the future.

ACIL Tasman's projection of STC creation by SWHs was developed through use of a water heater stock model, which was used to analyse:

- The changing size and technology composition of the (residential) water heater stock from 1980 to 2020
- Historic rates of substitution between water heater technologies on a 'technology pair' basis, e.g. solar for electric, gas for electric, solar for gas etc.
- Historic technology shares in the new building water heater market
- The overall effect of these trends on SWH installation and STC creation rates over the period 2011 to 2020.

Figure ES 3 shows the projected SWH installations across Australia under the various SWH scenarios. Under the Reference case, installations are projected to level out at around 120,000 per annum, with reasonably wide High/Low bounds of 160,000 and 80,000 installs respectively.

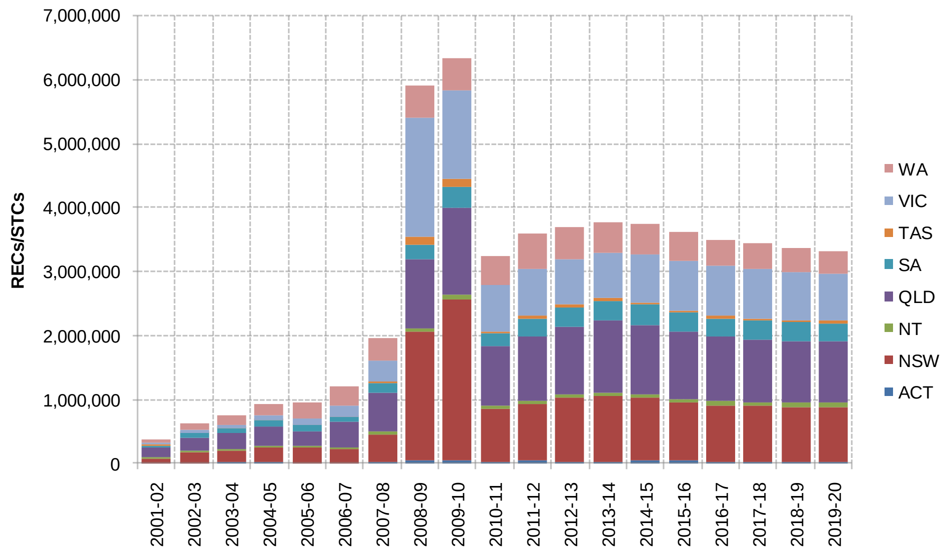
Figure ES 3 **Projected SWH installations**



Note: Actual installations to 31 December 2010. Installations eligible for RECs/STCs only.
Data source: ACIL Tasman analysis

Figure ES 4 shows the historic REC creation and projected STCs created from SWH installs to 2019-20 under each scenario. The number of certificates created by a SWH installation is not affected by the Solar Credits multiplier but are affected by the capacity of the system installed. The high level of REC creation during 2008-09 and 2009-10 reflects not only a high level of installations, as presented in Figure ES 3, but also a very high level of RECs created per installation. This was a result of the eligibility of air-source heat-pump water heaters of greater than 425 litres capacity to create RECs at that time. The eligibility of these systems to create RECs was phased out from June 2010.

Figure ES 4 **Historic and projected REC/STC creation from SWH by jurisdiction: Reference case**



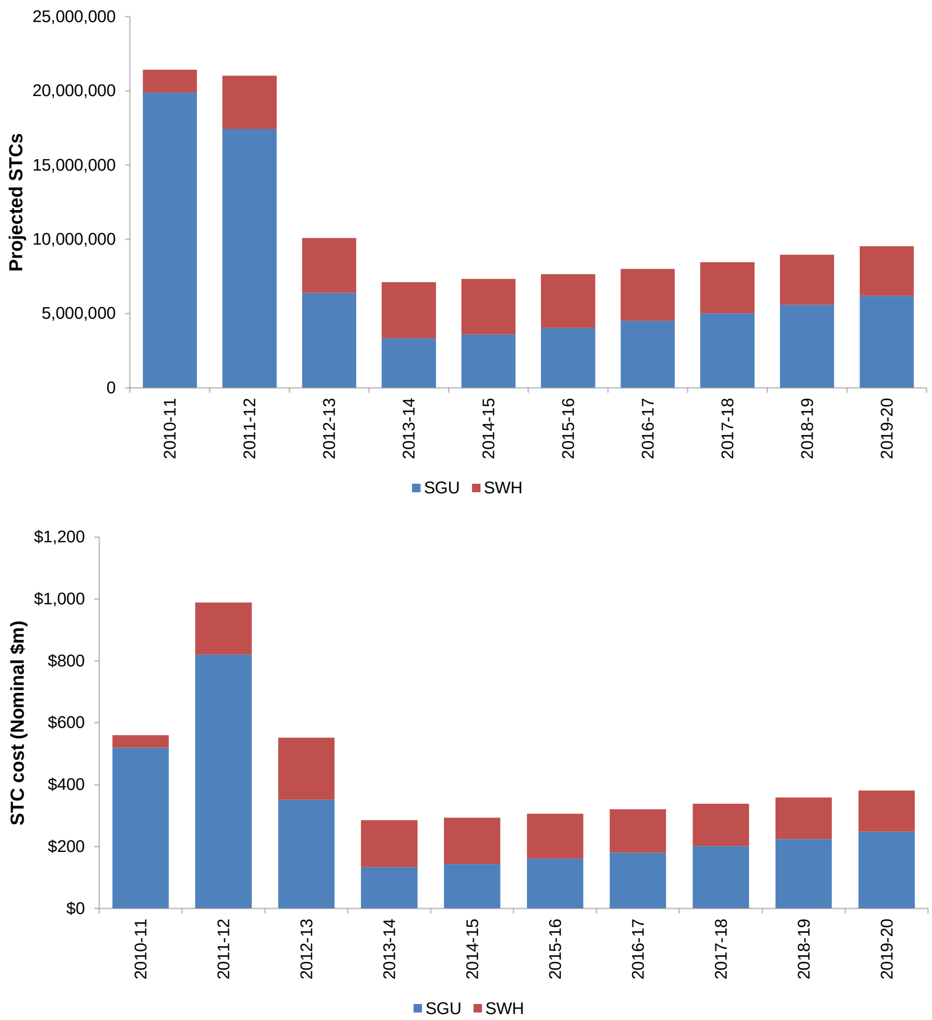
Note: Actual REC creation to 31 December 2010.
Data source: ACIL Tasman analysis

SRES costs

Figure ES 5 shows the projected number of STCs created and costs for the Core Scenario. The total STCs created over this period is around 109.6 million. 76 million (69%) of these are attributable to solar PV installations and the remainder of 33.6 million (31%) attributable to SWH.

STC costs are fixed for calendar year 2011 as the Office of the Renewable Energy Regulator (ORER) has set the binding Small Technology Percentage (STP) at 14.8%, which is equivalent to 28 million STCs. Based on the notional cost of $40/certificate, this implies a calendar year cost of $1.12 billion. Any additional STCs created during calendar year 2011 have been carried forward in our analysis as an increase to the 2012 liability. The total cost of certificates over the period to 30 June 2020 amounts to $4.4 billion in nominal terms. SRES will continue to incur costs to end users through to the end of scheme in 2030.

Figure ES 5 **Projected STCs created and costs: Core Scenario**



Note: The 2010-11 value relates to the period from 1 January 2011. The STC target for 2011 is fixed at 28 million. Excess STCs during 2011 count toward the calendar year 2012 requirement.

Data source: ACIL Tasman analysis

Table ES 1 details the projected SRES costs (expressed in cents/kWh) for end user consumers under each scenario. These values have been calculated by taking the annual SRES costs (presented above) and dividing by total end use consumption, less partial exemptions relating to emissions-intensive, trade-exposed (EITE) activities. The impact on retail electricity prices peaks in 2011-12 and falls significantly under all scenarios by 2013-14. This reduction in retail costs is primarily driven by the scheduled reduction in the Solar Credits multiplier, which falls to 1 over this period (from 5 in early 2011). Obligations to surrender STCs are achieved through the STP liability and therefore costs are applied equally to all non-exempt electricity users throughout Australia.

Table ES 1 **Projected impact of SRES on retail electricity prices (nominal cents/kWh)**

Scenario	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Core	0.30	0.53	0.29	0.14	0.14	0.15	0.15	0.16	0.17	0.17
Elevated	0.30	0.58	0.32	0.15	0.15	0.16	0.17	0.18	0.19	0.20
Reduced	0.30	0.53	0.22	0.13	0.11	0.10	0.10	0.10	0.11	0.10
Carbon	0.30	0.58	0.32	0.15	0.15	0.15	0.16	0.17	0.18	0.19
WA network	0.30	0.54	0.29	0.14	0.15	0.15	0.16	0.17	0.17	0.18
Counterfactual	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Data source: ACIL Tasman analysis

It should be noted that the projections of PV uptake are quite conservative, particularly for the period April to June 2011. Observed installation rates in the lead up to the reduction in the Solar Credits multiplier on 1 July 2011 suggest a significant surge in installations seeking to receive the multiplier of five.

Further, ongoing strong installation rates have been observed during the second half of 2011, reflecting that the rate of reduction in PV system costs in recent months is greater than that assumed in our April 2011 system cost projection.

The events of the period April to June 2011 indicate that an alternative functional form for the econometric model used in this analysis could potentially offer greater explanatory power in dealing with sudden policy changes of the kind observed during 2011. It is likely that consumers respond not only to the financial return available from committing to a PV installation in the present, but also to anticipated reductions (or increases) to this return in the immediate future. For any given level of absolute financial return, installation rates are likely to be higher if financial returns are anticipated to reduce in future, for example due to the closure of a feed-in tariff or reduction in the Solar Credits multiplier. Conversely, if financial returns are expected to stay broadly constant or improve, a lower level of present day installation could be expected as consumers are more 'patient' in committing to installations.

Notwithstanding this, the materiality of the changes to PV policy settings are unprecedented in the data set available for this exercise, and so it is likely that calibrating an econometric model to accurately predict the extreme surge in installation rates during April to June 2011 would be challenging.

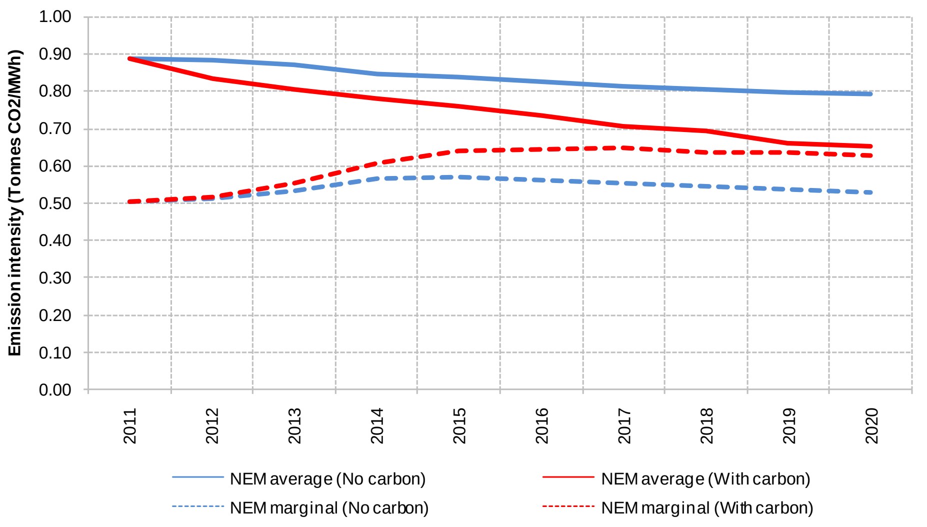
Nevertheless, as feed-in tariffs phase out and the financial return to PV systems becomes more strongly driven by reducing system costs and higher electricity prices, rather than STC and feed-in tariff subsidies, the scope for substantial reductions in financial returns over the longer projection period is more limited. Accordingly, the state and national level projections to 2020 remain useful in outlining the aggregate cost and emissions trends arising from the SRES policy, particularly in the context of reducing PV system costs and rising electricity prices.

Abatement

In terms of abatement of greenhouse gas emissions, the analysis considered the impact of SWH and solar PV systems separately. The average emissions intensity of electricity supply was used for SWH due to the largely 'off-peak' nature of electricity used to heat water, which will tend to more strongly reflect the average emissions intensity of the grid in a given location.

However the output profile for solar PV systems is somewhat different in that they only produce power during daylight hours. The abatement achieved from solar PV systems was therefore analysed in more detail through electricity market modelling which examined the marginal emissions intensity of displaced energy from PV output as shown in Figure ES 6. It was found that the energy displaced from PV systems has a much lower emissions intensity than the average intensity from the grid. PV systems largely displace output from gas-fired technologies (combined-cycle gas turbines and open-cycle gas turbines), rather than coal. It was also found that the marginal emissions intensity was somewhat higher under a carbon scenario. This was a result of coal becoming more marginal during daylight hours.

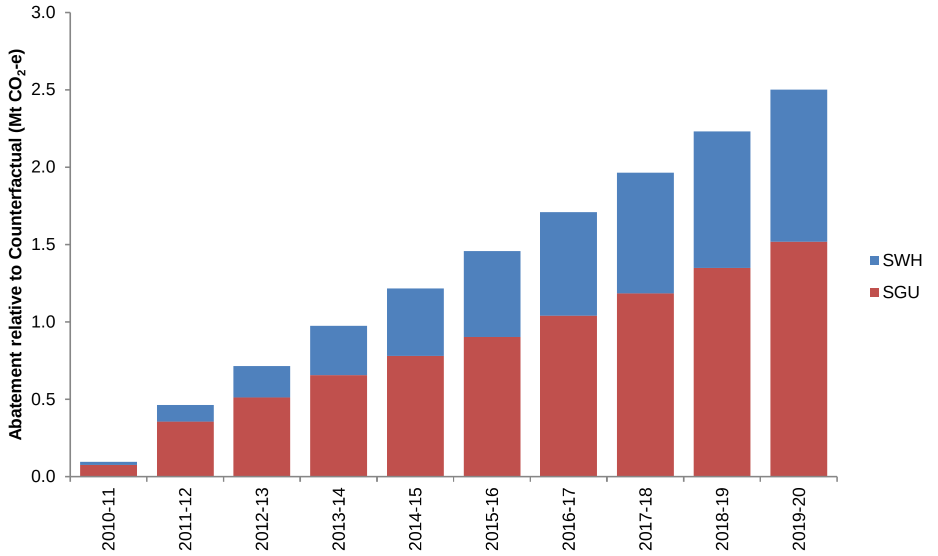
Figure ES 6 **Average grid and marginal emissions intensity for the NEM**



Data source: ACIL Tasman PowerMark modelling

Figure ES 7 shows the projected aggregate abatement relative to the Counterfactual Scenario broken down into SWH and solar PV (or SGU) components. Abatement rises to around 2.5 Mt CO_2-e per year by the end of the projection period under the Core Scenario.

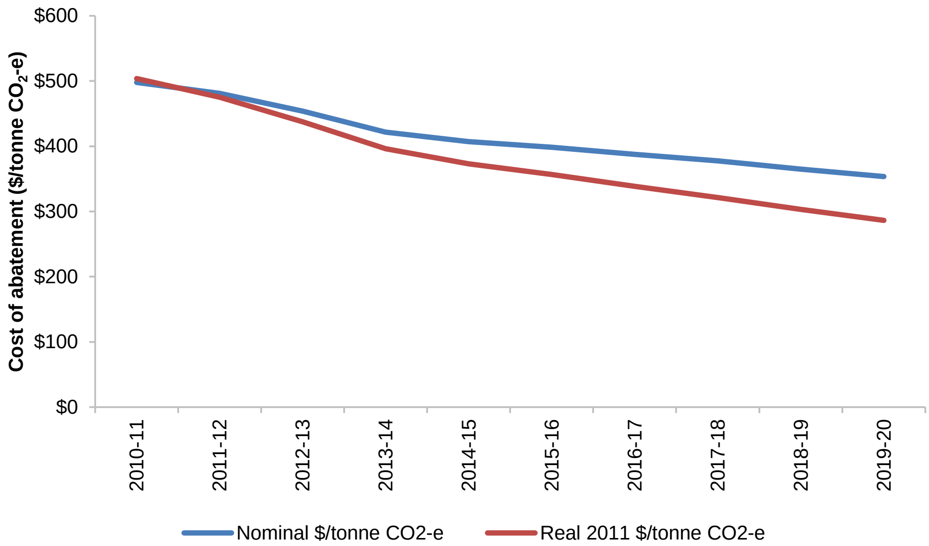
Figure ES 7 **Total abatement relative to counterfactual: Core Scenario**



Note: Uses Reference case SWH projections
Data source: ACIL Tasman analysis

Costs of abatement from solar PV were calculated as the annualised economic resource cost divided by the gross abatement achieved. This involved converting total system costs to an annualised equivalent and subtracting the avoidable economic cost of electricity produced. This total cost each year is then divided by the gross emissions avoided resulting from the installations. The resulting economic cost of abatement is shown in Figure ES 8 .

Figure ES 8 **Economic cost of abatement from solar PV: Core Scenario**



Note: This chart presents the annualised abatement costs of the stock of PV systems in operation during the relevant financial year. Accordingly, the cost in any given year reflects the weighted economic cost of systems installed in all preceding years. A full description of the methodology employed is provided in section 6.4.

Data source: ACIL Tasman analysis

This indicates the PV technology offers an expensive means of achieving abatement, at costs of around $300-$500/tonne CO_2-e in real 2011 dollars. However, this analysis does not illustrate the cost of abatement delivered by the SRES policy itself, or other policies that support solar PV systems. This is primarily because it is difficult to disaggregate the abatement (and therefore cost) that should be attributed to the SRES as distinct from other policies that support solar PV installations.

In addition, the SRES and feed-in tariffs build on an implicit (and largely unintended) subsidy afforded PV systems through the current structure of retail electricity bills in which around 90% of charges are provided as variable components. Any avoided electricity purchases as a result of own PV consumption effectively accrues benefits far in excess of the true economically variable costs.

Whilst the precise effect of individual policy measures is hard to disaggregate, subsidies such as SRES and jurisdictional FiT schemes have a high economic cost and correspondingly deliver greenhouse gas abatement at high cost.

1 Introduction and background

ACIL Tasman has been engaged by the Australian Energy Market Commission (AEMC) to undertake analysis of the Small-scale Renewable Energy Scheme (SRES) over the period to 2020.

The project requires projections of the likely level of uptake of solar photovoltaic (PV) systems solar water heaters (SWHs) and creation of Small-scale Technology Certificates (STCs) under the SRES for each Australian State and Territory, together with the likely effect on greenhouse gas emissions levels. It also requires estimates of the cost impact of the SRES in cents per kilowatt-hour for each State and Territory that would feed through to retail electricity prices.

This report sets out ACIL Tasman's findings under this project.

- Chapter 2 describes the methodology employed in projecting uptake and costs under SRES.
- Chapter 3 details the financial payback methodology employed for solar PV systems and details the assumptions used to assess financial returns from installation of solar PV systems for households.
- Chapter 4 examines the econometric analysis which uses multiple regression techniques to establish a relationship between financial payback and installations of solar PV systems. This model is then used to project uptake of solar PV systems in each jurisdiction.
- Chapter 5 details the solar water heater stock model that was developed to project uptake in each jurisdiction.
- Finally, Chapter 6 presents the results from the SRES projection model which includes the relevant outputs such as the number of STCs created, the cost of certificates, impacts upon retail electricity prices and greenhouse gas emissions abatement.

2 Approach

As required by the AEMC, this analysis has examined STC creation rates for all STC-eligible technologies (small generation units, or SGUs, encompassing solar PV systems, micro-hydro and micro-wind; and solar water heaters, or SWHs). However the analysis focuses on the technologies primarily driving changes in STC creation rates, namely solar PV systems and SWHs.[1]

The methodology for this project involved the development of a forecast model which derives its inputs from a range of different sources including multivariate econometric regressions and sub models as shown in Figure 1.

For solar PV systems, the approach consists of payback analysis which fed into a more general econometric approach.

Projections for SWHs were developed through a stock replacement model rather than a formal payback analysis. SWH uptake is heavily affected by policy, regulatory and stock replacement drivers on top of direct economic (i.e. cost) drivers. Accordingly, we considered that a stock model that captured 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, offered greater explanatory power than a pure payback model.

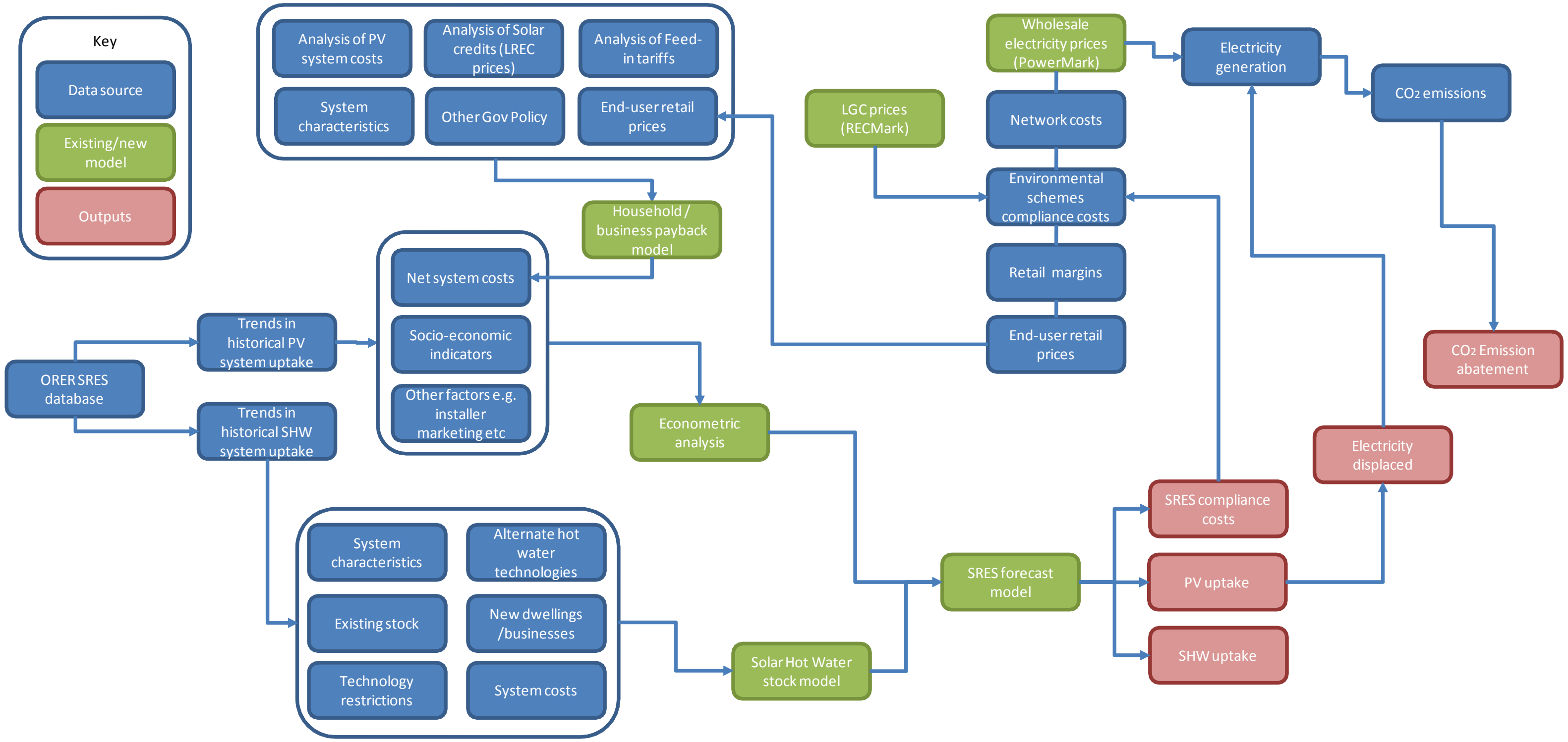
These components provided the inputs into an integrated purpose built SRES forecast model which provided the necessary outputs. The forecast model allowed key drivers to be altered and outcomes analysed through sensitivity analysis.

This uptake analysis then forms the basis for estimates of the cost of, and abatement from, the SRES.

We note that there is a degree of circularity in relation to payback periods for STC-eligible technologies and take-up of these technologies. The greater the uptake of eligible technologies under SRES, the larger the impact on retail electricity prices (as costs are spread across all electricity consumers). This in turn makes additional installations more compelling. This circularity is noted in Figure 1 below. However, as SRES costs are only a relatively small component of end user electricity prices, this feedback is relatively minor and we found that results quickly stabilised through iterating the payback period analysis and SRES uptake forecast model.

[1] Solar PV accounts for around 99.95% of certificates created by SGUs, with micro hydro and micro wind volumes being negligible.

Figure 1 **Project data flow and models to be utilised**



Data source: ACIL Tasman

3 Financial payback analysis for solar PV

ACIL Tasman's analysis of the financial payback for solar PV technologies focused on three key drivers:

- Up-front subsidies and ongoing assistance (e.g. feed-in tariffs) available for solar PV systems through various government policies
- Retail electricity prices faced by households and small businesses (as primary installers of solar PV). This was built up using projections of the cost components including wholesale prices, retail costs, network costs and LRET/SRES charges
- Solar PV system costs and projected changes over time.

ACIL Tasman's core analysis of solar PV financial paybacks was undertaken in April, May and June 2011 using data on STC creation provided by the Office of the Renewable Energy Regulator (ORER) that was current in March 2011. However, ACIL Tasman updated the analysis during November 2011 to take into account various changes to feed-in tariff policies that occurred during the second half of 2011. The updated analysis presented here did not benefit from access to updated data on STC creation, take into account changes to PV system costs, or update retail electricity price projections to reflect the Commonwealth Government's carbon pricing policy announced in July 2011.

Given this analysis focuses on assessing the impact of changing policy settings on the uptake of solar PV systems, government policies were the primary driver of different scenarios used in the analysis.

Further, these policies vary materially between the states and territories and are a key driver of variations between estimated paybacks and solar PV uptakes in different jurisdictions. This is supported by the fact that a range of other variables that affect solar PV paybacks, such as electricity prices and levels of solar irradiation, vary between different locations.

Accordingly, the payback model and uptake projection was done on a state/territory specific basis.

The payback analysis also took into account the fact that different sized PV systems can have quite different financial paybacks because:

- Installation costs per kilowatt tend to reduce with system size (due to economies of scale and increased attractiveness to installers)
- The application of various government subsidies varies according to the installed capacity of the system (including the effect of the 'Solar Credits'

multiplier under the SRES and the application of various feed-in tariff eligibility caps)
- Systems of varying sizes have different export rates, and therefore different returns in jurisdictions with 'net' feed-in tariffs.

Given these key variables, the payback analysis consisted of assessing the financial payback of systems of seven 'typical' sizes, weighting these paybacks by their market share in each jurisdiction, and then projecting uptake of systems in three broader size bands: 0-1.5 kilowatts, 1.5-5 kilowatts and over 5 kilowatts.

3.1 Solar PV system scenarios

ACIL Tasman's projection of installation of, and STC creation by, solar PV systems was based on three primary scenarios and a Counterfactual Scenario. Other scenarios and sensitivities were undertaken as described below.

For the reasons discussed above, the primary drivers of these scenarios was variation in various government policy settings, including SRES policy settings, state/territory feed-in tariff policy settings and Commonwealth Government carbon pricing policy.

By contrast, assumptions about the change in solar PV system costs over time were the same across these scenarios to isolate the effect of policy adjustments.

The high level design of the three primary scenarios is as set out below:

- **'Core Scenario'**: this scenario was based on SRES and FiT policy settings as in place at the start of November 2011.
- **'Elevated Uptake Scenario'**: this scenario was based on the adjustment of various policy settings to support overall higher levels of STC creation by solar PV systems and included a carbon price as per the Carbon Scenario.
- **'Reduced Uptake Scenario'**: this scenario was based on the adjustment of various policy settings to lead to lower levels of STC creation by solar PV systems.

The Counterfactual Scenario was designed for consistency with the counterfactual being analysed in relation to the LRET for the AEMC. This involved analysing a situation where the original Mandatory Renewable Energy Target (MRET) remained in place with a target of 9,500 GWh by 2010, and where the SRES was not separated from the large-scale scheme.

Given the renewable investment that has already taken place, we considered that this would imply a REC price of zero. This scenario design would effectively result in there being no up-front subsidy via STCs/RECs (regardless of the multiplier, certificate prices are zero) and hence assistance for solar PV systems under this scenario relied solely upon feed-in tariffs.

This Counterfactual Scenario provided insights into the incremental impact of the Solar Credits policy upon uptake, retail electricity costs and abatement. However, the authors note that attributing abatement (or cost) to the SRES policy is conceptually difficult to the interaction of this policy with state-level policies (i.e. feed-in tariffs). These difficulties are outlined fully in section 6.4.

Additional scenarios and sensitivities analysed are as described below:

- **'Carbon Scenario'**: this scenario adopts all assumptions as per the Core Scenario, except that the Commonwealth Government is assumed to introduce a carbon price from 1 July 2012 that increases electricity prices, and therefore improves the financial return to solar PV systems. The carbon price used for this scenario was based on 2009 Treasury modelling for the CPRS with a 5% reduction target on year 2000 level emissions by 2020, rather than the carbon price series announced as part of, and modelled for, the Commonwealth Government's July 2010 *Clean Energy Future* policy.
- **'WA network sensitivity'**: this scenario adopts all assumptions as per the Core Scenario but adopts the WA Government's estimate of the long-term trend in electricity network costs in that state to 2020.

3.2 Assumptions around government assistance to solar PV systems

3.2.1 SRES policy settings

Policy settings within the SRES have a significant impact on the installation rates of solar PV systems and STC creation rates. The Solar Credits multiplier is a particularly important variable as it affects STC creation rates in two ways: firstly, it affects the rate of STC creation for any given solar PV installation by adjusting the number of STCs any given installation can create; secondly, it affects the financial attractiveness of solar PV systems and therefore the installation rate itself.

The Core Scenario adopted the reduced Solar Credits sequence announced by the Commonwealth Government on 5 May 2011, consisting of a reduction of the Solar Credits multiplier from 5 to 3 on 1 July 2011, to 2 on 1 July 2012, and to 1 from 1 July 2013 onwards.

Due to the recent nature of this change and the low probability of an upwards revision of the Solar Credits multiplier, this same sequence was adopted in the Elevated Uptake Scenario.

The Reduced Uptake Scenario considered a situation where the Solar Credits multiplier reduced from 3 to 1 on 1 July 2012 and remained at that level for the remainder of the projection.

These scenarios are presented in Table 1 below.

Table 1 **Assumed Solar Credits multiplier**

Scenario	To 30 June 2011	1 July 2011 to 30 June 2012	1 July 2012 to 30 June 2013	1 July 2013 to 30 June 2014	1 July 2014 onwards
Core	5	3	2	1	1
Elevated Uptake	5	3	2	1	1
Reduced Uptake	5	3	1	1	1
Carbon	5	3	2	1	1
WA network sensitivity	5	3	2	1	1

The rate at which a solar PV installation creates RECs/STCs is determined by the solar irradiation in that location and the expected average capacity factor achieved by the system. ORER defines four zones for calculating typical PV output per kilowatt of installed capacity as detailed in Table 2. Each Australian postcode is assigned a zone for this purpose.

Table 2 **ORER zone ratings**

Zone	Zone Rating
1	1.622
2	1.536
3	1.382
4	1.185

Data source: ORER

Table 3 shows the proportion of RECs historically created from each of the ORER zones by jurisdiction. The share of RECs created from each zone has been held constant within the projection.

Table 3 **Share of RECs created from Solar PV by jurisdiction, by zone**

Zone	ACT	NSW	NT	QLD	SA	TAS	VIC	WA	Australia
1			71%	30%				1%	8%
2			29%	1%	0%			5%	1%
3	100%	100%		70%	93%		25%	89%	70%
4					7%	100%	75%	4%	21%
All	100%	100%	100%	100%	100%	100%	100%	100%	100%

Note: Share of total RECs created from Solar PV over the period 2007 to 2010.
Data source: ACIL Tasman based on ORER data

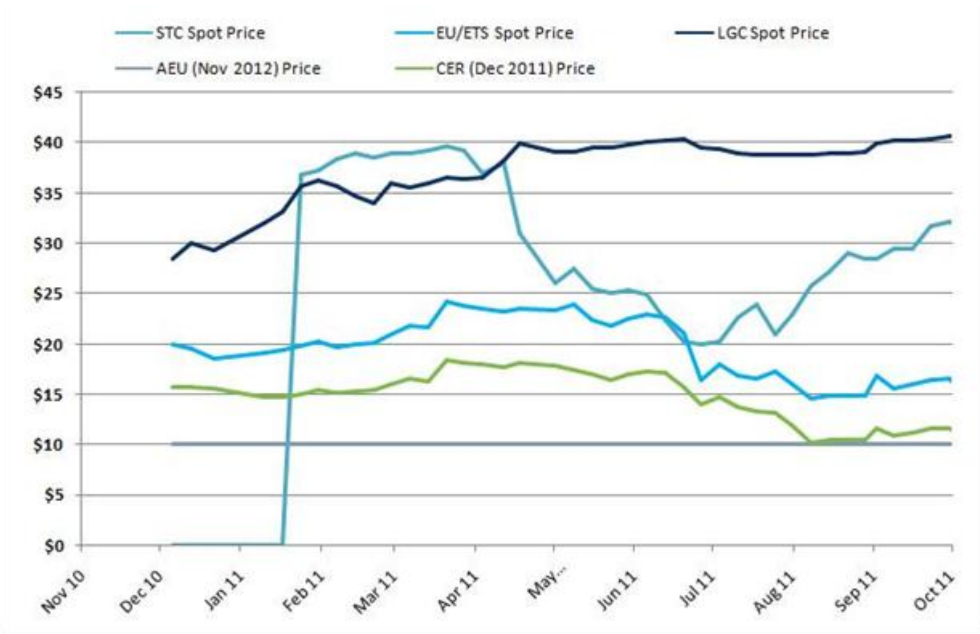
Another variable that affects the financial return of solar PV systems under the SRES is the STC price.

STCs are available for purchase and sale through a clearing house managed by ORER at a legislated fixed nominal price (presently $40/STC), but trade bilaterally at prices less than $40.

Despite the fixed clearing house price of $40, STCs have a traded in a broad range during 2011. STCs were initially trading at close to the $40 clearing-house price, but fell significantly to around $20 over the period April to June 2011 due to excess certificate supply and cash flow constraints of a number of installers. The reduction in STC creation rates following the July 2011 reduction in the Solar Credits multiplier has contributed to a firming of STC prices to a level of around $28 in early November 2011. It is not clear what proportion of certificates trade at prices below the $40 fixed price, nor for what period of time certificates are likely to trade at steep discounts to face value on the spot market.

For the purposes of this study we have abstracted away from these deep (likely transitory) discounts to capture the core long-run trend of current and alternate policy settings. Accordingly we have based net system cost calculations on the nominal clearing house price of $40/STC.

Figure 2 **Recent quoted STC spot price history**



Data source: Green Energy Markets, based on data from NextGen

The clearing house price is determined by section 30LA(1) of the *Renewable Energy (Electricity) Act 2001* (the REE Act). However, this section also provides that the relevant Minister may, by legislative instrument, adjust the clearing house price to be less than $40 at any time (the Minister cannot increase the price above $40 without Parliament amending the REE Act). In making such a change, the Minister must take into account, amongst other things, whether more than 6,000,000 STCs were, or are expected to be, created in 2015.

For the Core Scenario we have maintained the STC price at $40 for the entire analysis, even though one could read an intention into section 30LA of the REE Act that the STC price be reduced in the event that STC creation in 2015 exceeded or is considered likely to exceed 6,000,000. Similarly, the Elevated Uptake Scenario retains an STC price of $40.

For the Reduced Uptake Scenario, we propose material reductions in the STC price, taking effect from 2015. The basis of this assumption is that STC creation rates would be likely to exceed 6,000,000 in 2015 (i.e. after the Solar Credits multiplier has reduced to one) and beyond as PV system cost reductions continue to increase the attractiveness of this technology, and as SWH installations continue. Given the Solar Credits multiplier cannot be readily adjusted further, the simplest way for the Government to limit the cost of the SRES after 1 July 2013 is to reduce the STC price. The assumed extent of reduction is illustrated in Table 4 below.

Table 4 **STC price assumptions (Nominal $/certificate)**

Scenario	To 31 December 2014	1 January 2015 to 31 December 2019	1 January 2020 to 31 December 2024	1 January 2025 onwards
Core	$40	$40	$40	$40
Elevated Uptake	$40	$40	$40	$40
Reduced Uptake	$40	$30	$25	$20
Carbon	$40	$40	$40	$40
WA network sensitivity	$40	$40	$40	$40

3.2.2 Feed-in tariffs

Many state and territory governments in Australia have implemented feed-in tariffs to support the take-up of small scale solar PV systems.

A feed-in tariff entitles a household or business that installs a small-scale PV unit to earn a rate for the electricity they export to the grid (i.e. 'feed in' to the grid), usually at a premium to the retail electricity price. This premium rate subsidises the installation of PV units by offsetting the owner's up-front cost of purchasing a system more rapidly than if they were simply being paid the standard retail rate for electricity for their exported electricity, or a rate reflecting the variable cost of electricity consumption.

Some feed-in tariffs work on a 'gross' basis, where all electricity generated by the unit receives the premium rate, not just that which is fed in to the grid. This is a more generous arrangement for the owner and results in the unit's up-front capital cost being paid back faster. More typically, feed-in tariffs operate on a 'net' basis where the unit owner only receives the feed-in tariff on the amount of electricity exported to the grid (i.e. not including household consumption).

The level of the feed-in tariff and whether it is offered on a gross or net basis will materially affect solar PV uptake rates and therefore SRES compliance costs.

A range of announcements over the course of 2011 by various State and Territory governments have provided greater clarity around the potential for future changes to feed-in tariff regimes, tending to reduce the policy-driven bounds between the various scenarios analysed here.

Key announcements include:

- The South Australian Government's announcement on 6 April 2011 that its scheme would be closed as of 1 October 2011, and the June 2011 refusal of the South Australian Parliament to agree to the South Australian Government's proposed increase in its feed-in tariff from 44 cents/kWh to 54 cents/kWh. However, in June 2011, the South Australian Parliament also legislated a transitional 16 cents/kWh feed-in tariff to supersede the 44 cents/kWh regime, from 1 October 2011.
- The New South Wales Government's announcement on 28 April 2011 that its scheme would be closed from 29 April 2011.
- The Queensland Government's announcement on 10 May 2011 that it would cap the size of systems eligible for its feed-in tariff at 5 kilowatts from 6 June 2011
- The Western Australian Government's announcement on 20 May 2011 that its scheme will move from a 40 cents/kWh net feed-in tariff to a 20 cents/kWh net feed-in tariff from 1 July 2011, with an overall scheme cap of 150 MW. The Western Australian Government subsequently announced that the 150 MW cap had been reached and that therefore the 20 cents/kWh feed-in tariff would be closed from 1 August 2011.
- The Australian Capital Territory Government's announcement on 1 June 2011 that its small-scale feed-in tariff scheme was closed as of midnight the previous day. On 12 July 2011 the ACT's medium-scale solar feed-in tariff was opened to small-scale installations at the available rate of 30.3 cents/kWh. A rush of applications meant that this feed-in tariff was closed two days later, on 14 July 2011, once the medium-scale capacity cap of 15 MW had been reached.

- The Victorian Government's announcement on 1 September 2011 that it would close its 60 cents/kWh feed-in tariff as of 30 September 2011 (with systems needing to have been physically installed by this date), and the creation of a transitional feed-in tariff of 25 cents/kWh for installations occurring from 1 October 2011 (with the feed-in tariff being paid from 1 January 2012 to 31 December 2016).

In private discussions facilitated by the AEMC, the Queensland Government suggested an indicative capacity cap at which to close the Queensland feed-in tariff in the Reduced Uptake Scenario.

ACIL Tasman has also made assumptions about the potential introduction or extension of feed-in tariffs in Tasmania and the Northern Territory under the Elevated Uptake Scenario.

As part of the Core Scenario, ACIL Tasman assumed that all current feed-in tariff rates will be held constant in nominal terms for the life of the scheme, and that all other parameters will also be held constant (with the exception of WA's Renewable Energy Buyback Scheme rate, which we have assumed to increase with inflation).

The feed-in tariff assumptions modelled in the Core, Elevated Uptake and Reduced Uptake Scenarios are as set out below in Table 5 below.

Table 5 **Major Australian solar PV feed-in tariffs**

Jurisdiction	Scenario	Basis	Rate (cents/ kWh nominal)	Scheme start	Tariff paid until	Availability in financial analysis
NSW	Core	Gross	20	28 October 2010	December 2016	Closed from 29 April 2011
	Elevated Uptake					
	Reduced Uptake					
Victoria	Core	Net	60 'premium' FiT, then 25 'transitional' FiT	1 November 2009 for premium FiT; 1 January 2012 for transitional FiT	October 2024 for premium FiT; until 31 December 2016 for transitional FiT	Premium FiT until Q3 2011; transitional FiT until 75 MW capacity cap is reached or until Q4 2016
	Elevated Uptake					
	Reduced Uptake					
Queensland	Core	Net	44	1 July 2008	June 2028	Uncapped
	Elevated Uptake	Net	44	1 July 2008	June 2028	Uncapped
	Reduced Uptake	Net	44	1 July 2008	June 2028	Cap applied at 300 MW
South	Core	Net	44*	1 July 2008	June 2028	Premium FiT

Jurisdiction	Scenario	Basis	Rate (cents/ kWh nominal)	Scheme start	Tariff paid until	Availability in financial analysis
Australia	Elevated Uptake		'premium' FiT; then 16 'transitional' FiT	for premium FiT; 1 October 2011 for transitional FiT	for premium FiT; until 30 September 2016 for transitional FiT	closed from 1 October 2011; transitional FiT closed from 1 October 2013
	Reduced Uptake					
Western Australia	Core	Net	47 or 58.94** for premium FiT; then 27 or 38.94 transitional FiT	1 August 2010 for premium FiT; 1 July 2011 for transitional FiT	10 years from installation	Premium FiT closed from 1 July 2011; transitional FiT closed as of 1 August 2011
	Elevated Uptake					
	Reduced Uptake					
ACT	Core	Gross	45.7 for small-scale FiT, then 30.3 for medium-scale FiT	1 March 2009 for small-scale FiT; 12 July 2011 for medium-scale FiT	20 years from installation	Small-scale FiT closed from 1 June 2011; Medium-scale FiT closed from 14 July 2011
	Elevated Uptake					
	Reduced Uptake					
Tasmania	Core	Net	Retail price	2005	Ongoing	Uncapped
	Elevated Uptake	Net	44	1 January 2012	20 years from installation	Uncapped
	Reduced Uptake	Net	Retail price	2005	Ongoing	Uncapped
Northern Territory	Core	-	-	-	-	-
	Elevated Uptake	Net	44	1 January 2012	20 years from installation	Uncapped
	Reduced Uptake	-	-	-	-	-

** A feed-in tariff of 54 cents/kWh was assumed for some installations in South Australia to reflect the expected payback of systems installed after the South Australian Government's 30 August 2010 announcement that the feed-in tariff would be increased to this level. However, as part of the June 2011 legislation closing the original feed-in tariff and establishing a transitional 16 cents/kWh feed-in tariff, the original rate of 44 cents/kWh was sustained for all installations receiving the premium feed-in tariff.*

*** 27/47 cents/kWh applies for customers in the Synergy supply area; 38.94/58.94 cents/kWh applies in the Horizon supply area, consisting of the combined Solar Feed-in Scheme (initially 40 cents/kWh, reducing to 20 cents/kWh) and the applicable Renewable Energy Buyback Scheme rate for the relevant supply area. We assume that the Renewable Energy Buyback Scheme rates are indexed with inflation, while the Solar Feed-in Scheme rates are held constant in nominal terms.*

The key capacity caps applying in this analysis were the newly announced 5 kilowatt capacity cap in Queensland and the long-standing 5 kilowatt capacity cap in Victoria. All other capacity caps effectively exceed the maximum system size that has been analysed (7.5 kilowatts).

In addition to the closure of its feed-in tariff from 29 April 2011, the NSW Government also announced a retrospective reduction in the former 60 cents/kWh gross feed-in tariff to 40 cents/kWh from 1 July 2011. However, this change was never implemented.

In any case, ACIL Tasman did not taken the announcement into account in its payback analysis on the basis that the response of consumers to the financial incentives in place at the time the system is committed to be installed is the key parameter for analysis, not the actual realised value of the installation. Analysing the response of consumers to the NSW feed-in tariff scheme assuming fore-knowledge of this retrospective policy change would incorrectly assess the relationship between expected paybacks for consumers at the time of installation and the rate of uptake.

3.2.3 Export rates

A key variable affecting the return delivered by solar PV systems under a feed-in tariff arrangement is the proportion of the electricity the system generates that is exported (the 'export rate').

Export rates will tend to vary by size of system (as generation from larger systems will be more likely to exceed consumption at any given moment in time, all other things being equal) and location (locations where sunshine is less correlated to household demand will tend to produce higher export rates).

ACIL Tasman has adopted export rates that are slightly lower for very large systems, on the assumption that these installations are more likely to occur at larger premises such as commercial premises, with greater electricity usage during daylight hours. Reflecting this, ACIL Tasman's assumed export rates are set out in Table 6.

Table 6 **PV export rate assumptions**

Jurisdiction	0.8 kW	1.1 kW	1.6 kW	2.1 kW	2.8 kW	3.2 kW	4.4 kW	7.5 kW
NSW	15%	20%	25%	35%	45%	55%	50%	50%
Victoria	10%	15%	20%	30%	40%	50%	40%	40%
Queensland	20%	25%	30%	40%	50%	60%	50%	50%
South Australia	15%	20%	25%	35%	45%	55%	50%	50%
Western Australia	20%	25%	35%	40%	50%	55%	50%	50%
Tasmania	10%	15%	20%	30%	40%	50%	40%	40%
Northern Territory	20%	25%	30%	40%	50%	60%	50%	50%
ACT	15%	20%	25%	35%	45%	55%	50%	50%

Data source: ACIL Tasman assumptions.

3.3 Retail electricity prices

To assess the payback of solar PV systems over their life for a projection period ending in 2020, ACIL Tasman examined the return for systems installed in 2020. Using an assumed system life of 25 years, this required a projection of retail electricity prices to 2045 (although later years in this projection have a decreasing impact on results due to the effect of discounting).

Reflecting this requirement, the discussion of our retail price projection below refers to two separate periods:

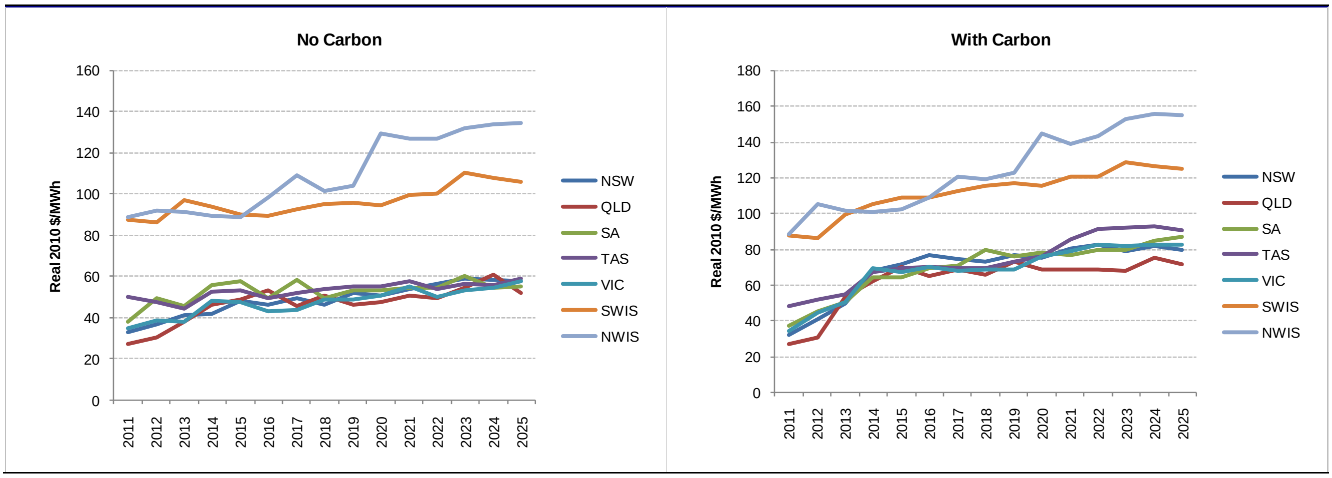
- The 'projection period' to 2020, over which installation levels, retail price effects and emissions abatement are estimated
- The 'payback analysis period' to 2045, which was chosen to allow assessment of the payback of solar PV systems installed in 2020 over their full operating life.

ACIL Tasman built up retail electricity prices over the payback analysis period from their components, necessitating assumptions about each component. These are outlined below.

3.3.1 Wholesale electricity prices

Wholesale electricity prices were extracted from ACIL Tasman's *PowerMark* modelling, with the price path being dependent on the carbon price scenario chosen (see Figure 3).

Figure 3 **Projected wholesale electricity costs by region**



Note: Time-weighted average prices (i.e. do not include retail uplift factors or retail hedging costs). The carbon price series modelled was current as of June 2011 and so did not take into account the Commonwealth Government's announcement of 10 July 2011 on its *Clean Energy Future* policy.

Data source: ACIL Tasman PowerMark modelling

Time-weighted pool prices were adjusted to derive a wholesale energy component applicable to small customers that better reflects the typical correlation of small customer loads to pool prices. These 'retail load uplift factors' are assumed to be higher in the absence of a carbon price due to the general trend that less emissions-intensive generators tend to operate more in peak periods (when retail load is higher).

Table 7 **Retail load uplift factors**

Jurisdiction/network	Retail load uplift factor (no carbon)	Retail load uplift factor (with carbon)
New South Wales	125%	115%
Victoria	145%	130%
Queensland	115%	110%
South Australia	165%	140%
Western Australia (SWIS)	140%	125%
Western Australia (Horizon)	125%	115%
Tasmania	120%	115%
Northern Territory	125%	115%
Australian Capital Territory	130%	120%

Data source: ACIL Tasman assumptions

Additional costs were assumed to reflect the inherent uncertainty in market outcomes and the price risk faced by retailers in supply small customer loads that cannot be directly controlled and tend to be correlated with market price spikes. The costs of this uncertainty goes beyond the uplift factors estimated above (which reflect ex post assessments of the correlation of small customer load with market outcomes), but rather reflects the potential for extreme price events over and above those that have been observed or that are likely to occur. Accordingly, the retail hedging cost applied in each jurisdiction most closely reflects the variation in market price outcomes and potential for extreme market price events. Reflecting this, South Australian hedging costs are particularly high (given the sensitivity of that market to heat waves and other price events), whilst hedging costs in the Western Australian South West Interconnected System (SWIS) are very low (reflecting the design of that particular market and the operation of capacity credits rather than peak price signals to deliver new capacity).

Table 8 **Retail hedging costs**

Jurisdiction/network	Retail hedging costs (no carbon)	Retail hedging costs (with carbon)
New South Wales	125%	115%
Victoria	125%	115%
Queensland	125%	115%
South Australia	140%	130%
Western Australia (SWIS)	105%	105%
Western Australia (Horizon)	110%	105%
Tasmania	125%	115%
Northern Territory	110%	110%
Australian Capital Territory	125%	115%

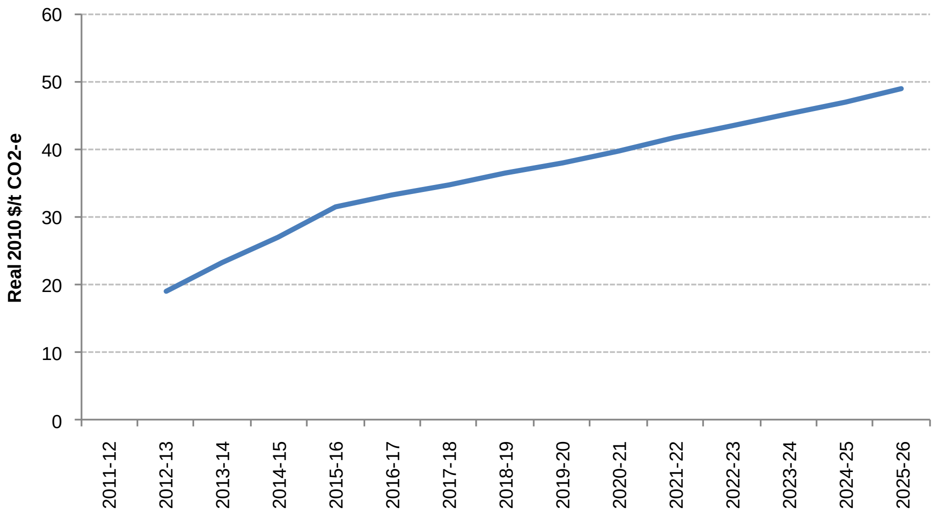
Data source: ACIL Tasman assumptions

3.3.2 Carbon pricing

The Core Scenario did not include a carbon price on the basis that this scenario involves a strict continuation of current policies, and uncertainty remains around the implementation of a carbon price. The Reduced Uptake Scenario also did not include a carbon price on the logic that the absence of a carbon price would be one factor contributing to a lower bound take-up of solar PV systems. However, the Elevated Uptake Scenario and the Carbon Scenario included a carbon price.

The wholesale electricity market modelling underpinning the Elevated Uptake and Carbon scenarios was completed in June 2011 and was not updated in parallel with the updated feed-in tariff knowledge for this November 2011 report. Accordingly, these scenarios did not take into account the detail of the carbon price series announced by the Commonwealth Government on 10 July 2011 as part of its *Clean Energy Future* policy announcement. Figure 4 shows the carbon price assumed for the Carbon and Elevated Uptake scenarios.

Figure 4 **Carbon price assumed for carbon scenarios**



Note: Pricing assumed to commence 1 July 2012 with a three year fixed price series, transitioning to an emissions trading scheme with a floating carbon price in 2015-16. The carbon price series modelled was current as of June 2011 and so did not take into account the Commonwealth Government's announcement of 10 July 2011 on its *Clean Energy Future* policy.

Data source: ACIL Tasman assumptions drawing on Commonwealth Treasury modelling

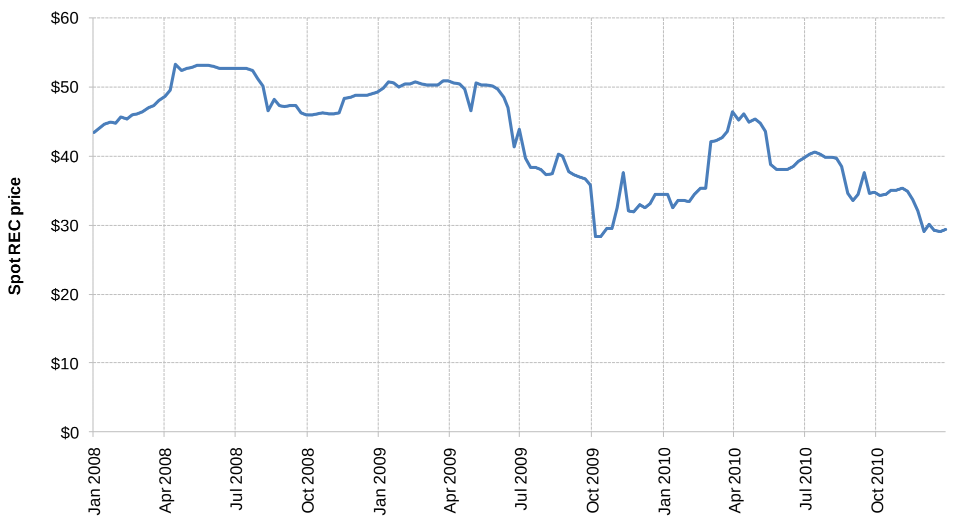
3.3.3 REC/LGC prices

Although Large-scale Generation Certificate[2] (LGC) prices do not directly affect the subsidy available to small solar PV systems (as they can only be created by large-scale renewable generators), LGC prices and liabilities determined under the LRET affect retail electricity prices and therefore paybacks to solar PV systems.

Historic REC prices affect the historic return to solar PV systems (as PV installations occurring up until 31 December 2010 created RECs and earned a financial return that depended on their market price). The relevant REC price data for this purpose was drawn from data published by the Australian Financial Markets Association (AFMA), as shown in Figure 5.

Future LGC prices were drawn from ACIL Tasman modelling using *RECMark*, our least-cost optimising model of the Large-scale Renewable Energy Target (LRET) policy. Projected certificate prices under the 'with' and 'without' carbon scenarios are shown in Figure 6. The LRET is not projected to be met under either scenario with shortfalls occurring in 2024 with carbon and as early as 2019 under a no carbon scenario.[3]

Figure 5 **Historic REC prices**

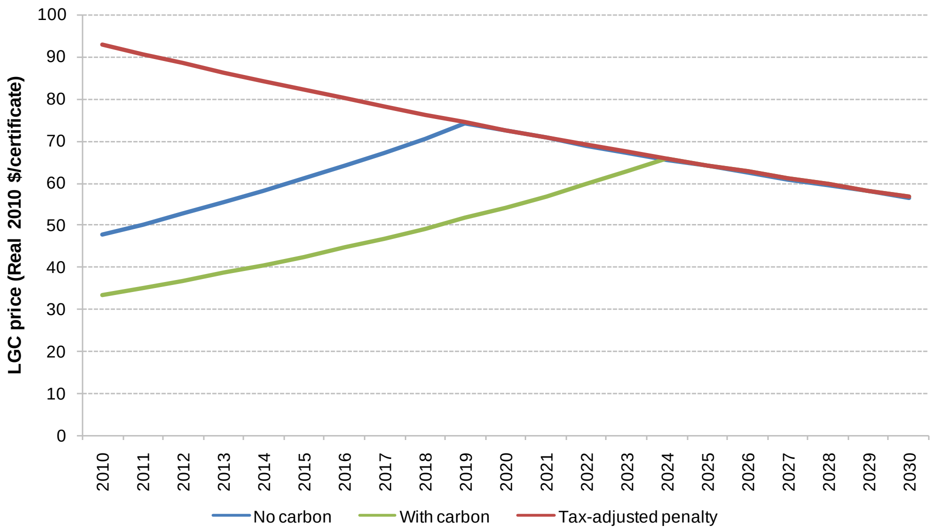


Data source: AFMA Environmental Products Curve.

2 LGCs are the equivalent of RECs under the new Large-scale Renewable Energy Target, which, in combination with the SRES, are the successor schemes of the former Renewable Energy Target policy.

3 *RECMark* allows the payment of the tax-adjusted penalty as a viable commercial strategy and does not attribute any additional 'reputational' costs for liable parties.

Figure 6 **Projected LGC prices**



Data source: ACIL Tasman, *RECMark* modelling

3.3.4 Network pricing

ACIL Tasman estimated network (transmission and distribution) elements of retail electricity prices on broadly the following basis:

- relevant customer load profiles (i.e. average annual usage, peak/off-peak usage) for target customer groups were assumed
- historic published network use of system charges were used to estimate applicable tariffs
- historic tariffs were then grown in line with the revenue requirements set out in published network determinations, adjusted for projected load growth (this approach implicitly assumes that there will be no changes to relative tariffs between customer classes)
- where applicable, tariffs for multiple networks in a given jurisdiction were weighted according to their overall customer shares in the target customer class to give a jurisdiction-level average network tariff
- assumed real growth factors were then applied to the derived network price estimates from the end of the regulatory determination period over the remainder of the payback analysis period.

A key assumption considered in developing the retail price projection was the level of real growth in network prices beyond the current regulatory determination period.

Given the inherent uncertainty of the rate of network cost increases over that period, one approach considered was to vary the rate of network cost increase between scenarios to test the potential effects. However, this would have tended to blur and increased the complexity of isolating the effect of policy on uptake rates.

Accordingly, ACIL Tasman adopted a core assumption of zero real network cost increases from the end of the current regulatory determinations, other than in WA, where the imminent end of regulatory determinations in those states would tend to distort results in that state by potentially underestimating future levels of network tariffs. This approach was adopted across the Core, Elevated Uptake, Reduced Uptake and Carbon scenarios to isolate the effect of policy changes.

In relation to WA, the Office of Energy provided estimates of future network cost escalations to 2019-20 to assist in estimates for that state. The Office of Energy estimates were based on an inflation assumption of 3-3.25%, which was not consistent with ACIL Tasman's nation-wide inflation assumption of 2.5%. Accordingly, the Office of Energy estimates were adjusted to normalise the inflation assumption. The normalised estimates were adopted up to and including 2014-15 for all primary scenarios, whilst the effect of adopting the full sequence to 2019-20 was analysed in the 'WA network' sensitivity.

Table 9 **WA network real cost escalation assumptions**

Scenario	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Core	7.1%	7.4%	6.3%	0%	0%	0%	0%	0%
WA network sensitivity	7.1%	7.4%	6.3%	20.9%	6.8%	6.8%	20.9%	6.8%

Data source: WA Office of Energy; ACIL Tasman adjustments to normalise inflation assumption.

3.3.5 Retail operating costs

ACIL Tasman reviewed retail operating costs in several regulated jurisdictions to benchmark retail operating costs. These have been estimated as an approximate cost per megawatt-hour (based on average customer loads) to reflect that, while costs per customer are largely constant regardless of usage, these retail operating costs tend to be allocated as a variable component of retail tariffs.

The IPART determination of NSW regulated retail tariffs implied retail operating costs of just over \$16/MWh (in 2010-11 dollars) based on assumed average annual consumption of 7 MWh. LECG's recent review of retail operating costs in South Australia implies total retail operating costs of around \$18/MWh (in March 2011 dollars) based on an average annual consumption of 6.7 MWh. The QCA's final decision on the Queensland Benchmark Retail Cost Index (BRCI) implies retail operating costs of around \$16.80/MWh (in 2010-11 dollars) based on assumed annual consumption of 7.5 MWh/year.

On the basis of this analysis, ACIL Tasman adopted nation-wide retail operating costs of $17/MWh in January 2011 dollars, and held these retail operating costs constant in real terms over the course of the analysis.

3.3.6 Retail margin

Regulators have typically allowed a retail margin in the order of 5% of total costs (excluding the margin itself) when setting regulated tariffs for small customers. Examples of this include:

- IPART's 2010-13 determination for the NSW retailers allowed a margin of 5.4% of total costs
- QCA's 2010-11 BRCI allowed a margin of 5% of total costs
- ESCOSA's 2010 Review of the Retail Electricity Standing Contract Price Path allowed a margin of 10% of wholesale energy and retail operating costs, which equates to around 5.3% of total costs.

Accordingly, ACIL Tasman maintained a constant retail margin of 5% of total costs.

3.3.7 Feedback of FiTs into retail electricity prices

As part of the projection, ACIL Tasman considered the effect of feed-in tariffs on retail tariffs, and the extent to which this would 'feedback' to support higher solar PV uptake and higher feed-in tariff costs.

This dynamic was not a factor in NSW, as ACIL Tasman has interpreted NSW Government policy statements as representing a clear commitment to insulate retail electricity tariffs from the impact of its feed-in tariff.

The dynamic was also not a factor in Victoria, as the premium feed-in tariff costs are incorporated into the fixed supply charges levied by network businesses. ACIL Tasman's payback model has focused on the variable component of retail electricity prices (see section 3.3.8 below), and so the effect of the feed-in tariff on retail tariffs does not support a further feedback to uptake rates.

In other jurisdictions, notably Queensland, South Australia and the Australian Capital Territory, ACIL Tasman has estimated the level of feed-in tariff costs already captured in current network tariffs, and netted this cost of the estimated gross cost of the feed-in tariff. Retail electricity prices were then increased or reduced by the net difference in modelled cost.

3.3.8 Application of retail electricity prices

Where a consumer installs a photovoltaic system and consumes electricity produced by their own system, ACIL Tasman has assumed that this production is netted off the consumption to effectively reduce the quantity of electricity purchased by the consumer from their retailer. In this circumstance, the avoided cost (and therefore financial reward) to the consumer is equal to the *variable component* of the retail tariff they pay. Based on currently prevailing tariff structures, this variable component is typically in the order of 90% of the total per unit cost, resulting a strong financial return from 'own consumption' electricity.

However, where the PV system exports electricity *in the absence of a feed-in tariff*, further judgements are required as to what financial return the consumer will receive (where a feed-in tariff is in place, the consumer will be paid for their electricity at the rate of the feed-in tariff).

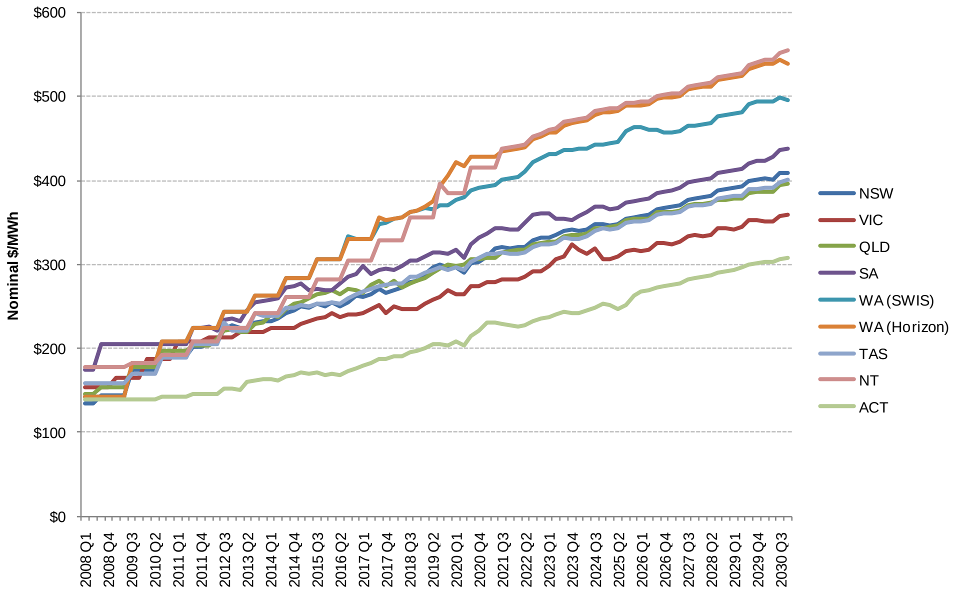
Given the existence of 'standard' feed-in tariffs in Victoria and Tasmania (which effectively guarantee that "the amount you pay to consume electricity from the grid is the same amount you receive when your solar PV system generates power and that is fed back into the grid"[4]), for these jurisdictions, ACIL Tasman adopted the approach of assuming that exported electricity receives the variable component of the prevailing electricity tariff when no feed-in tariff is in place.

For other jurisdictions, ACIL Tasman has assumed that exported electricity receives the 'economically avoidable' component of retail charges in the absence of a feed-in tariff. We estimated this component as consisting of wholesale energy (including carbon) and hedging costs, and variable 'green scheme' costs. Retail operating costs, retail margins and network costs can be broadly categorised as not being economically avoidable.

Figure 7 and Figure 8 show the retail electricity prices applied under this methodology for the no carbon and with carbon scenarios respectively.

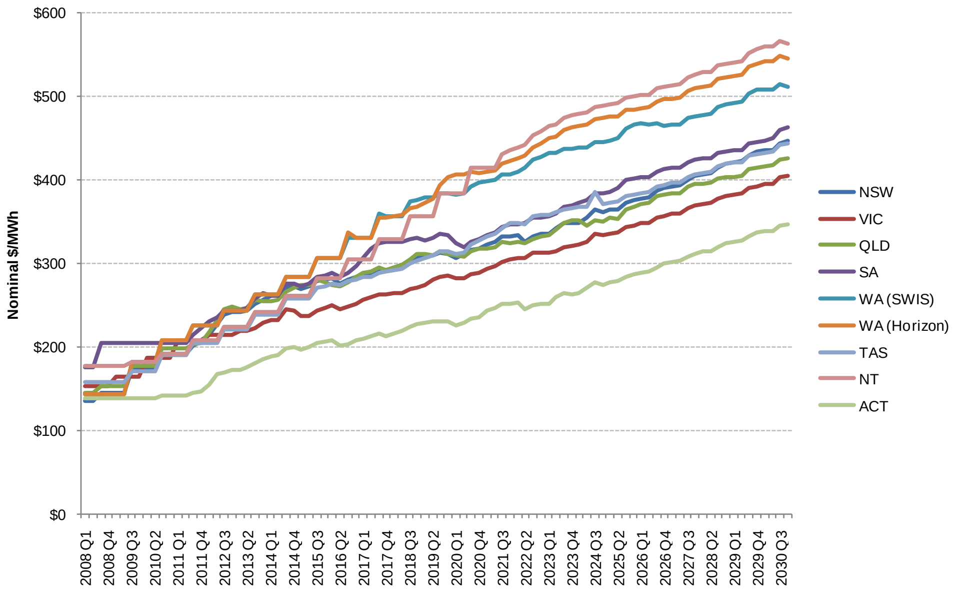
[4] http://new.dpi.vic.gov.au/energy/policy/greenhouse-challenge/feed-in-tariffs/feed-in-tariffs-faq/standard-feed-in-tarrifs-faq; accessed 15 March 2011.

Figure 7 **Retail electricity price by jurisdiction: No carbon**



Note: Variable components of retail price only. Excludes GST.
Data source: ACIL Tasman analysis

Figure 8 **Retail price by jurisdiction: With carbon**



Note: Variable components of retail price only. Excludes GST.
Data source: ACIL Tasman analysis

3.4 System costs

ACIL Tasman's analysis of system costs drew on a literature review of system cost components, focusing particularly on:

- module costs

- inverter costs
- installation costs.

This analysis occurred during April 2011 and was not updated for the November 2011 finalisation of this analysis in response to changes to feed-in tariff policy settings.

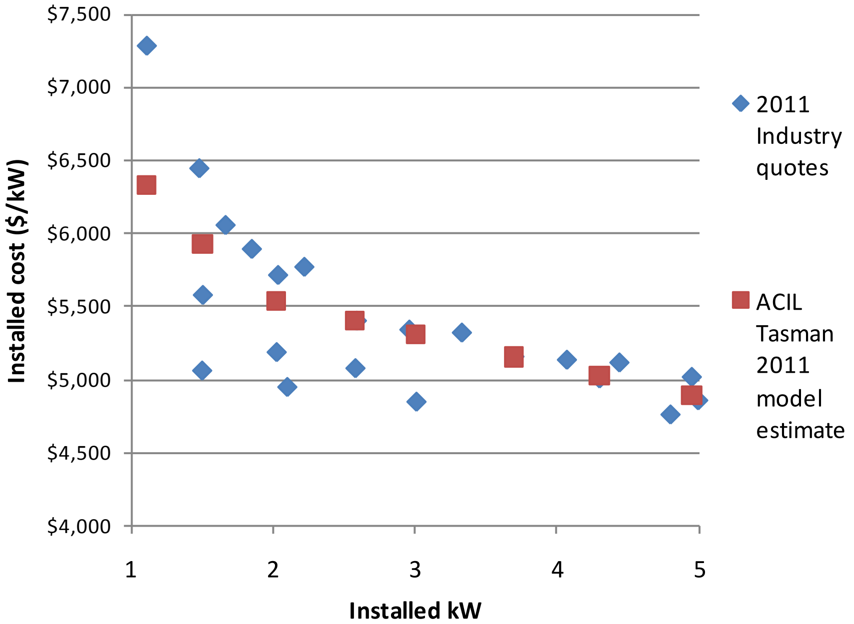
Key cost assumptions were as below:

- Retail module costs were assumed to start at 3.19 USD/kW for March 2011 based on SolarBuzz[5] data
- Wholesale module costs were assumed to consist of 85% of the retail module cost
- Real module costs were assumed to decline at a rate of 5.5% per year based on an annual growth rate of module production of 22% per year (European Photovoltaic Industry Association) and a learning rate of 18% (i.e. costs reduce 18% for every doubling of installed capacity) (Hearps and McDonnell for the Garnaut Review, March 2011)
- Retail inverter costs were assumed to start at 0.715 USD/kW in March 2011 (SolarBuzz), with wholesale cost consisting of 85% of retail cost
- Minimum size of low cost inverters of 2 kW, with 1 kW inverters available at 1 USD/kW
- Inverter costs reducing by 3% real per annum (based on GreenEnergy assumptions used in November 2010 analysis for the Office of the Renewable Energy Regulator)
- A constant USD/AUD exchange rate of 1
- Balance of system costs varying between 5% and 8% of 2011 module costs, declining with system size (based on calibration to 2011 Australian system cost quotes)
- Balance of system costs declining at 0.8% per year (reflecting that these components are largely mature)
- Labour costs varying between 15% and 22% of 2011 module costs, declining with system size (based on calibration to 2011 Australian system cost quotes)
- Labour efficiency improving at 2% per annum, partially offset by real skilled labour costs increasing at 1.4% per annum (ACIL Tasman estimates)
- Regulatory compliance and overhead costs and profit margins on installation decreasing from 30% to 15% of total system cost, declining with system size.

[5] Solarbuzz is a global market research and consulting firm specializing in the solar energy supply chain (see www.solarbuzz.com)

The cost assumptions delivered a variation in system cost by system size that fit well with 2011 system cost quotes analysed, as shown in Figure 9.

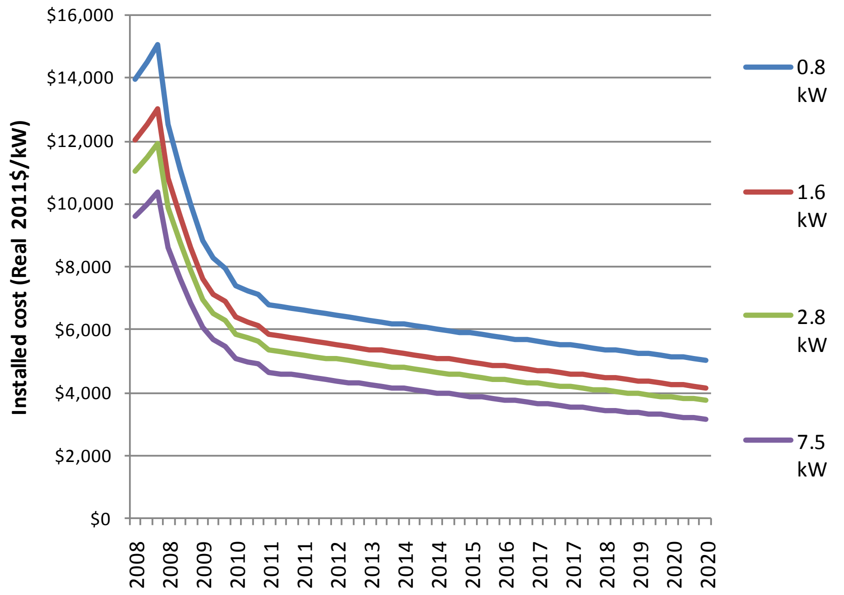
Figure 9 **April 2011 variation in installed system cost by size**



Source: Clear Solar, Going Solar and Solaronline installed system quotes; ACIL Tasman model assumptions

The core assumptions surrounding reductions in module, inverter and balance of system costs result in a strong real decline in system costs to 2020, particularly when compared to high pre-2009 system costs.

Figure 10 **Real system costs by system size, 2008 to 2020**



Source: ACIL Tasman analysis

Slight adjustments were also made to labour cost assumptions based on labour market conditions: labour costs were assumed to be 130% of the base assumption in northern WA, 110% in south-west WA and the NT, 90% in lower cost jurisdictions South Australian and Tasmania, and 100% elsewhere.

Once installed, the output of a system is assumed to degrade by 0.5% per year. System life was assumed as 25 years, with inverters replaced every 10 years.

3.5 Discount rate

Whilst it is highly unlikely that a typical household or small commercial entity would formally apply a discount rate to assess the financial implications of a PV installation, consumer behaviour strongly supports the idea that early paybacks or upfront subsidies that reduce 'out of pocket' costs have a strong impact on installation rates. Whilst the mechanism to deliver this outcome is not a formal discounted payback analysis, a modelling approach such as that adopted here can reasonably infer that consumers prefer to receive benefits earlier rather than later and have sufficient information to respond to returns delivered over different timeframes. Accordingly, it is also reasonable to assume that consumer behaviour will be related to discounted financial returns rather than, say, undiscounted financial returns.

It is also relevant to note that the modelling approach adopted implicitly assumes a well-informed financial assessment takes place, which is a challenging exercise requiring complex assessment of a range of changing energy market and policy variables. This being the case, the choice of discount rate should be considered in the context of developing a payback series that is most likely to have explanatory power in relation to past and future consumer behaviour, not replicating the precise method by which consumers would analyse system return and make installation decisions (as consumers would not replicate the type of analysis undertaken here).

Consistent with this approach, rather than adopting a particular assumed discount rate, the rate was informed by the econometric analysis (discussed in the subsequent section). The regressions tested a range of discount rates from 7.5% through to 15%, in an attempt to find the rate which best explained the level of historical uptake actually observed. The rate which provided the best fit with the historical data was 10% nominal. This rate was used throughout the analysis.

3.6 Financial payback results

The financial payback indicator relates to the net present value (NPV) of economic flows resulting from the installation of a solar PV system. Where this value is positive it suggests the household is financially better off – a negative value indicates the economic returns will not offset the upfront out-of-pocket expenses on a discounted basis.

The economic return of a solar PV system comprises:

- avoided electricity charges for own consumption (these relate to variable components of a households electricity bill)
- payments for own consumption (only applicable under gross FiT schemes)
- payments for exported electricity (applicable for both gross and net FiT schemes, and where no FiT is in place).

These returns need to offset the upfront out-of-pocket expenses incurred, plus any ongoing costs relating to the solar PV system (i.e. replacement of inverter, maintenance, etc.).

For periods up to quarter 2, 2009 the financial payback series reflects the cash subsidies provided by the former Solar Homes and Communities Plan. After this time, paybacks reflect the subsidy provided through the Solar Credits policy. Payments for FiT schemes are applied to the output of installations in the relevant periods, subject to capacity caps. The financial payback indicator is calculated for 8 different system sizes in each jurisdiction and weighted according to shares of historical uptake. They are calculated at a quarterly resolution.

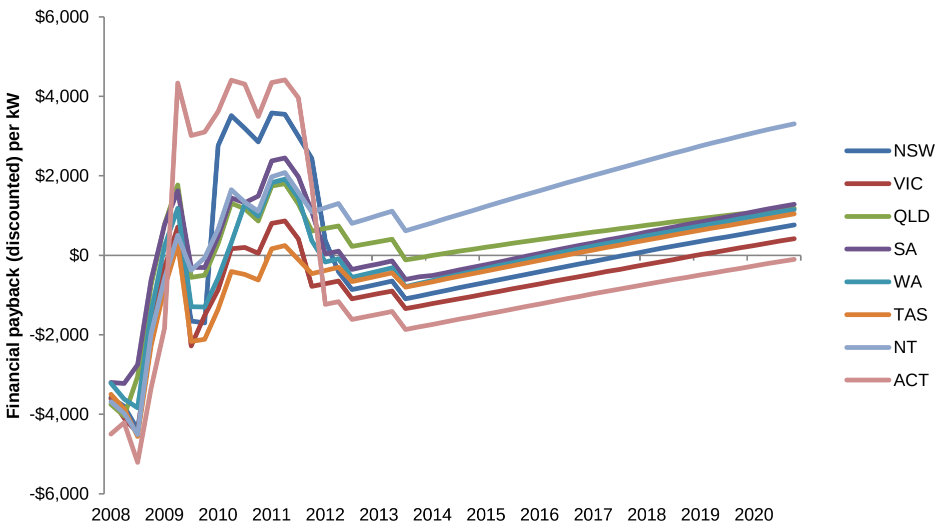
All paybacks shown below reflect the expected payback at the date of installation (although the financial return reflects expected outcomes over the life of the system). In other words, the total return of the system is discounted to a single value as of the date of installation, and the payback charts below illustrate how expected discounted returns vary in relation to different installation.

3.6.1 Core Scenario

Figure 11 shows the resulting financial paybacks under the Core Scenario for each jurisdiction. Initially paybacks are low with results for all jurisdictions falling in the -$3,000 to -$5,000 range. However, the drop in system costs, combined with the introduction of Solar Credits and jurisdictional FiT schemes changes the paybacks dramatically. The ACT and NSW have the highest paybacks – a result of the gross FiT schemes in place in these regions. For installations in early 2011, the financial paybacks are positive across all jurisdictions.

Paybacks fall in line with the reduction in Solar Credits multiplier and also the capping of FiT schemes. It should be noted that in some instances for the purpose of the payback indicator the FiT component was allowed to continue for several quarters beyond its closure date to account for the lag between accepted FiT applications and installation/certificate creation.

Figure 11 **Financial payback results: Core Scenario**



Note: Financial payback using a nominal discount rate of 10%

Data source: ACIL Tasman analysis

In the Core Scenario, paybacks reach their low point for installations in mid 2013 when the Solar Credits multiplier falls to 1 and most FiT schemes have reached their stated cap. Paybacks improve from this point – driven by the projected ongoing decline in system costs and rising retail electricity prices in the period to 2020 as follows:

- PV system costs projected to decline by around 27% in real terms
- retail electricity prices (variable components only) expected to be 20% above current levels in real terms.

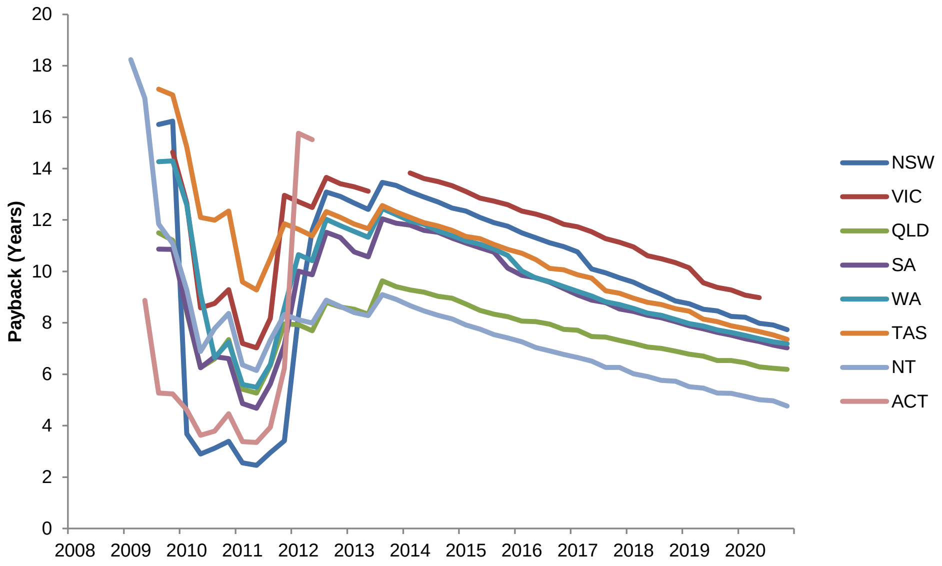
By 2020 paybacks on new solar PV systems are approaching current levels and are positive for all jurisdictions except the ACT.

Another way of expressing payback period is in years it takes to recoup the original out-of-pocket costs. When expressed in this fashion, future income streams are not discounted at all. The payback period in years is shown in Figure 12 for each jurisdiction. The first half of 2011 represents a low point in this series with payback periods of:

- 3-4 years for NSW/ACT
- 5-7 years for SA, QLD, WA, NT and VIC
- 10 years for TAS.

Payback periods increase with the scheduled reductions in the Solar Credits multiplier, but begin to fall for installations in later years and aren't significantly different from the 2011 low point by 2020. This indicates that while current installation rates are not sustainable because they are being driven by subsidies, the economics of PV systems will improve over time, such that paybacks in 2020 will not appear significantly different from the current, heavily subsidised levels.

Figure 12 **Payback expressed in years: Core Scenario**



Note: Time required to recoup of-out-pocket costs (undiscounted). Breaks in the series indicate payback does not occur.

Data source: ACIL Tasman analysis

The following sections show the financial payback and payback time under each of the scenarios examined. In most cases (aside from the Counterfactual Scenario which does not include SRES) the financial paybacks follow a similar path albeit at slightly different levels.

At the outset of this project, the scenario design included some large differences between the Core, Elevated and Reduced Uptake scenarios. However, throughout the project there were a number of announced changes to FiT schemes which narrowed the scenario definitions significantly.

Variations within the paybacks between scenarios are attributable to differences in:

- Solar Credits multiplier reduction timing
- STC clearing house price
- FiT scheme rates and caps
- Retail electricity prices.

Differences in paybacks between jurisdictions are attributable to differences in:

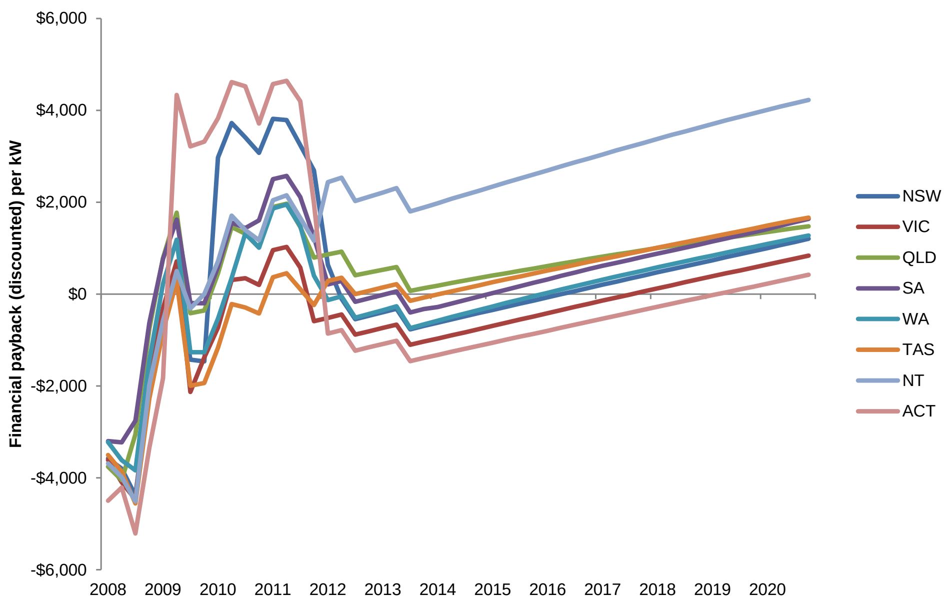
- Solar irradiation, and therefore the total number of STCs created per installation, and the total output of each installation
- FiT schemes and caps
- Assumed policies towards the return to consumers from exported electricity in the absence of a FiT

- Retail electricity prices
- Labour installation costs for PV systems.

The PV system cost projection and discount rate have been held constant across all of the scenarios examined.

3.6.2 Elevated Uptake Scenario

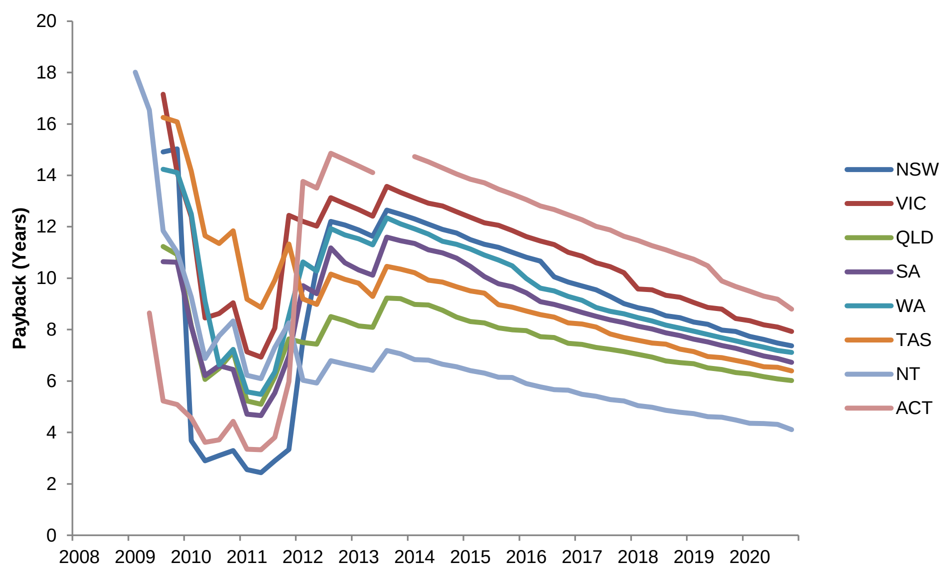
Figure 13 **Financial payback results: Elevated Uptake Scenario**



Note: Financial payback using a nominal discount rate of 10%

Data source: ACIL Tasman analysis

Figure 14 **Payback expressed in years: Elevated Uptake Scenario**

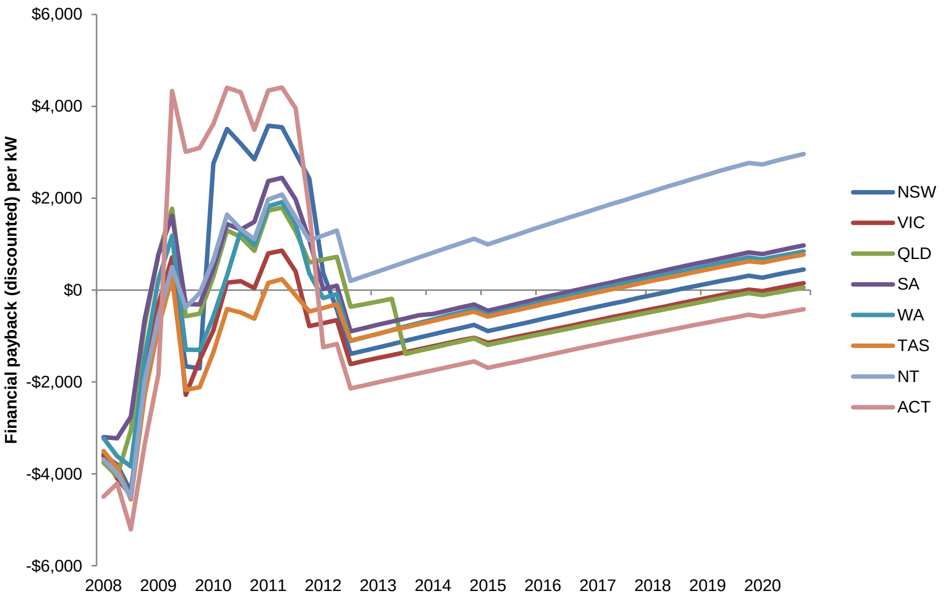


Note: Time required to recoup of-out-pocket costs (undiscounted). Breaks in the series indicate payback does not occur.

Data source: ACIL Tasman analysis

3.6.3 Reduced Uptake Scenario

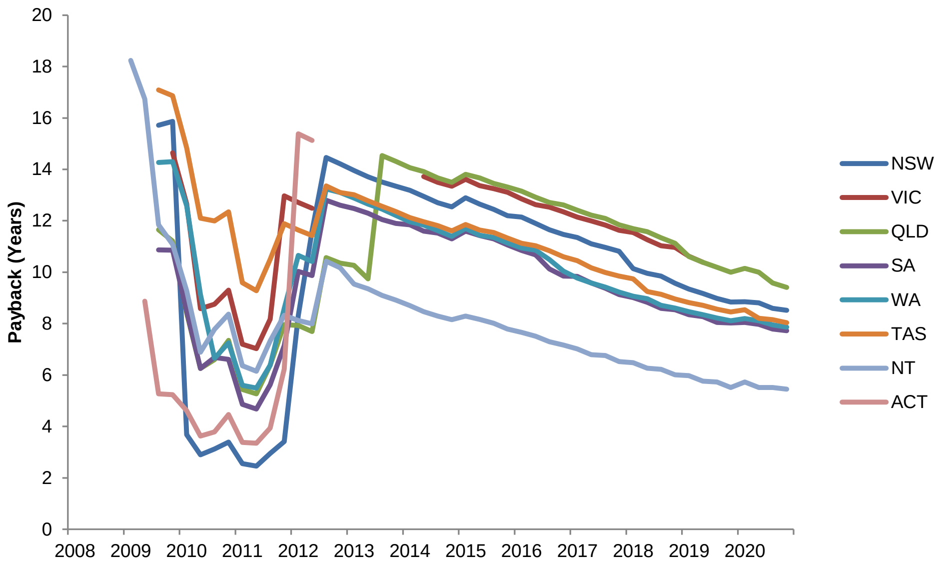
Figure 15 **Financial payback results: Reduced Uptake Scenario**



Note: Financial payback using a nominal discount rate of 10%

Data source: ACIL Tasman analysis

Figure 16 **Payback expressed in years: Reduced Uptake Scenario**

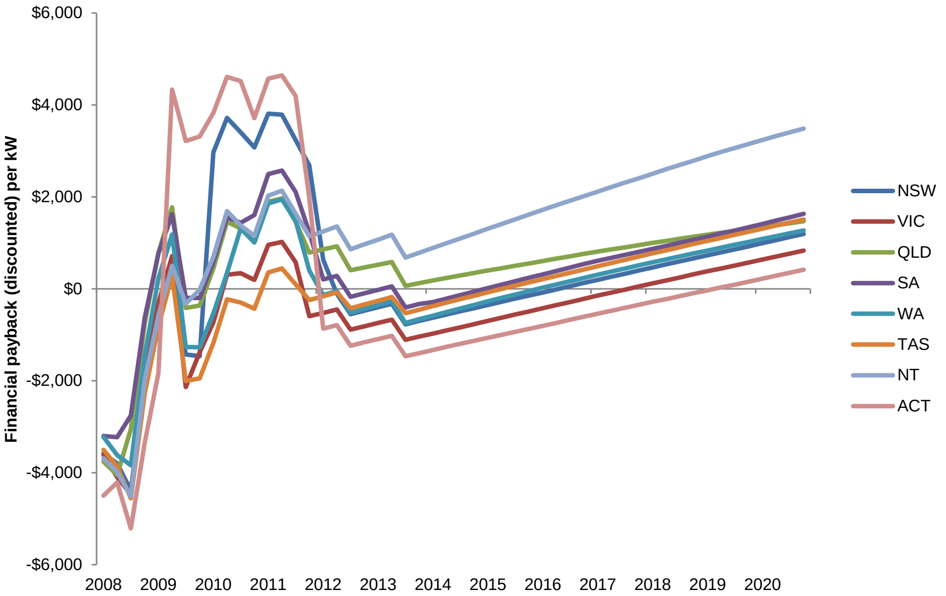


Note: Time required to recoup of-out-pocket costs (undiscounted). Breaks in the series indicate payback does not occur.

Data source: ACIL Tasman analysis

3.6.4 Carbon Scenario

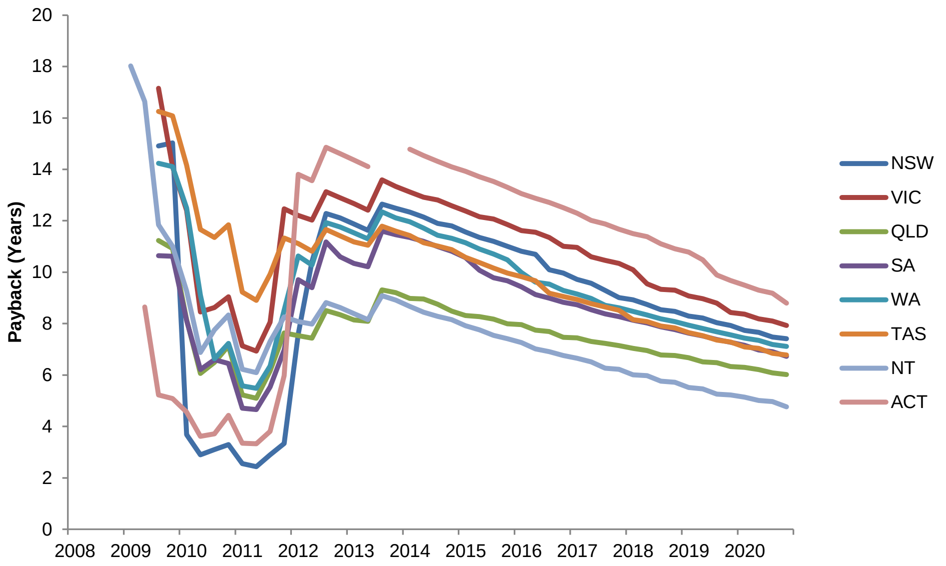
Figure 17 **Financial payback results: Carbon Scenario**



Note: Financial payback using a nominal discount rate of 10%

Data source: ACIL Tasman analysis

Figure 18 **Payback expressed in years: Carbon Scenario**

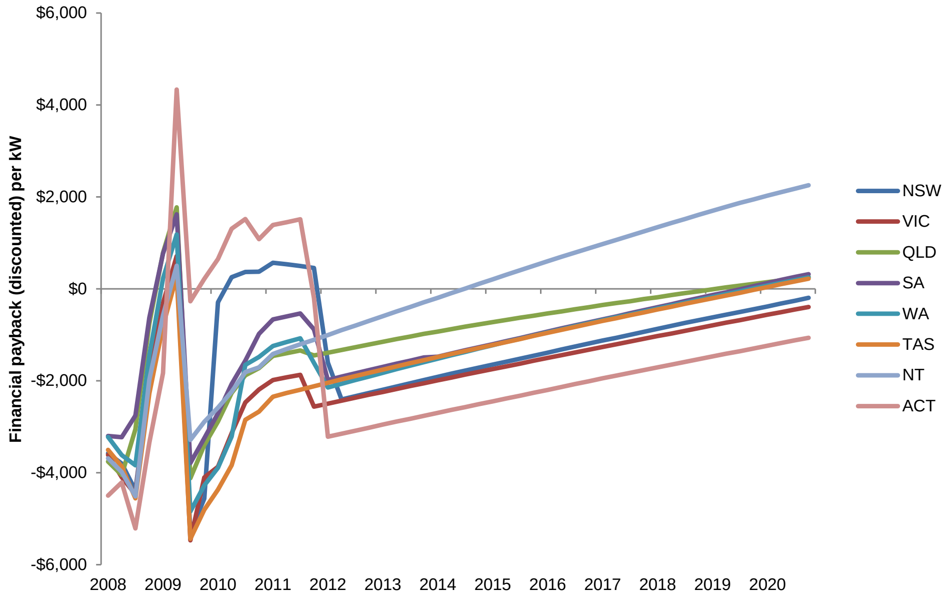


Note: Time required to recoup of-out-pocket costs (undiscounted). Breaks in the series indicate payback does not occur.

Data source: ACIL Tasman analysis

3.6.5 Counterfactual Scenario

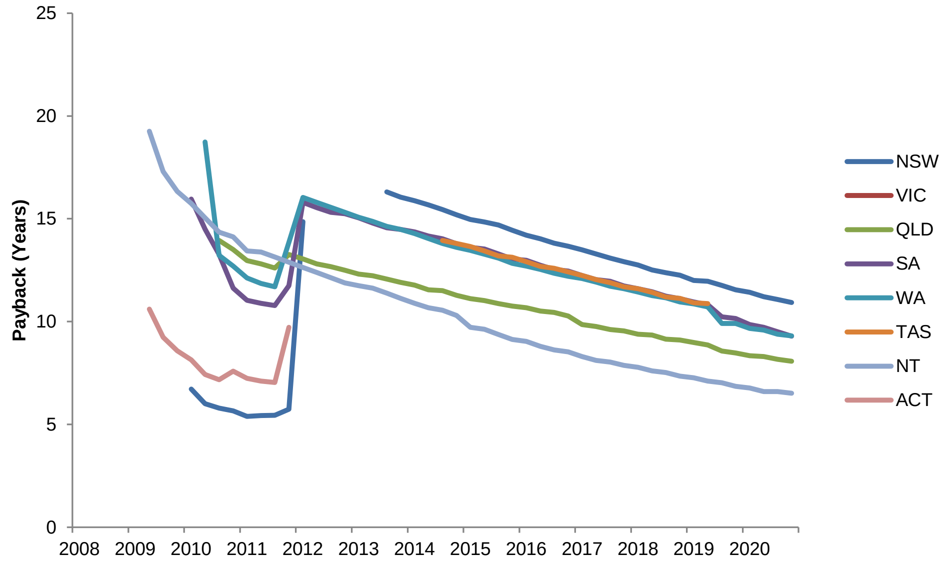
Figure 19 **Financial payback results: Counterfactual Scenario**



Note: Financial payback using a nominal discount rate of 10%

Data source: ACIL Tasman analysis

Figure 20 **Payback expressed in years: Counterfactual Scenario**

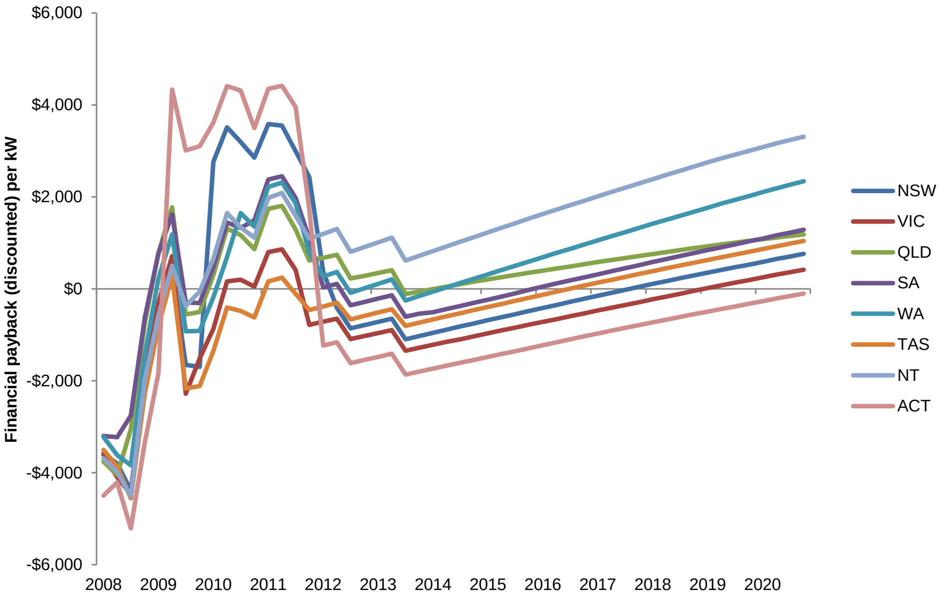


Note: Time required to recoup of-out-pocket costs (undiscounted). Breaks in the series indicate payback does not occur.

Data source: ACIL Tasman analysis

3.6.6 WA network sensitivity

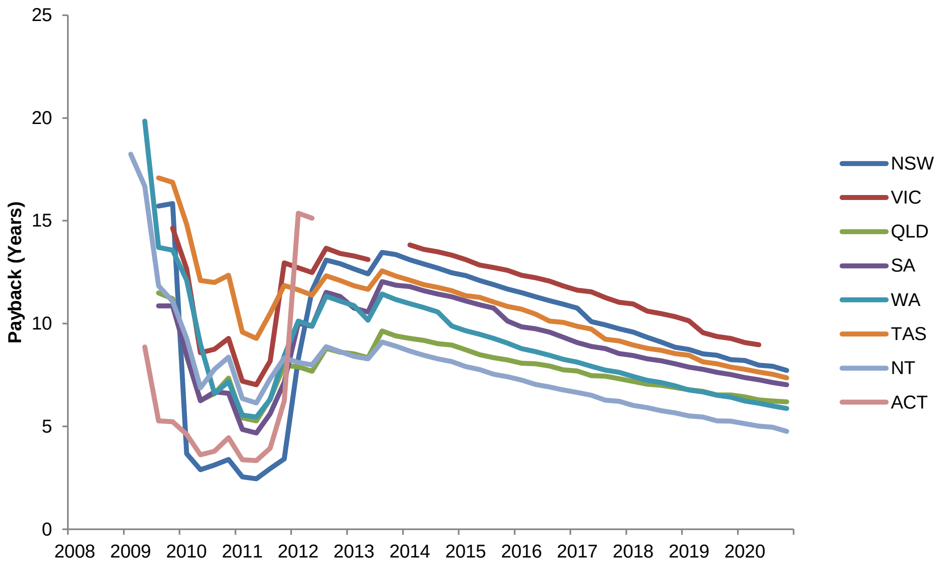
Figure 21 **Financial payback results: WA network sensitivity**



Note: Financial payback using a nominal discount rate of 10%

Data source: ACIL Tasman analysis

Figure 22 **Payback expressed in years: WA network sensitivity**



Note: Time required to recoup of-out-pocket costs (undiscounted). Breaks in the series indicate payback does not occur.

Data source: ACIL Tasman analysis

4 Econometric analysis

The econometric analysis attempts to establish a relationship between the calculated financial paybacks and historic PV capacity installed in the period 2008 to 2010. It implicitly assumes that households have undertaken a reasonably sophisticated financial evaluation of the costs and benefits of installation and have acted in a rational manner, but in practice captures the reasonable assumption that fundamental trends in actual (expected) financial returns can be sufficiently understood by consumers such that this trend can explain their likely behaviour.

ACIL Tasman has adopted a multiple regression approach in projecting take-up of new solar photovoltaic systems. The approach essentially fits a regression line through the existing historical data such that the sum of squared errors are minimised between the fitted or predicted values of the model and the actual observations. This model is then used to project future uptake in each jurisdiction based on the projected future financial paybacks available. In doing so, the model is able to account for changes in policy or other economic settings likely to occur in the future through its impact upon financial paybacks.

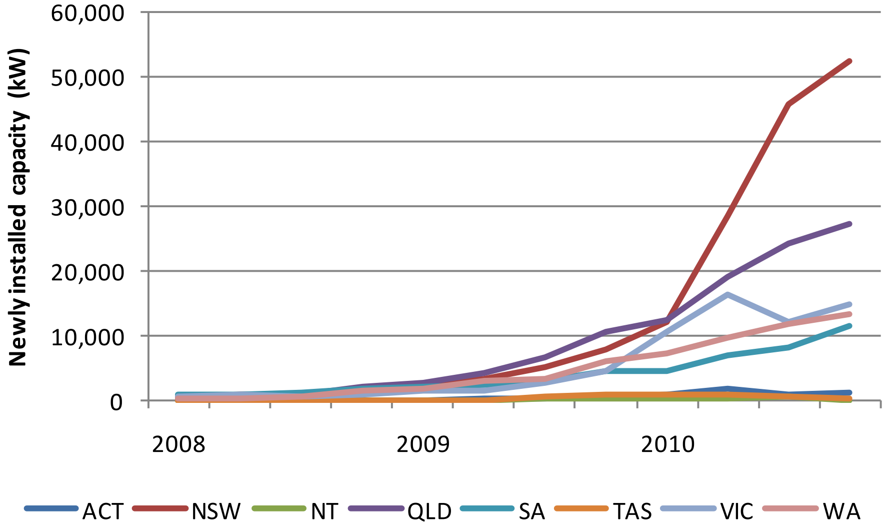
4.1 The data

The main data sets used in the modelling exercise are the quarterly take-up of new PV systems and the payback to the household from the various subsidies and feed-in tariffs arising as a result of the installation.

The PV system installation data was provided by ORER from its database of STC creation by SGUs. This data was current to March 2011, but as there is a lag between physical installation and STC creation, the data up until the end of 2010 was the primary focus of this analysis.

Figure 23 shows the increase in newly installed capacity from the first quarter of 2008 up to the end of 2010. It is evident from the figure that new installs have increased exponentially from about the start of 2009.

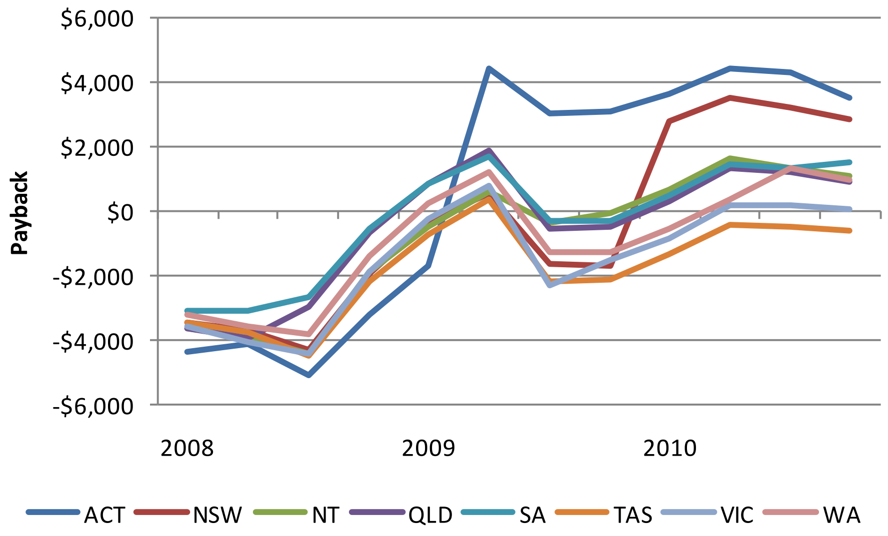
Figure 23 **Quarterly installation of new solar PV systems by State, 2008:1 to 2010:4, capacity (kW)**



Data source: ACIL Tasman based on ORER data

Figure 24 shows the payback to the household from the installation of a solar PV system over the same period. The figure shows that corresponding to the rapid take-up of new solar systems there has been a significant improvement in the payback from installation between 2008 and 2010, across all states but particularly in the ACT and NSW.

Figure 24 **Quarterly payback from installation by State, 2008:1 to 2010:4**



Data source: ACIL Tasman analysis

Our approach posits that the key driver of the take-up of new solar systems has been the significant improvement in the payback arising from increased government subsidies such as feed-in tariffs and Solar Credits.

4.2 Model specification

4.2.1 Identifying the key drivers of take-up

While the main driver of new installations is likely to be the economic payback from installation, it is possible that other drivers could potentially provide some explanatory power. For example, rising disposable incomes or an increase in environmental awareness of households could potentially play a role. In addition, the increased marketing of solar systems over the period is likely to have a positive impact on sales of solar PV systems over and above the increased economic benefits of installation.

ACIL Tasman empirically tested the explanatory power of disposable incomes into the model and found that rising incomes were not a statistically significant driver of installed capacity of solar systems over the historical period. While having sufficient disposable income available to be able to install a solar PV system is likely to be an important driver for a particular household, it does not constitute a suitable variable within the regression at a macro level.

The increase in environmental awareness or marketing of solar PV systems is likely to impact on the take-up of new solar PV systems in two ways. First, the responsiveness of the new installed capacity to improvements in the payback should increase. Second, the take-up of new systems will also increase independently of the payback. ACIL Tasman specified and tested a model which incorporated these features. Our results indicate that the responsiveness of new installations to the payback are greater in the period corresponding to the introduction of the Solar Credits scheme after the second quarter of 2009 compared to the period pre-dating its introduction. Also, a constant term which captures the level of installed capacity not associated with the payback variable was found to be significantly higher in the part of the sample corresponding to the Solar Credits scheme. This indicates that other factors such as increased awareness and marketing of solar systems have played a role in driving the uptake of new solar capacity.

4.2.2 Non-linear relationship between new installations and payback

A key aspect of the model specification is that it follows a non-linear functional form. ACIL Tasman was able to confirm empirically that an exponential function was able to best capture the relationship between the take-up of new solar PV capacity and the payback from installation. The estimated equation is shown below.

$$\text{Capacity installed} = \exp\left(c + \beta_1 \times \text{Payback}(1) + \beta_2 \times \text{Payback}(2) + \text{SC dummy}\right)$$

The new capacity installed in each quarter is modelled as an exponential function of the payback from installation, with the coefficients β_1 and β_2 corresponding to the degree of responsiveness in new capacity from a change in the payback before and after the introduction of the Solar Credits scheme respectively. The SC dummy picks up an upward shift in the constant term which occurs after the introduction of the Solar Credits scheme in the third quarter of 2009. This variable is effectively capturing the non-economic factors that are partially driving the increased uptake of new solar systems.

A separate regression was estimated for each of the states and territories in Australia. For the purposes of estimation, the model was transformed to linearity by taking the natural logarithm of both sides of the above equation.

The model utilises the weighted financial paybacks detailed in section 3.6. ACIL Tasman tested the use of financial paybacks for systems of different sizes within each jurisdiction but found the historical data to be somewhat 'thin' for certain categories. It was therefore decided that the weighted financial payback – whilst lacking some of the granularity desired – offered the optimal historical series for the regression.

4.3 Model results

The results from the estimated models are shown in Table 10 below. The fit of the models against historical data as measured by the R^2 statistic generally exceeded 85% for all jurisdictions suggesting that a significant proportion of the variation in the dependent variable is explained by the explanatory variables. The one exception was the Northern Territory where only 57% of the total variation in the natural logarithm of newly installed capacity could be explained by the explanatory variables.

Table 10 **Model coefficients, t statistics and R^2**

State	Constant	t-Stat	β_1	t-Stat	β_2	t-Stat	SC dummy	t-Stat	R^2
ACT	4.842	27.789	0.000000	NS	0.000512	7.721	0.000	NS	0.86
NSW	7.916	28.940	0.000294	3.037	0.000326	4.216	1.390	4.027	0.94
NT	4.264	15.518	0.000000	NS	0.000309	2.189	1.071	2.250	0.57
QLD	7.725	48.590	0.000354	5.906	0.000583	3.250	1.619	7.214	0.96
SA	7.530	78.725	0.000201	4.710	0.000506	4.767	0.794	5.405	0.96
TAS	4.768	17.808	0.000000	NS	0.000197	2.222	1.968	7.629	0.91
VIC	7.221	51.070	0.000199	4.155	0.000656	6.600	2.297	12.548	0.98
WA	7.513	37.308	0.000376	4.870	0.000402	2.756	1.477	5.877	0.94

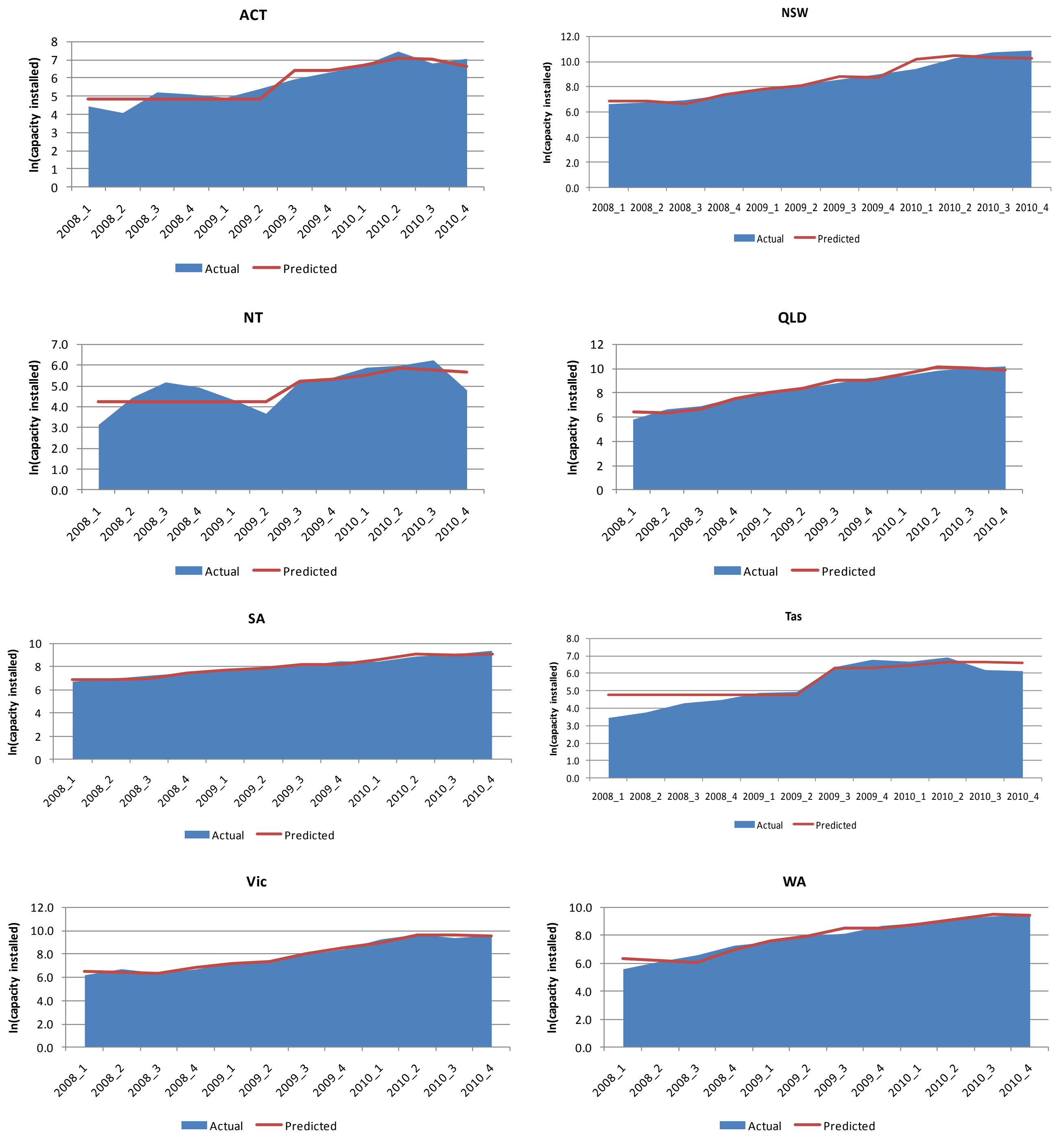
Data source: ACIL Tasman model

All estimated coefficients were found to be statistically significant at the 5% significance level, apart from those denoted as NS for the ACT, NT and

Tasmania. In this case the insignificant variables were removed from regression and the model re-estimated.

A graphical representation of the models in sample predictive power is shown in Figure 25.

Figure 25 **Model predicted versus actual values, natural logarithm of capacity installed (kW)**



Data source: ACIL Tasman model

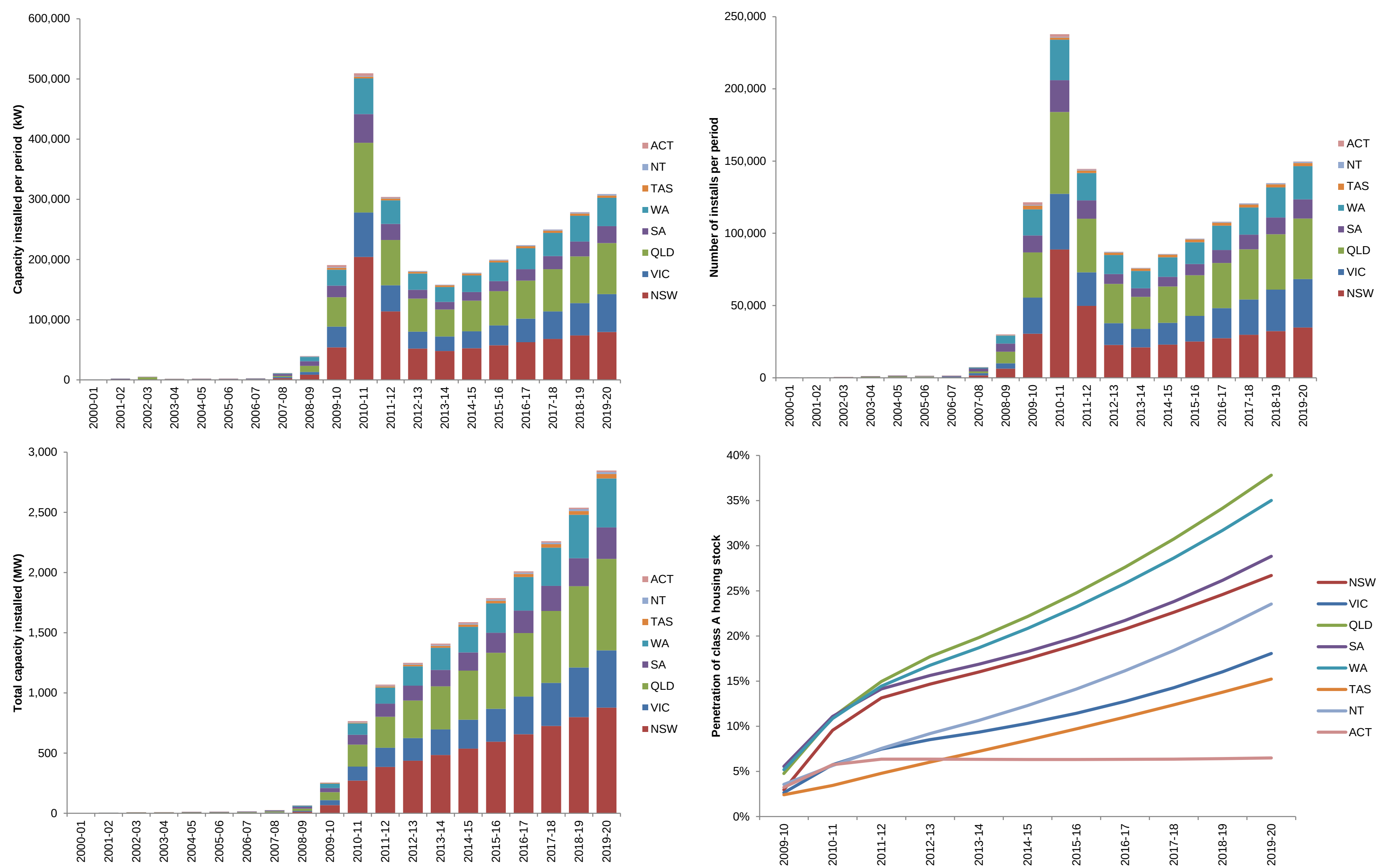
4.4 Projected solar PV installations

The model coefficients allow the projection of future PV capacity installed in each jurisdiction based on the future financial paybacks presented in section 3.6. Paybacks were calculated on a quarterly basis and allow the projection to provide quarterly capacity installed.

Figure 26 shows the projection results for the Core Scenario:

- The chart on the top left shows projected installations each financial year. Installations drop from a peak of around 500 MW in 2010-11 to around 300 MW in 2011-12 and 180 MW in 2012-13 – primarily a result of the Solar Credits multiplier reduction and parallel reductions in various feed-in tariffs. Annual capacity installed grows slowly each year thereafter, reaching annual installations of around 300 MW again by the end of the projection period.
- The chart on the bottom left shows cumulative installed PV capacity in each jurisdiction. By the end of 2019-20 a total of 2,848 MW is projected. National shares include NSW with 31% (878 MW); Queensland 27% (761 MW); Victoria 17% (475 MW); Western Australia 14% (407 MW) and South Australia 9% (261 MW). Other jurisdictions account for a relatively small proportion with aggregate capacity of 66 MW.
- The chart on the top right shows the number of installations per financial year. Installations follow a similar pattern to capacity, with the peak occurring in 2010-11 with around 240,000 installations. This falls to as low as 76,000 in 2013-14, before recovering to around 150,000 by the end of the projection. In total, the model projects around 1.4 million PV installations will have occurred by 2020. This represents around 1 million additional installations above the current level of approximately 400,000.
- The bottom right chart shows the level of solar PV penetration in owner-occupied class A dwellings (detached or semi-detached dwellings), on the basis that this household type is most likely to install such systems. By 2020, Queensland and Western Australia are projected to have the highest penetration with over 35% of eligible houses having solar PV installed. The ACT has the lowest penetration level at less than 7%, with limited installations occurring once the gross FiT reaches its cap, due in large part to very low retail electricity tariffs in that jurisdiction.

Figure 26 **Projected capacity, installations and household penetration by jurisdiction: Core Scenario**



Note: Actual installations to 31 December 2010.

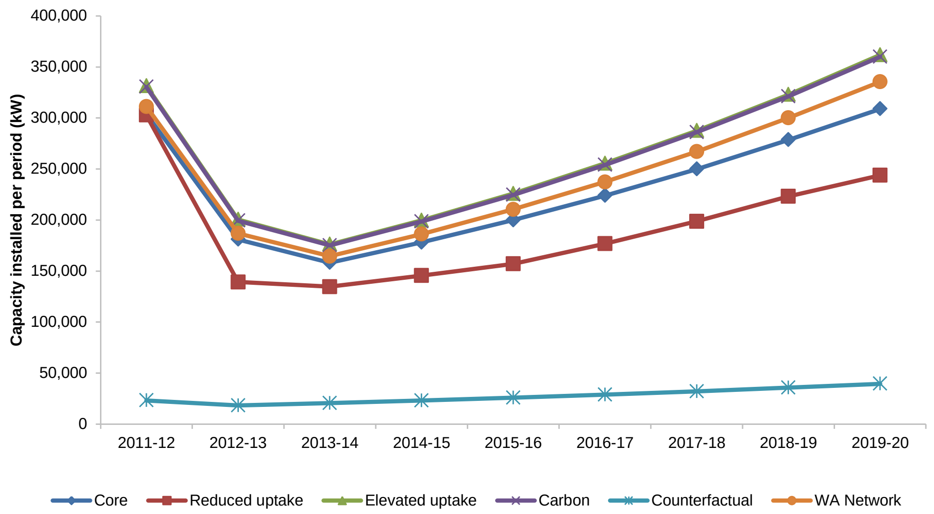
Data source: ACIL Tasman analysis

4.4.1 Scenario results

Figure 27 shows the capacity installed each financial year under all of the scenarios. The Core, Elevated Uptake, Carbon and WA Network scenarios all exhibit similar installation rates throughout. The Reduced Uptake Scenario sees lower installation rates as a result of the faster Solar Credits multiplier reduction, coupled with a decrease in the STC price and lower FiT rates/caps in some jurisdictions.

The Counterfactual Scenario involved the removal of the SC Dummy variable within the regression – essentially simulating a world where the solar PV industry did not transition from a small-scale 'cottage' industry. The results from this scenario are significantly lower than any of the other scenarios with annual installations of less than 50 MW throughout.

Figure 27 **Aggregate capacity installed per period: All scenarios**

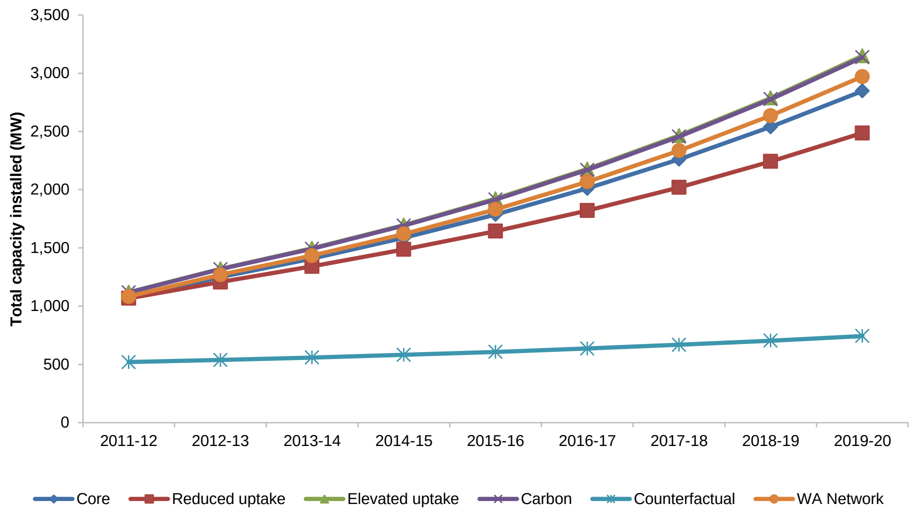


Data source: ACIL Tasman analysis

Figure 28 shows cumulative PV capacity across each of the scenarios. Total PV capacity installed by the end of the projection is:

- Core Scenario: 2,848 MW
- Elevated Uptake Scenario: 3,149 MW
- Reduced Uptake Scenario: 2,487 MW
- Carbon Scenario: 3,137 MW
- Counterfactual Scenario: 744 MW
- WA network sensitivity: 2,971 MW.

Figure 28 **Cumulative PV capacity: All scenarios**



Data source: ACIL Tasman analysis

It should be noted that the projections of PV uptake are quite conservative, particularly for the period April to June 2011. Observed installation rates in the lead up to the reduction in the Solar Credits multiplier on 1 July 2011 suggest a significant surge in installations seeking to receive the multiplier of five.

Further, ongoing strong installation rates have been observed during the second half of 2011, reflecting that the rate of reduction in PV system costs in recent months is greater than that assumed in our April 2011 system cost projection.

The events of the period April to June 2011 indicate that an alternative functional form for the econometric model used in this analysis could potentially offer greater explanatory power in dealing with sudden policy changes of the kind observed during 2011. It is likely that consumers respond not only to the financial return available from committing to a PV installation in the present, but also to anticipated reductions (or increases) to this return in the immediate future. For any given level of absolute financial return, installation rates are likely to be higher if financial returns are anticipated to reduce in future, for example due to the closure of a feed-in tariff or reduction in the Solar Credits multiplier. Conversely, if financial returns are expected to stay broadly constant or improve, a lower level of present day installation could be expected as consumers are more 'patient' in committing to installations.

Notwithstanding this, the materiality of the changes to PV policy settings are unprecedented in the data set available for this exercise, and so it is likely that calibrating an econometric model to accurately predict the extreme surge in installation rates during April to June 2011 would be challenging.

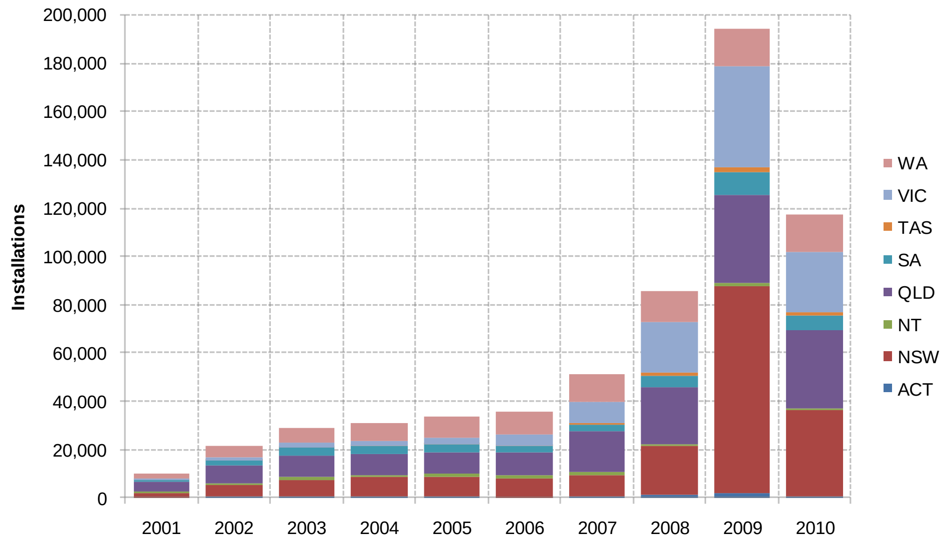
Nevertheless, as feed-in tariffs phase out and the financial return to PV systems becomes more strongly driven by reducing system costs and higher electricity prices, rather than STC and feed-in tariff subsidies, the scope for substantial reductions in financial returns over the longer projection period is more limited. Accordingly, the state and national level projections to 2020 remain useful in outlining the aggregate cost and emissions trends arising from the SRES policy, particularly in the context of reducing PV system costs and rising electricity prices.

5 Solar water heater projections

SWHs are a relatively mature technology and have been part of the technology suite for water heating for decades in Australia. Subsidies are provided via upfront rebates (at State or Federal level) and are eligible for RECs/STCs.

Figure 29 provides an overview of the number of SWH installations that have occurred by jurisdiction since 2001.[6] In the early part of the decade installations were growing steadily, reaching 50,000 through calendar year 2007. Recent years have seen a significant increase in installation rates – particularly in 2009 – where installations were occurring on an opportunistic basis rather than simply as stock replacement.

Figure 29 **SWH installations by jurisdiction by year**



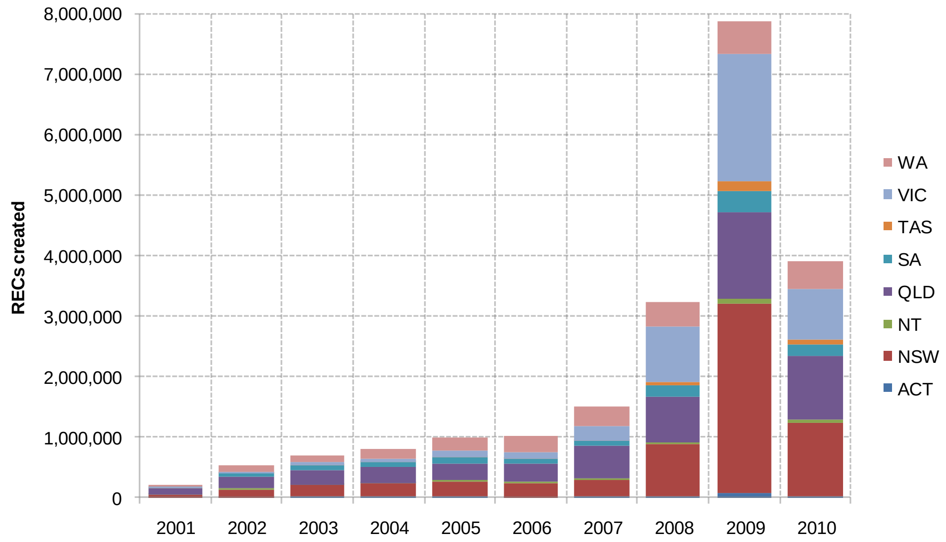
Note: Data current to 17 March 2011, therefore data for calendar year 2010 may not be complete.
Data source: ACIL Tasman analysis based on ORER Registry data

SWH installations create RECs/STCs through deeming. A certificate is equivalent to 1 MWh of electricity deemed to be displaced by the installation of the solar water heater. Certificates are able to created upon the installation of the system based on a maximum deeming period of 10 years.

Figure 30 shows the corresponding RECs created since 2001. Certificate creation has followed installs reasonably closely, with the peak creation of around 8 million certificates in 2009.

[6] Note that this data is derived from ORER REC registry data and therefore additional installations may have occurred which did not apply for RECs that will not be picked up by this data.

Figure 30 **RECs created from SWH by jurisdiction by year**



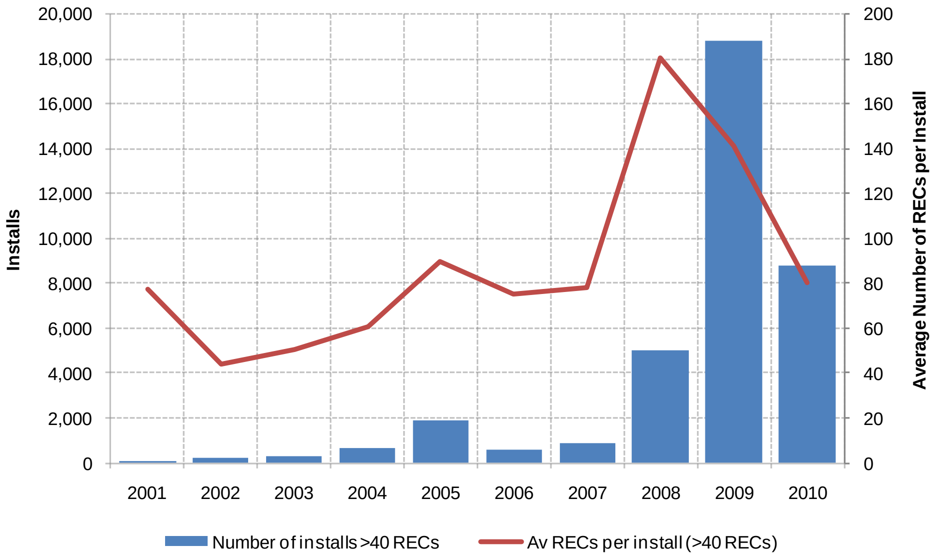
Note: Data current to 17 March 2011, therefore data for calendar year 2010 may not be complete.
Data source: ACIL Tasman analysis based on ORER Registry data

One explanation for the surge in installations and RECs created from mid 2008 was the number of larger SWH systems being installed. Figure 31 shows the number of installations that were eligible for more than 40 RECs (larger systems including commercial installations) and the average number of RECs created per install. The number of larger installations surged during 2008 and 2009, driven by rebates and certificate value.

Part of the driver for this surge was the large uptake of commercial scale air source Heat Pump Water Heaters (HPWHs) which were being installed on a purely commercial basis rather than replacing existing hot water systems that had reached the end of their useful life. In some cases the installations were of a size that far exceeded the requirement for hot water at the premises and driven purely by the commercial incentives the subsidies provided.

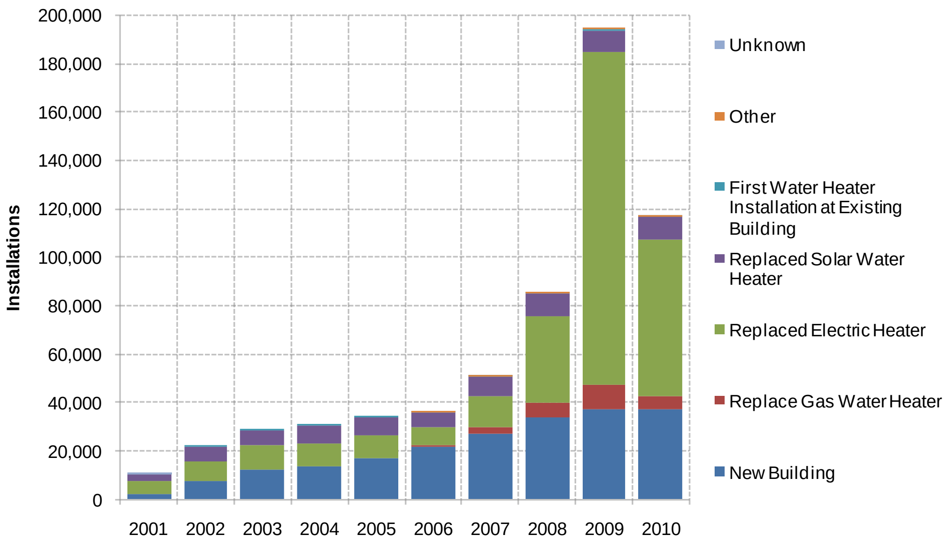
With the changes to regulations introduced in June 2010 which effectively excludes commercial-scale heat-pump systems (greater than 425 litres in capacity) from creating RECs/STCs, installations of this type have fallen dramatically. Traditional hot water systems above 700 litres now also have to be accompanied by statutory declarations which confirm the appropriate size of the installation. This may also prompt a reduction in installations.

Figure 31 **Installs and average RECs created from larger installations**



Note: Data current to 17 March 2011, therefore data for calendar year 2010 may not be complete.
Data source: ACIL Tasman analysis based on ORER Registry data

Figure 32 **SWH installation type**



Note: Data current to 17 March 2011, therefore data for calendar year 2010 may not be complete.
Data source: ACIL Tasman analysis based on ORER Registry data

Figure 32 shows SWH installations by type. Historically, around half of the installations were associated with new building developments – in part driven by new building standards – however, in the last few years replacement of existing electric hot water has gained in importance. Aside from the oversized commercial installation issue described previously, the increase in electric replacements has been a result of government regulations that limit the circumstances under which certain water heating technologies (particularly electric water heating) can be used.

5.1 Projection methodology

ACIL Tasman's projection of STC creation by SWHs was developed through use of a water heater stock model, which was used to analyse:

- The changing size and technology composition of the (residential) water heater stock from 1980 to 2020
- Historic rates of substitution between water heater technologies on a 'technology pair' basis, e.g. solar for electric, gas for electric, solar for gas etc.
- Historic technology shares in the new building water heater market
- The overall effect of these trends on SWH installation and STC creation rates over the period 2011 to 2020.

The methodology chosen was not primarily cost-based for a range of reasons (although changes in rebates and STC subsidy levels were taken into account). These reasons include:

- Substitution to SWHs from other water heating technologies varies significantly depending on the technology being substituted away from. For example, electric to solar switching is far more prevalent than gas to solar switching, likely due to the relatively low running costs of gas water heaters and high once-off costs of gas reticulation connections. Accordingly, the composition of the total water heater stock at a point in time is arguably more relevant for determining its future change than the relative cost of technologies at any single point in time. Further, the composition of the stock reflects the relative cost of various technologies over the preceding 10-25 years (as the stock evolves and is gradually replaced), implicitly capturing the relative economic merits of these technologies indirectly.
- A range of non-cost based regulatory measures affect water heater technology choice, not least the effective banning of electric water heaters in most Australian jurisdictions for certain classes of dwelling (broadly, detached and semi-detached dwellings) in certain locations (generally in locations where reticulated natural gas is available). As the effect of these regulations varies according to location and dwelling type, a pure cost-based analysis would not capture their effect correctly. Rather, the composition of the housing market and availability of reticulated natural gas must be analysed to project their impact robustly.
- A cost-based analysis is complicated by the range of technology types available in the water heater market, which include:
  - Electric storage (which in turn could use regularly metered electricity or cheaper 'off-peak' metered electricity)

  - Mains gas storage
  - Mains gas instantaneous
  - Liquefied petroleum gas (LPG) storage or instantaneous
  - Solar (including heat pump and flat plate technologies, and electric or gas boosting)
  - Miscellaneous other technologies, including wood heaters.
- The economic value of a water heater type will vary radically from household to household depending on consumption patterns. A larger household (in terms of occupants) with greater hot water usage will enjoy greater economic benefits from the higher capital cost, lower running cost SWHs than a smaller household. Unlike the situation for solar PV, where excess solar energy can be fed into the grid and earn an economic return, excess solar heated water (considered on a 24 hour cycle) does not have a ready use and will not deliver any economic benefit to the household.

A further implication of the stock model based approach is that the effect of carbon pricing or related policies on electricity and gas prices has not been directly taken into account. Rather, the range of possible variation due to other drivers, including fuel and technology costs, subsumes this source of variation. Therefore, the scenarios analysed are independent of carbon pricing and other policy effects, and therefore can be considered independent of the solar PV system scenarios analysed above.

The approach we have adopted for the overall STC creation estimate is to combine our Reference SWH STC projection with every solar PV system STC projection to derive the overall STC projection. However, we have also developed High and Low scenarios for analysis of the sensitivity of the overall projection to SWH outcomes. We have also undertaken a Counterfactual Scenario for the purpose of estimating abatement from SWHs under each scenario.

In summary, the four SWH scenarios analysed were:

- Reference
- High SWH uptake
- Low SWH uptake
- Counterfactual.

It is also important to note that the stock model approach adopted was primarily residential in focus. The primary reason for this is that a legislative change in June 2010 prevented further REC/STC creation from air source HPWHs of greater than 425 litres in capacity, effectively excluding commercial-scale heat-pump systems that were creating large numbers of RECs under earlier arrangements.

Whilst some commercial enterprises will continue to install smaller air source HPWHs, or conventional flat plate type SWHs, this regulatory change has effectively removed commercial trends as a key independent driver of SWH uptake. Rather, given the greater size of, and extensive data available on, the residential housing stock, we deemed the most robust methodology to be a residential focused stock model where commercial installation trends are attributed to that sector and implicitly assumed to move with residential trends.

To control for the June 2010 policy change, this projection focuses exclusively on installations that create less than 60 RECs, which are effectively household-scale SWHs (including small HPWHs), when analysing the historical data set.

5.2 Stock model structure

A key component of the water heater stock model was developing a comprehensive picture of the current residential housing stock and the prevalence of different water heater types within that stock.

As the key issue for the purposes of this projection is to estimate the rate at which water heaters of a particular type are replaced, we considered it necessary to build a picture of the residential water heater stock from 1980, thereby picking up the (lagged) effect of past installation trends on future replacement rates by technology.

At its heart, this stock model required analysis of both the housing stock (to estimate the total size of the water heater stock employed in the residential sector) and the technological composition of that water heater stock.

5.2.1 Housing stock

The overall housing stock in each state over the period 1980 to 2006 was compiled by reference to the Australian Bureau of Statistics (ABS) 2006 census date and quarterly dwelling completion data preceding the census date.

The change in the housing stock was assumed to be equal to the ABS completion rate for each quarter, less an assumed house demolition rate of 0.05% of the total stock per quarter (held constant over the entire analysis). This rate was the quarterly equivalent of the annual rate assumed by the then Commonwealth Department of Environment, Water, Heritage and the Arts (DEWHA) in its 2008 study.[7]

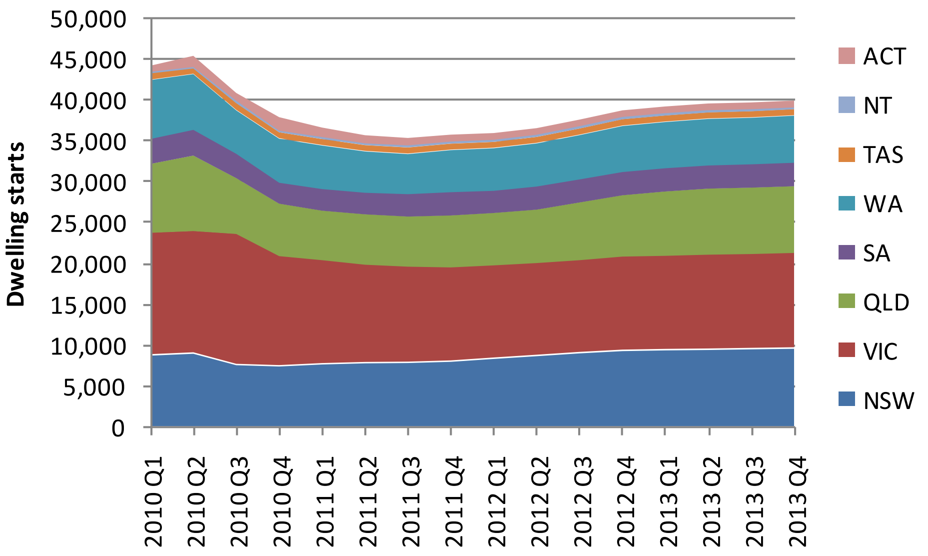
The total housing stock was then projected from 2006 to 2010 and beyond using a combination of ABS quarterly dwelling completion data and Housing

[7] DEWHA, 2008, *Energy Use in the Australian Residential Sector 1986-2020* (page 18).

Industry Association of Australia (HIA) estimates of dwelling starts to the end of 2013.

HIA dwelling starts were lagged by three quarters to estimate a housing completions number. The original HIA data is presented in Figure 33.

Figure 33 **Projected housing starts**

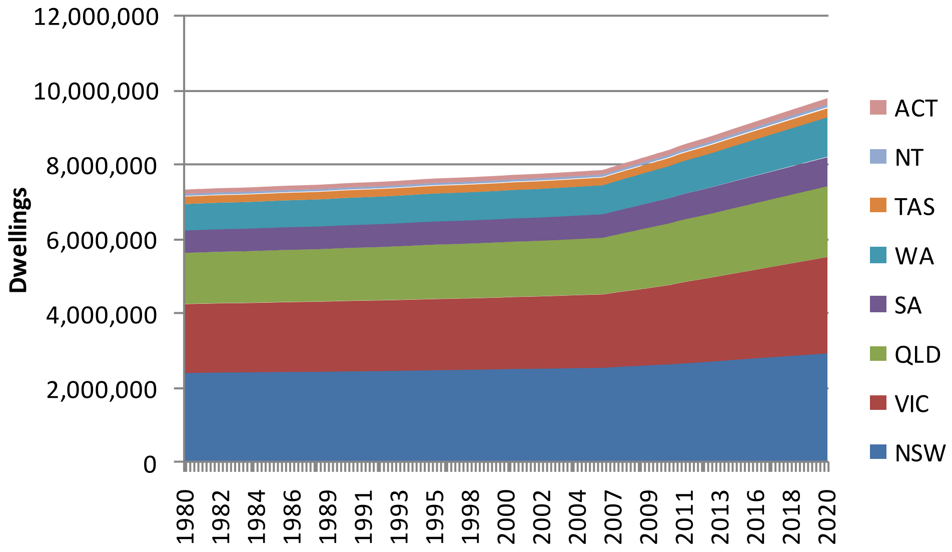


Data source: Housing Industry Association of Australia Economics Group, March 2011 forecast (published April 2011).

Dwelling completion rates were extrapolated to 2020 as the simple average of the HIA's estimated dwelling starts over 2010-2013 in each state.

The total residential dwelling stock over the period 1980-2020 is shown below in Figure 34.

Figure 34 **Residential dwelling stock by jurisdiction**



Source: ACIL Tasman projection using ABS data and HIA analysis.

The composition of the residential dwelling stock in terms of dwelling type (separate house, semi-detached, flat/apartment or other) and ownership type was projected from 2006 to 2020 by reference to 2006 compositional data. Specifically, the number of separate houses and semi-detached dwellings as a share of new dwellings was assumed to be the same as their share of the 2006 total housing stock for each jurisdiction. Similarly, the share of rented and owner-occupied dwellings was held constant (looking at the stock as a whole) over the period 2006 to 2020.

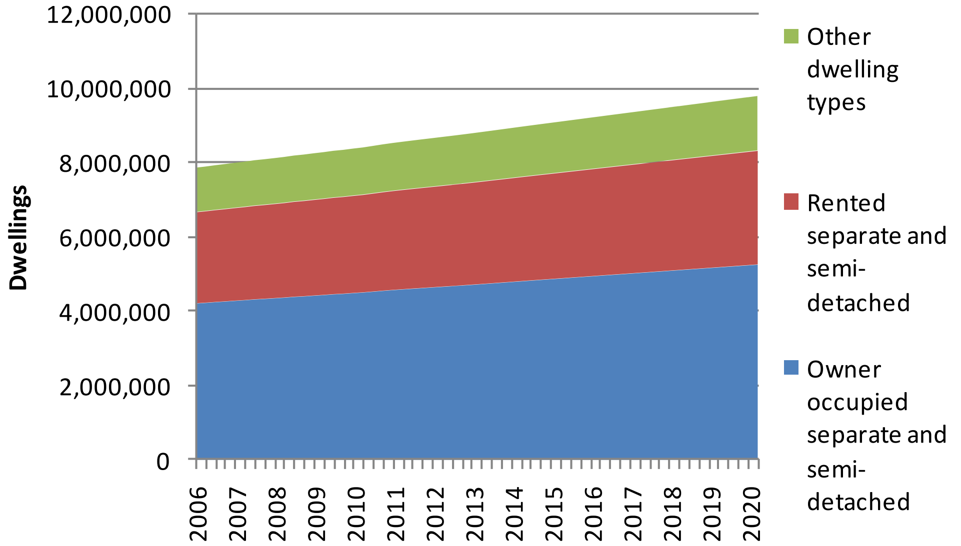
Analysis of 1996 and 2001 census data reveals that trends in ownership and dwelling structure have been highly stable over time with, if anything, a trend towards separate and semi-detached dwellings (notwithstanding 'densification' of major urban centres) and higher owner-occupancy rates (notwithstanding home affordability issues and strong rates of investment in rental properties). Accordingly, an assumption of holding these trends constant over time appears robust for these purposes.

For simplification, the rate of SWH penetration in flats and apartments is assumed to be zero in this analysis. Accordingly, trends in SWH take up can be projected purely through reference to three dwelling types:

- Owner-occupied separate houses and semi-detached dwellings
- Rented separate houses and semi-detached dwellings
- Flats, apartments and other dwelling types (irrespective of ownership).

The share of these three broad dwelling types in the Australian housing stock is shown in Figure 35.

Figure 35 **Residential dwelling stock by dwelling type and ownership**



Source: ACIL Tasman assumptions based on ABS data.

5.2.2 Water heater stock

As noted above, the key issue for the purposes of this projection is to estimate the rate at which water heaters of a particular type are replaced. Accordingly, we considered it necessary to build a picture of the residential water heater stock from 1980 to pick up the (lagged) effect of past installation trends on future replacement rates by technology (in effect, the rate of installation of a given technology in the 1990s and 2000s will impact the number of systems using a given technology that will be replaced during the projection period)

The primary data source for this was the comprehensive 2008 study by DEWHA, *Energy Use in the Australian Residential Sector 1986-2020* ('the DEWHA study'). It analysed historical data and projected water heater technology shares by jurisdiction over the period 1966 to 2020 (Tables 132 to 138), allowing separation of water heaters into the following categories:

- Electric
- Mains gas
- LPG
- Solar
- Other.

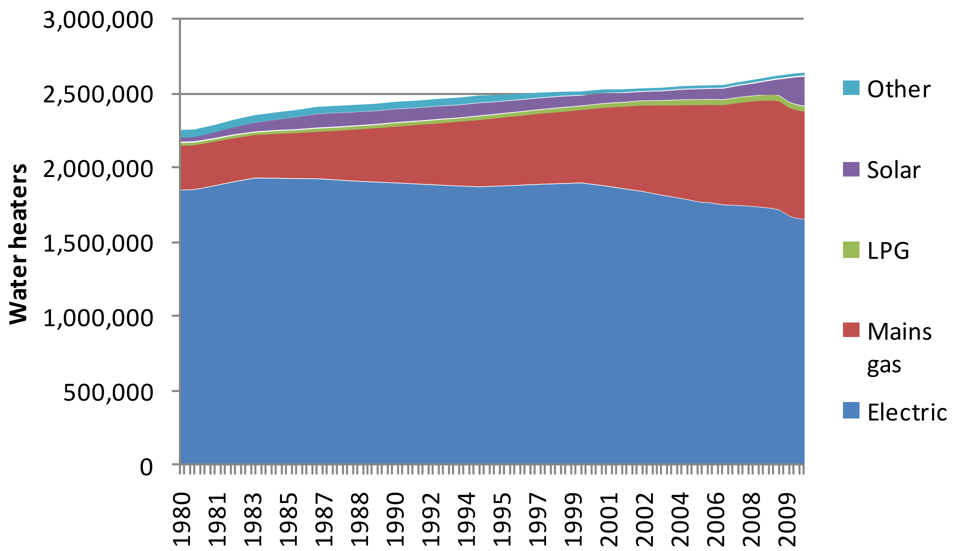
DEWHA also estimated the share of households with no water heater. ACIL Tasman incorporated this estimate into the historic data set, noting that this rate fell to zero in all jurisdictions by 1994.

The DEWHA data was adopted unadjusted to 2006 to develop a picture of the water heater stock in 2006.

The changing shares of technologies in key states, within the overall state level housing stock estimated by ACIL Tasman, are shown in Figure 36 to Figure 40 below.

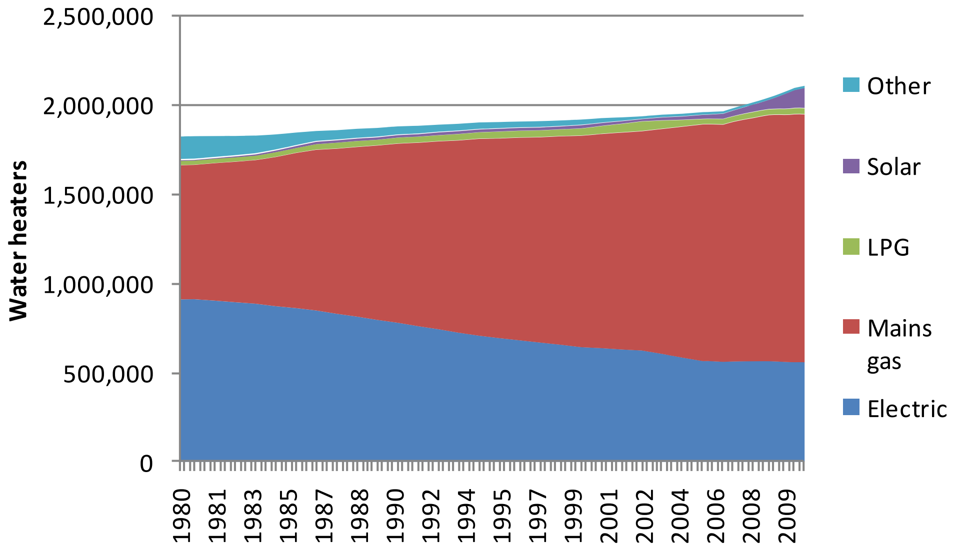
From 2006, ORER data on SWH installations was overlaid and used to adjust DEWHA SWH share estimates where appropriate. From 2011 onwards DEWHA data was not used directly, but historic trends from the DEWHA data were used to inform ACIL Tasman assumptions about electric to gas and other substitution pairs not involving SWHs.

Figure 36 **NSW water heater stock, 1980 to 2010**



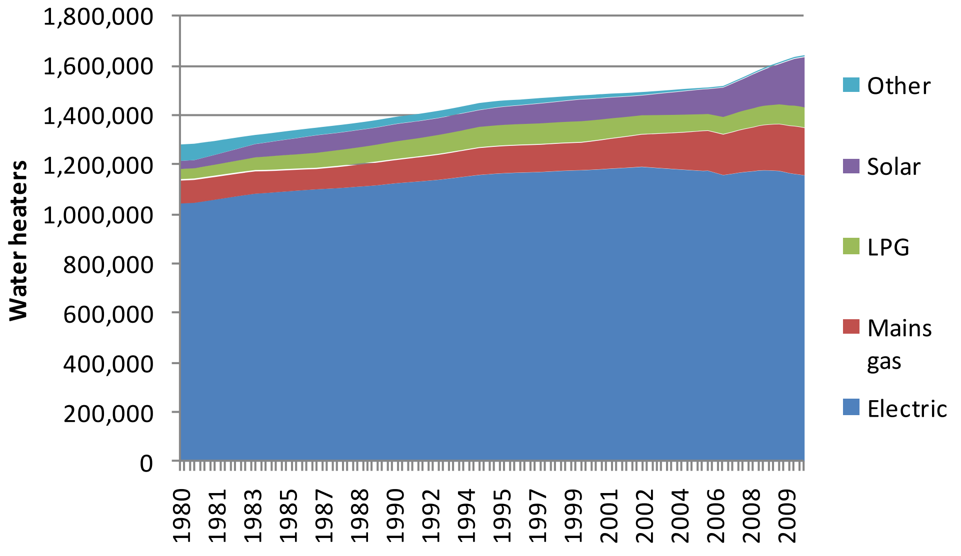
Data source: DEWHA technology shares; ORER SWH installations; ACIL Tasman total water heater stock based on ABS data and DEWHA estimates of households with no water heater.

Figure 37 **Victorian water heater stock, 1980 to 2010**



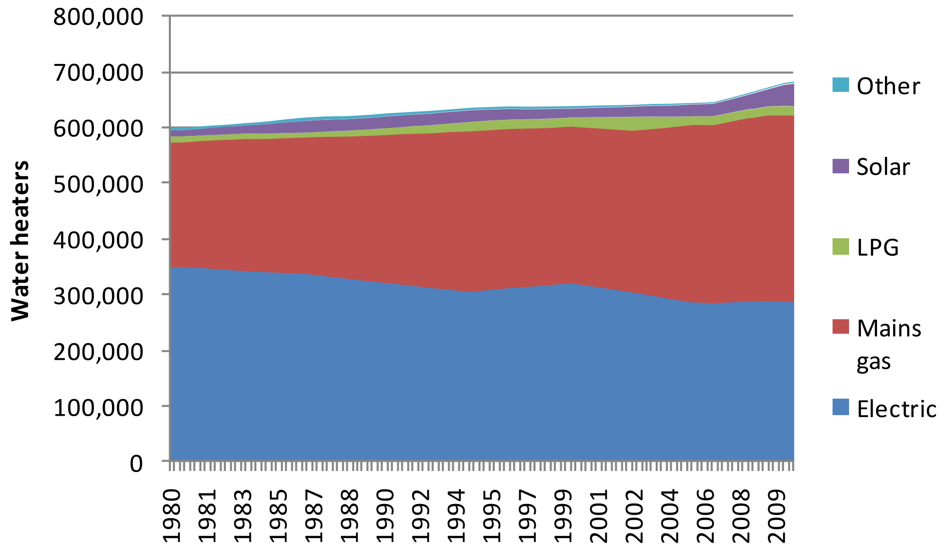
Data source: DEWHA technology shares; ORER SWH installations; ACIL Tasman total water heater stock based on ABS data and DEWHA estimates of households with no water heater.

Figure 38 **Queensland water heater stock, 1980 to 2010**



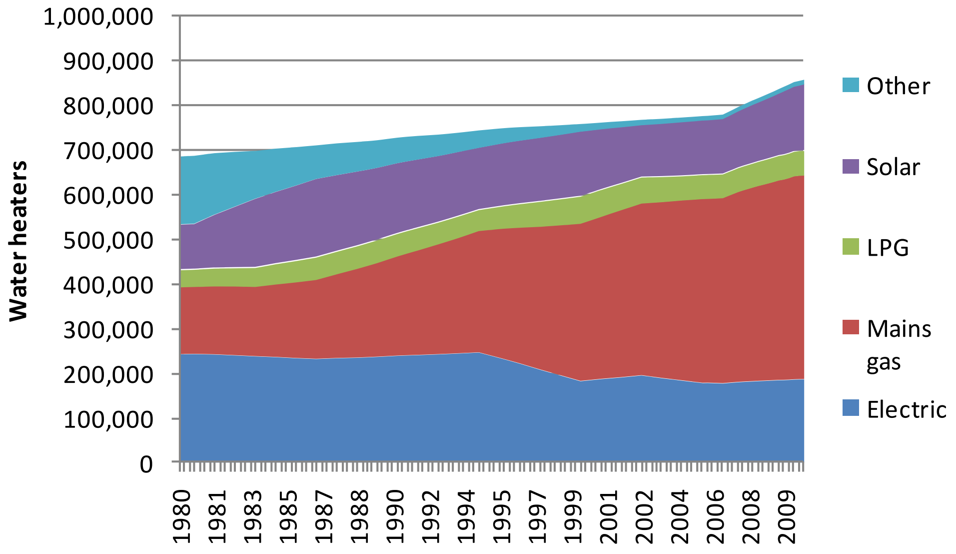
Data source: DEWHA technology shares; ORER SWH installations; ACIL Tasman total water heater stock based on ABS data and DEWHA estimates of households with no water heater.

Figure 39 **South Australian water heater stock, 1980 to 2010**



Data source: DEWHA technology shares; ORER SWH installations; ACIL Tasman total water heater stock based on ABS data and DEWHA estimates of households with no water heater.

Figure 40 **Western Australian water heater stock, 1980 to 2010**



Data source: DEWHA technology shares; ORER SWH installations; ACIL Tasman total water heater stock based on ABS data and DEWHA estimates of households with no water heater.

5.3 Relevant government policies

Governments around Australia provide support to the take-up of SWHs in various forms, including:

- Regulations that limit the circumstances under which competing water heating technologies (particularly electric water heating) can be used

- RECs/STCs
- Up-front rebates.

These regulatory and financial incentives feed into the projection assumptions used to calibrate the SWH stock model. Some key initiatives are outlined below.

5.3.1 Regulatory issues

In July 2009 the Council of Australian Governments agreed to phase-out the use of electric resistance water heaters as part of the National Partnership Agreement on Energy Efficiency. Implementation of this measure has been progressed by the Ministerial Council on Energy under the broader National Framework for Energy Efficiency.

Implementation of this agreement varies between jurisdictions but broadly involves the banning of the use of electric resistance water heaters in new-build detached or semi-detached dwellings where natural gas is available from 1 January 2010.

The state of play at the time of writing is broadly as follows:

- Western Australia has not implemented any new regulatory changes as it had already imposed equivalent standards on water heaters for new buildings from 1 September 2008
- New South Wales and Victoria have incorporated changes within their respective building codes effectively banning electric water heaters in new buildings from 1 January 2010
- Queensland and South Australia have made additional changes to their respective building codes, such that the effective ban applies to electric water heaters in new buildings and to replacement water heaters in 'class 1' dwellings (i.e. detached or semi-detached dwellings) where reticulated natural gas is available
- Tasmania is not implementing any changes due to the low greenhouse gas emissions intensity of its local electricity supply.

5.3.2 RET/SRES

As for solar PV systems, the RET has provided, and the SRES will continue to provide, up-front assistance to purchasers of SWHs by allowing them to create RECs or STCs which can be on-sold to recoup some of the cost of purchasing the system. SWHs are not able to create Solar Credits.

These certificates have value because the legislation underpinning the RET/SRES requires wholesale purchasers of electricity to purchase and acquit a certain number of certificates or pay a penalty.

The value of assistance varies with the value of a certificate. Whilst the value of a REC is set by the market for these certificates, the Government has effectively fixed the price of STCs by allowing liable entities to purchase them from a Government-run clearing house at a price of $40 (although STCs will be able to be traded outside the clearing house, and these prices may vary).

As for solar PV systems, RECs/STCs can be deemed over the life of a SWH and created in advance, rather than being created in an ongoing manner.

As discussed previously, a key recent change to the treatment of SWHs under the RET/SRES was the legislated change in June 2010 preventing air source HPWHs of greater than 425 litres in capacity from creating RECs/STCs.

5.3.3 Commonwealth Solar Hot Water Rebate

The Commonwealth Government provides direct assistance to SWHs through the value its Solar Hot Water Rebate (SHWR). The SHWR has undergone several changes in recent times, particularly:

- In September 2009, the HPWH rebate was reduced from $1600 to $1000
- In February 2010 the rebate for HPWHs was further reduced to $600
- In February 2010 the rebate for non-HPWHs was reduced from $1600 to $1000.

The SHWR is not means-tested, but is only available where the unit is replacing an electric water heater and where the applicant did not receive assistance under the Commonwealth Government's Home Insulation Program.

5.3.4 State and territory government rebates

A range of state and territory government rebates are available to SWHs. The state and territory schemes are briefly summarised in the table below.

Table 11 **State/territory SWH incentives and rebates**

Jurisdiction	Rebate	Date available	Conditions
NSW	$300	15 January 2010 to 30 June 2011	Replace electric hot water system
	$1500	Prior to 15 January 2010	As part of NSW Home Saver Rebate package
Queensland	$600	Since 13 April 2010	Replace electric hot water system
	$1000	Since 13 April 2010	For pensioners and low-income earners
Victoria	$300-$1600	-	Rebate depends on system size and varies between Melbourne and regional Victoria.

Jurisdiction	Rebate	Date available	Conditions
	Variable	Since 1 January 2009	Assistance through Victorian Energy Efficiency Certificates
Western Australia	$500-700	Until 30 June 2013	Applies only to gas or LPG boosted solar systems
South Australia	$500	Since 1 July 2008	System must replace electric hot water system or be gas-boosted
Tasmania	N/A	-	-
Northern Territory	Up to $1000	-	Timber-trussed roofs that require reinforcement
	Up to $400	-	Where additional plumbing is required
Australian Capital Territory	Up to $500	-	Must replace an electric hot water system and be used in conjunction with other energy saving investments.

Data source: www.energymatters.com.au; www.environment.nsw.gov.au; www.cleanenergy.qld.gov.au; www.resourcesmart.vic.gov.au; www1.home.energy.wa.gov.au; www.dtei.sa.gov.au; www.powerwater.com.au.

5.4 Projection assumptions

Having developed a picture of the water heater stock at the start of the STC projection period (1 January 2011), the projection methodology adopted from this point estimates the rate of SWH installations in new buildings and the rate for those replacing existing water heaters in existing buildings separately.

There are several reasons for this:

- The total rate of each type of installation are significantly different in volume (with substantially greater replacement installations than new building installations).
- The total volume of each type of installation are driven by different factors, with new building installations being driven by dwelling completions and replacement installations being driven by the rate of turnover of the existing stock due to failure and, to a lesser extent, economic replacement decisions.
- The type of water heater being replaced significantly affects the penetration rate of SWHs in replacement installations, requiring analysis on the basis of 'technology pairs'. By contrast, this dynamic is not present in the new building market.
- The application of regulatory restrictions on electric water heaters vary between new buildings and replacement water heater installations.
- Several state level rebates only apply to replacements for electric water heaters (i.e. they do not apply to installations in new buildings).
- The lag rate between SWH installation and STC creation is materially different between new building and replacement installations (with new

building installations being significantly slower to move to STC creation than replacement installations).

5.4.1 New building SWH penetration

SWH penetration rates in new buildings were projected through comparison with recent historic rates, and adjustment factors over time set to reflect the impact of regulations on the use of electric water heaters, and the effect of increasing penetration of reticulated natural gas. The overall assumptions are presented in Table 12.

Table 12 **Comparison of historic new build and projected SWH penetration levels**

	Historic				Projected			
Jurisdiction	2008	2009	2010 (Q1-Q3)	2008-Q3 2010 avg	Reference	High	Low	Counter factual
NSW	17.5%	16.3%	18.1%	17.2%	20-30%	25-40%	20%	8%
Victoria	38.1%	45%	48%	43.4%	45%	45-50%	40-30%	8%
Queensland	36.7%	38.4%	39.8%	38.1%	40-35%	45%	40-30%	10-15%
South Australia	10.3%	11.1%	13.4%	11.5%	15-25%	20-30%	20-15%	8%
Western Australia	19.5%	21.8%	28.4%	22.8%	25-30%	30-45%	25%	20%
Tasmania	6.5%	6.7%	8.7%	7.1%	7.5%	10-15%	5%	2%
Northern Territory	80.9%	33.5%	59.6%	57.9%	60-70%	70-75%	60%	50%
ACT	6.7%	19.5%	10.4%	12.4%	12-15%	12-25%	10%	8%

Note: penetration rates presented are for separate houses and semi-detached dwellings only. For projected numbers presented as a range, the first number reflects the initial level and the last number reflects the stabilised level.

Data source: ORER; ABS; ACIL Tasman assumptions and analysis.

The key points to note from the table above are:

- SWH penetration increases in NSW and the ACT under the Reference and High scenarios as the broad availability of natural gas in Sydney, Canberra and other major urban areas means that regulations banning the use of electric water heaters motivates uptake of both gas and solar water heaters over time.
- Victorian SWH penetration is relatively stable (or declining) due to the high current level of SWH penetration in this State and strong competition between gas and electric for new building shares
- Queensland SWH penetration rates stabilise or decline as already high solar water heater shares are eroded by competition from gas water heaters
- South Australian and Western Australian SWH penetration rates strengthen moderately for similar reasons to NSW, namely that the broad availability of reticulated natural gas motivates uptake of both gas and solar water heaters from a relatively low base.

Counterfactual penetration rates were estimated based on pre-2001 (i.e. pre MRET) SWH penetration rates, and the assumed application of regulatory measures independently of the absence of the SRES. WA penetration rates reflect consistently high historical rates of SWH use in that state, whilst NSW, Victorian, South Australian and ACT penetration rates are substantially higher than historical rates, reflecting the impact of regulations banning the use of electric water heaters in many areas. However, the solar penetration rate remains low due to the assumed high use of gas in place of solar in the absence of the SRES subsidy to SWHs.

By contrast, Queensland's assumed counterfactual SWH penetration in new buildings is higher again than pre-2001 rates, reflecting the lower uptake of natural gas for uses such as cooking and home heating, and therefore the greater use of SWH in preference to gas water heating in areas with reticulated natural gas.

5.4.2 Replacement SWH penetration

In relation to replacement water heaters, the key technology pair for this analysis is the rate of replacement of electric water heaters with solar water heaters.

As ORER installation data does not distinguish between the dwelling type or ownership, the historic penetration rates that can be implied by the water heater stock model are presented as an aggregate figure for all dwelling types. Accordingly, the projected penetration levels for separate and semi-detached dwellings are higher than historic rates, reflecting the lower penetration of SWHs in rental dwellings and flats or apartments. However, 2009 data on water heater replacement has generally been treated as an outlier due to the extremely generous government rebates available at that time prompting uptake of solar water heaters that cannot be correctly characterised as a 'replacement', but rather occurring voluntarily in response to the incentives available. Accordingly, greater weight was given to 2010 installation rates in determining projected penetration rates.

Penetration rates for solar to electric substitution are shown in Table 13 below.

Table 13 **Comparison of historic and projected electric to solar technology substitution rates**

	Historic (penetration as a % of all replacement water heaters)				Projected (assumed penetration as a % of owner occupied separate and semi-detached dwellings only)			
Jurisdiction	2008	2009	2010 (Q1-Q3)	2008-Q3 2010 avg	Reference	High	Low	Counter factual
NSW	11.5%	65.3%	26.5%	49.2%	30%	30-35%	30-20%	8%
Victoria	21.8%	40.1%	9.7%	31.3%	15%	15-25%	10%	8%
Queensland	10.1%	28.3%	26.0%	23.9%	30-35%	30-40%	30%	10-15%
South Australia	18.2%	32.7%	21.4%	25.5%	25-30%	30-35%	25-30%	8-13%
Western Australia	11.9%	30.4%	20.1%	23.3%	25-30%	30-40%	25%	20%
Tasmania	4.4%	13.6%	6.3%	9.9%	10%	10-12%	10-7%	2%
Northern Territory	10.1%	28.3%	12%	20.3%	20-30%	20-45%	20%	15%
ACT	16.9%	25.7%	13.8%	20.8%	15%	15-20%	15-10%	8%

Note: For projected numbers presented as a range, the first number reflects the initial level and the last number reflects the stabilised level.

Data source: ORER; ABS; ACIL Tasman assumptions and analysis.

Electric to solar substitution rates were assumed to increase strongly over time in Queensland and South Australia due to the application of regulations in those states that effectively prevent the replacement of electric water heaters in detached dwellings in areas with access to reticulated natural gas.

Historic data reveals only very low rates of gas to solar substitution. This is likely due to the low running costs of a gas water heater and the low capital cost of replacing a gas water heater (given the cost of connecting the house to the gas mains system has already been incurred).

Accordingly, we have adopted low rates of gas to solar substitution, which is an important factor in the projection given the increases in gas water heating penetration through the 1990s and into the last decade in all major states, with particularly noticeable increases in NSW and Western Australia.

The historic data and penetration rates for gas to solar substitution are presented in Table 14.

Table 14 **Comparison of historic and projected gas to solar technology substitution rates**

	Historic (penetration as a % of all replacement water heaters)				Projected (assumed penetration as a % of owner occupied separate and semi-detached dwellings only)			
Jurisdiction	2008	2009	2010 (Q1-Q3)	2008-Q3 to 2010 avg	Reference	High	Low	Counter factual
NSW	0.6%	0.6%	1.2%	0.9%	2%	3%	1%	0%
Victoria	2.8%	6.4%	2.8%	4.8%	3%	4%	2%	0%
Queensland	4.7%	3.4%	3.6%	4.0%	4%	5%	3%	0%
South Australia	1.6%	0.8%	0.7%	1.2%	2%	3%	1%	0%
Western Australia	6.9%	7.6%	6.2%	6.9%	6%	7%	5%	0%
Tasmania	NA	NA	NA	NA	0%	0%	0%	0%
Northern Territory	N/A	N/A	N/A	N/A	0%	0%	0%	0%
ACT	1.2%	0.8%	1.1%	1.0%	1%	3%	1%	0%

Note: For projected numbers presented as a range, the first number reflects the initial level and the last number reflects the stabilised level. Historic data for Tasmania and Northern Territory is not presented as the very low level of gas water heating results in substantial and unreliable fluctuations in the estimated penetration level.

Data source: ORER; ABS; ACIL Tasman assumptions and analysis.

5.4.3 STC creation

To project the total level of STC creation, it was necessary to assume an average level of STCs per SWH installation.

When 2010 changes to the RET/SRES schemes are taken into account, the historic level of REC/STC creation by household-scale SWHs has been relatively stable over time, and so STC creation rates assumed to hold constant at 2010 average levels per installation. These rates are set out in Table 15.

Table 15 **2010 RECs/SWH installation**

Jurisdiction	Average RECs/install Replacement units	Average RECs/install New buildings
New South Wales	31.0	30.4
Victoria	29.8	24.6
Queensland	30.0	28.9
South Australia	27.9	30.0
Western Australia	27.7	30.4
Tasmania	25.5	24.6
Northern Territory	27.1	27.2
Australian Capital Territory	29.9	31.4

Note: Data captures installations creating less than 60 RECs only to control for 2010 eligibility changes.

Data source: ORER.

Finally, the timing of STC creation is affected slightly by the extent of lag between the installation of the SWH and the creation of STCs in respect of that installation.

These lag rates can be inferred with reasonable precision from the ORER data, which specifies both installation date and the date of REC/STC creation. ORER data demonstrates a stronger lag in REC/STC creation by new building SWH installations than those in replacement SWHs, which is reflected in the assumptions set out in Table 16.

Table 16 **SWH lag assumptions**

STC creation timing	Replacement water heaters	New building installations
Quarter of installation	85%	55%
Quarter after installation	8%	25%
2 quarters after installation	5%	15%
3 quarters after installation	3%	5%

Data source: ACIL Tasman assumptions based on analysis of ORER data.

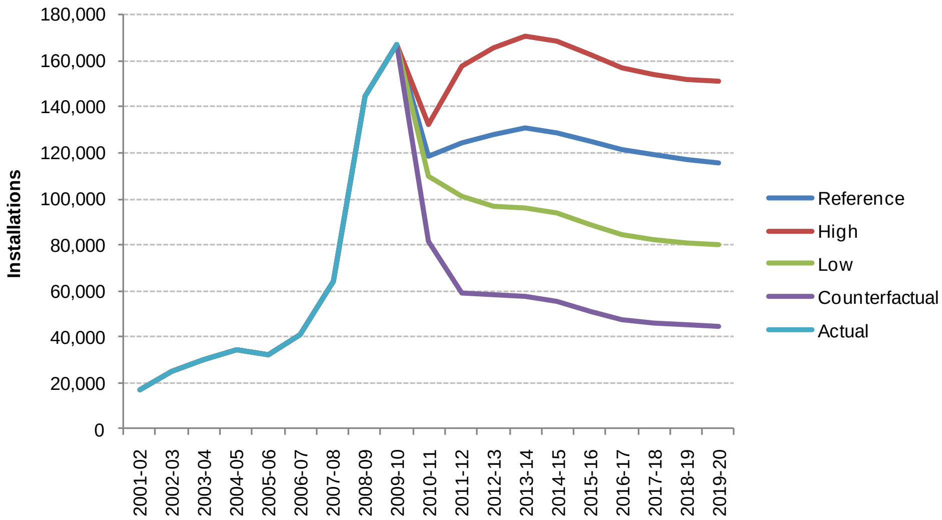
5.5 Results

Figure 41 shows the actual and projected SWH installations under each scenario.[8] The Reference Scenario sees installations level out at around 120,000 per annum, with reasonably wide High/Low bounds of 160,000 and 80,000 installs respectively.

Figure 42 shows the breakdown on installs for each jurisdiction under the Reference Scenario.

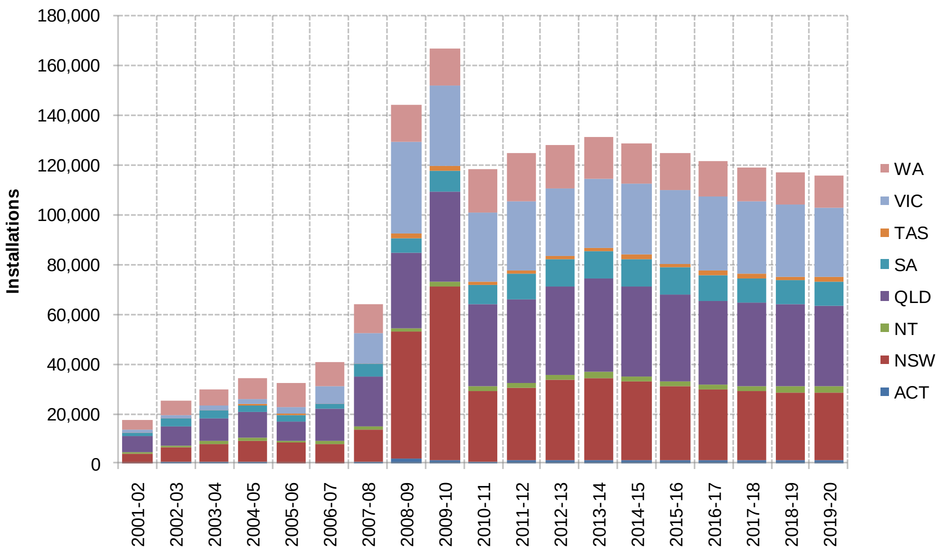
[8] Note that the scenarios for SWH do not correspond directly with the Solar PV scenarios, although they are intended to broadly correspond in relation to the Reference (Core scenario from the PV analysis) and Counterfactual cases.

Figure 41 **Projected SWH installations**



Note: Actual installations to 31 December 2010. Installations eligible for RECs/STCs only.
Data source: ACIL Tasman analysis

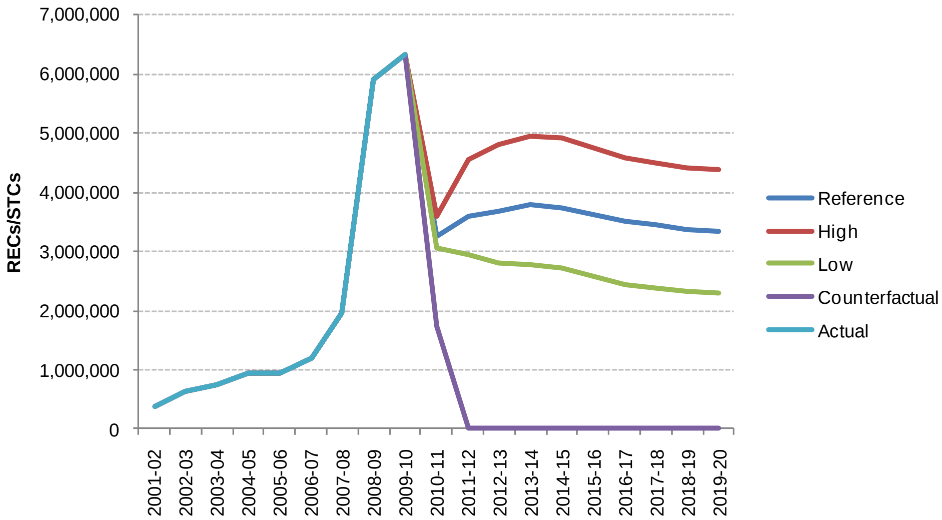
Figure 42 **Historic and projected SWH installations by jurisdiction: Reference Scenario**



Note: Actual installations to 31 December 2010. Installations eligible for RECs/STCs only
Data source: ACIL Tasman analysis

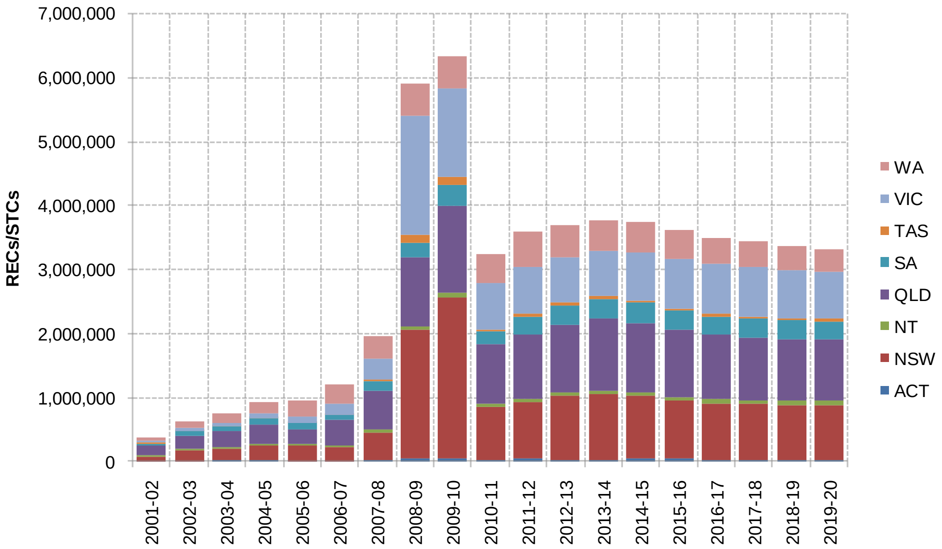
Figure 43 shows the actual REC creation and projected STCs created from SWH installs to 2019-20 under each scenario. The number of certificates created is directly related to installs as Solar Credit multipliers do not affect SWHs. Certificates created under the Reference Scenario are also broken down by jurisdiction in Figure 44.

Figure 43 **Projected REC/STC creation from SWH installs**



Note: Actual installations to 31 December 2010.
Data source: ACIL Tasman analysis

Figure 44 **Historic and projected REC/STC creation from SWH by jurisdiction: Reference Scenario**

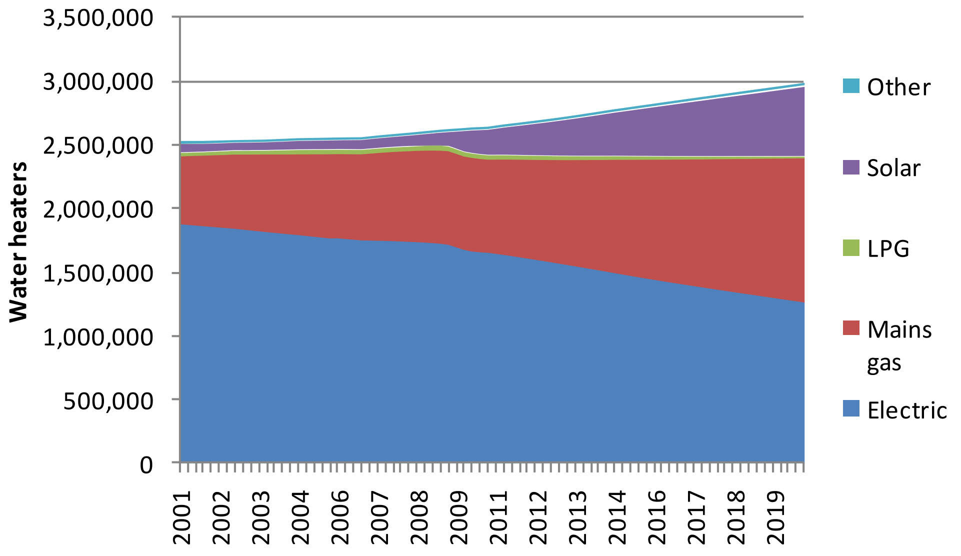


Note: Actual REC creation to 31 December 2010.
Data source: ACIL Tasman analysis

The projection results for the reference case indicates a significant increase in the share of solar water heaters in the total water heater stock, with mains gas water heating generally also increasing share within a growing total stock.

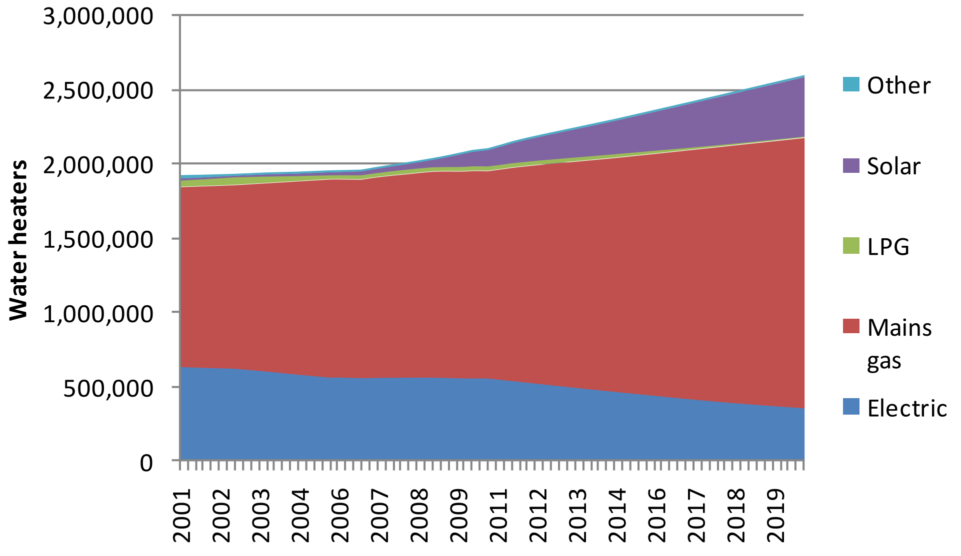
State level trends in the total water heater stock (in the Reference Scenario) are provided below, with data presented back to the start of 2001 to illustrate the historic and projected evolution of the stock since the start of the original MRET policy.

Figure 45 **NSW water heater stock, 2001 to 2020: Reference Scenario**



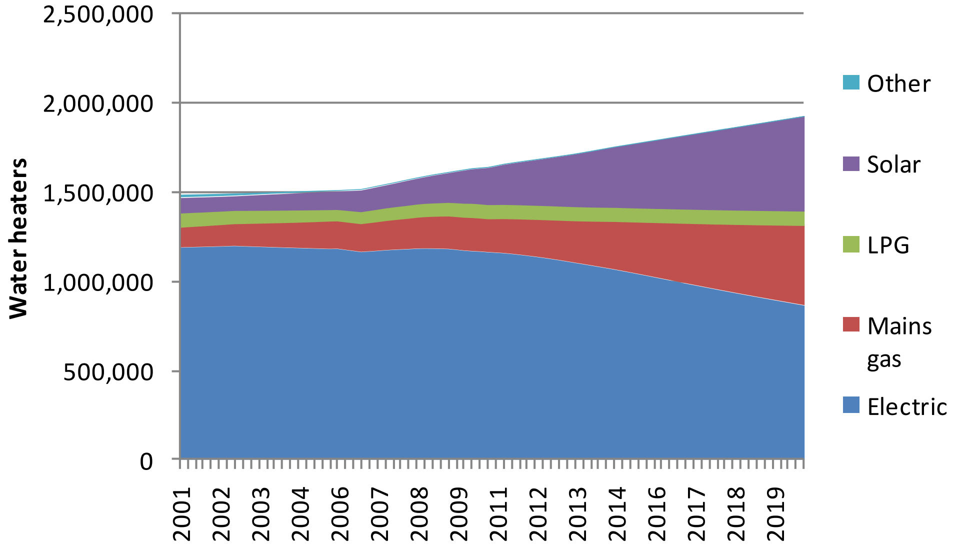
Data source: ACIL Tasman projection from 2011. Historic data to 2001 based on: DEWHA technology shares; ORER SWH installations; ACIL Tasman total water heater stock based on ABS data and DEWHA estimates of households with no water heater.

Figure 46 **Victorian water heater stock, 2001 to 2020: Reference Scenario**



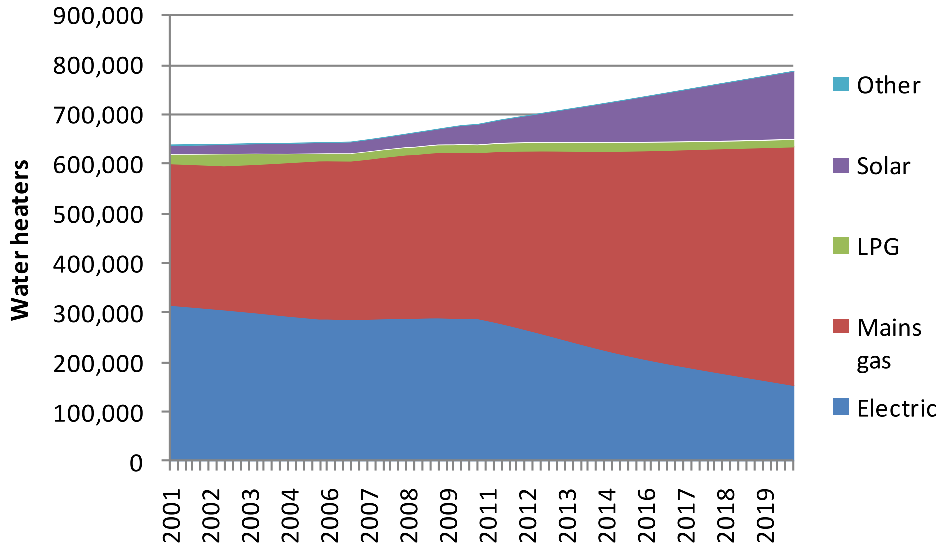
Data source: ACIL Tasman projection from 2011. Historic data to 2001 based on: DEWHA technology shares; ORER SWH installations; ACIL Tasman total water heater stock based on ABS data and DEWHA estimates of households with no water heater.

Figure 47 **Queensland water heater stock, 2001 to 2020: Reference Scenario**



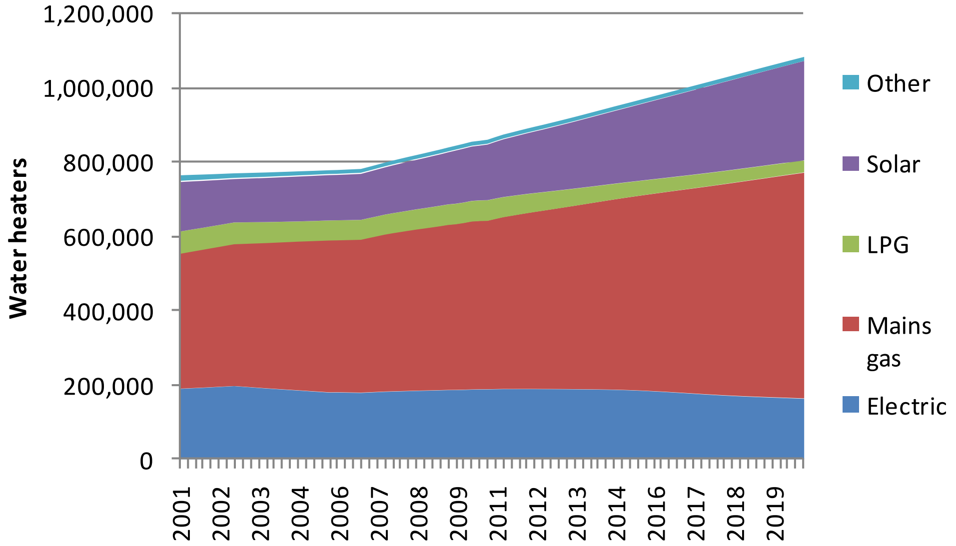
Data source: ACIL Tasman projection from 2011. Historic data to 2001 based on: DEWHA technology shares; ORER SWH installations; ACIL Tasman total water heater stock based on ABS data and DEWHA estimates of households with no water heater.

Figure 48 **South Australian water heater stock, 2001 to 2020: Reference Scenario**



Data source: ACIL Tasman projection from 2011. Historic data to 2001 based on: DEWHA technology shares; ORER SWH installations; ACIL Tasman total water heater stock based on ABS data and DEWHA estimates of households with no water heater.

Figure 49 **Western Australian water heater stock, 2001 to 2020: Reference Scenario**



Data source: ACIL Tasman projection from 2011. Historic data to 2001 based on: DEWHA technology shares; ORER SWH installations; ACIL Tasman total water heater stock based on ABS data and DEWHA estimates of households with no water heater.

6 SRES projections

This section combines the solar PV system and SWH results and examines the implications for aggregate costs to consumers and emissions abatement under SRES. As noted in section 5.1, the SWH scenarios analysed are independent of the solar PV system scenarios considered, and so we have combined our Reference Scenario SWH STC projection with every solar PV system STC projection to derive the overall STC projection.

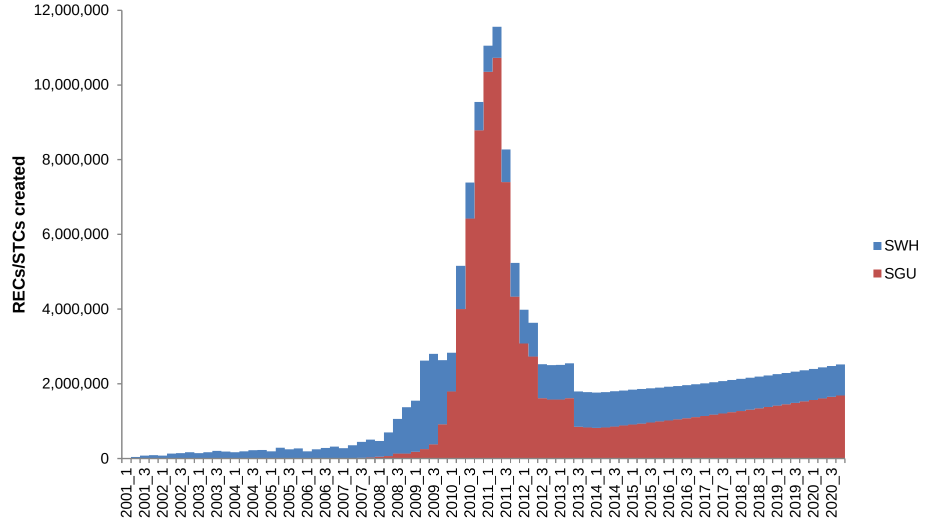
6.1 SRES costs

The first step in projecting SRES costs is to estimate the number of STCs created by solar PV and SWH installations. For solar PV systems this is achieved by allocating the projected capacity in each jurisdiction into various size bands. This is important because STCs can only be created for the first 1.5 kW for a particular installation. The number of STCs created is then based upon the ORER zone rating and Solar Credits multiplier in effect at the time.

Figure 50 shows the projected STCs created from both solar PV and SWH sources under the Core Scenario at a quarterly resolution. STCs created by solar PV systems peaks at around 10.7 million in the second quarter of 2011 – just prior to the multiplier reduction. By the end of the projection period, solar PV systems are creating around 1.7 million STCs per quarter.

Certificates created by SWH actually peaked in the third quarter of 2009 at around 2.4 million and are not projected to reach those levels again throughout the projection. By the last quarter of the projection SWH are creating around 830,000 STCs per quarter.

Figure 50 **Aggregate RECs/STCs created by type: Core Scenario**

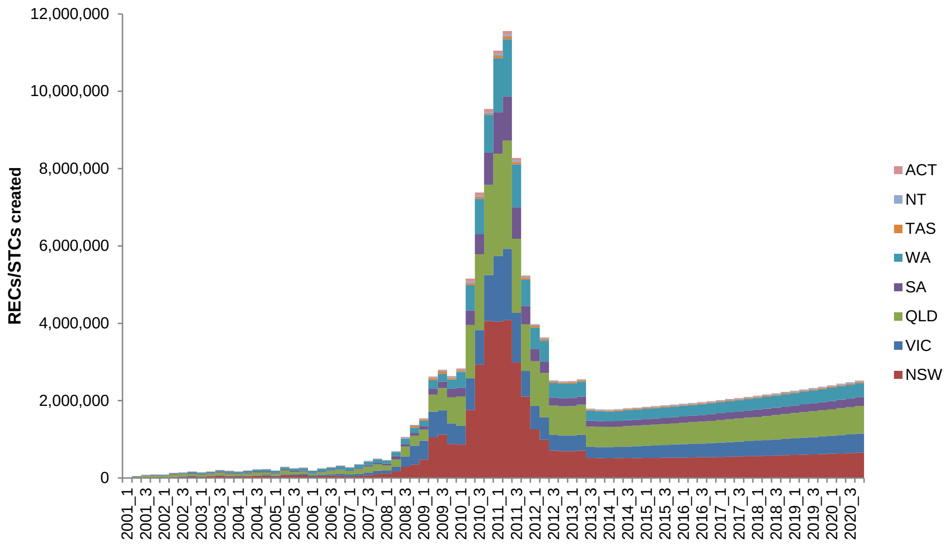


Note: Historical REC data to 31 December 2010.

Data source: ORER data, ACIL Tasman analysis

Figure 51 shows the aggregate certificates created by jurisdiction under the Core Scenario.

Figure 51 **Aggregate RECs/STCs created by jurisdiction: Core Scenario**



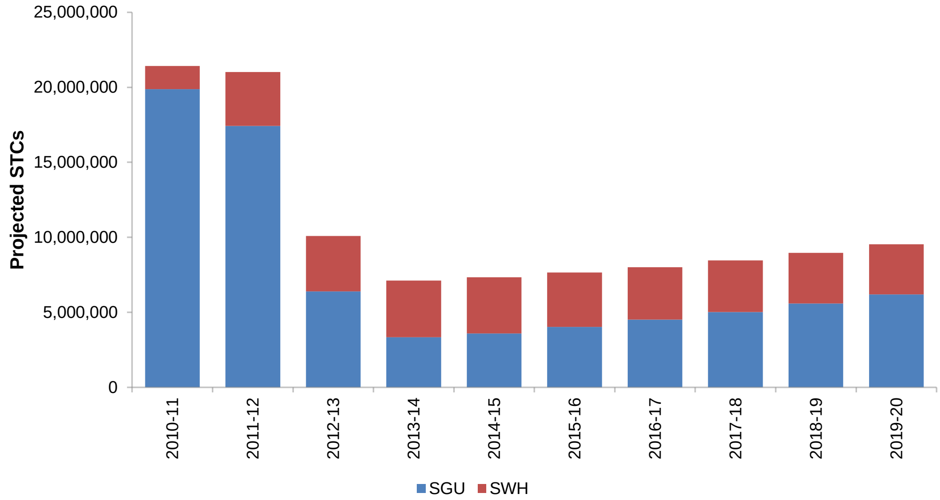
Note: Historical REC data to 31 December 2010.

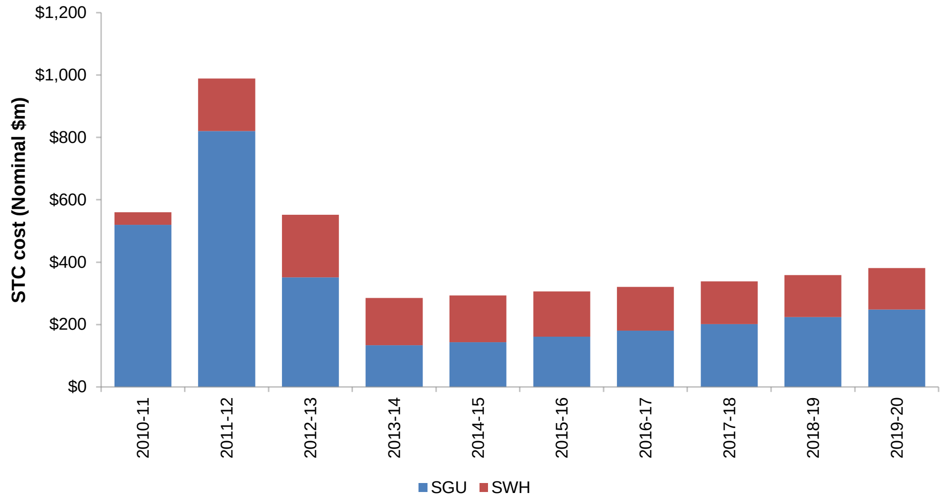
Data source: ORER data, ACIL Tasman analysis

Figure 52 shows the projected STCs created and costs on a financial year basis. Note that the certificates and costs for 2010-11 relate to the SRES period only (i.e. from 1 January 2011). The total STCs created over this period is around 109.6 million. 76.0 million (69%) of these are attributable to solar PV installations and the remainder of 33.6 million (31%) attributable to SWH.

STC costs are fixed for calendar year 2011 as ORER has set the STP at 14.8%, which is equivalent to 28 million STCs. Based on the notional cost of $40/certificate, this implies a calendar year cost of $1.12 billion. Any additional STCs created during calendar year 2011 have been carried forward as an increase to the 2012 liability. Total cost of certificates over the period amounts to $4.4 billion in nominal terms.

Figure 52 **Projected STCs created and costs: Core Scenario**





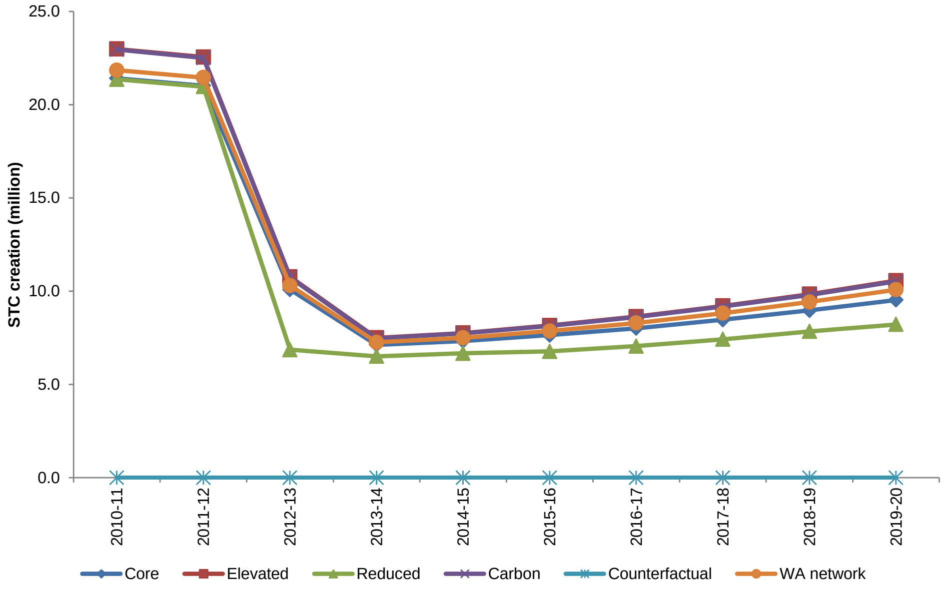
Note: The 2010-11 value relates to the period from 1 January 2011. The STC target for 2011 is fixed at 28 million. Excess STCs during 2011 count toward the calendar year 2012 requirement.

Data source: ACIL Tasman analysis

Figure 53 compares the aggregate number of certificates created across the scenarios examined. The results for the Core, Elevated Uptake, Carbon and WA network sensitivities all follow a very similar path. The Reduced Uptake Scenario is somewhat lower due to the different Solar Credits multiplier setting. The Counterfactual Scenario obviously has zero STC creation as the SRES is not assumed to exist.

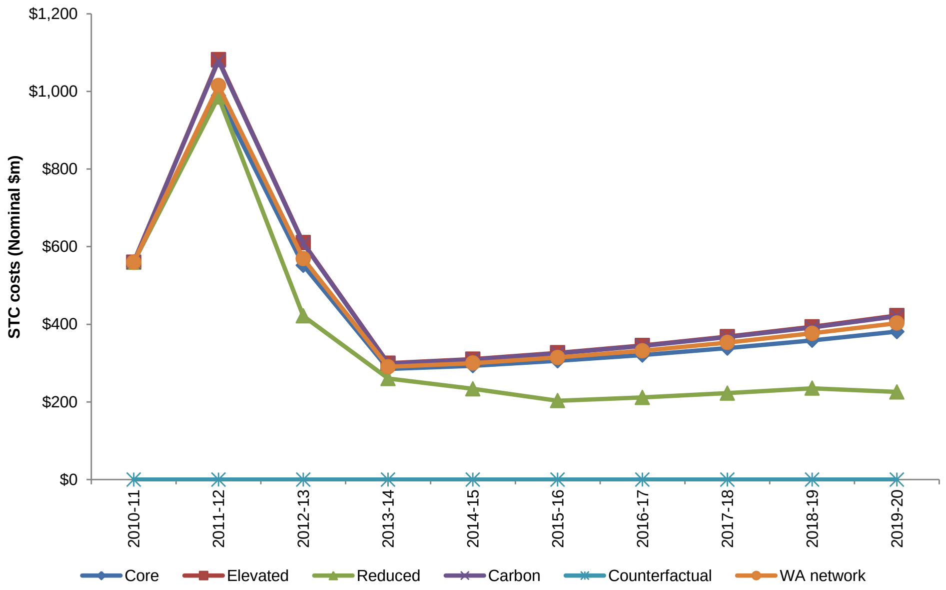
Figure 54 shows the corresponding SRES costs under each scenario.

Figure 53 **Projected STCs created: All scenarios**



Note: The 2010-11 value relates to the period from 1 January 2011.
Data source: ACIL Tasman analysis

Figure 54 **Projected STC costs: All scenarios**



Note: The 2010-11 value relates to the period from 1 January 2011. The STC target for 2011 is fixed at 28 million. Excess STCs during 2011 count toward the calendar year 2012 requirement.
Data source: ACIL Tasman analysis

Table 17 summarises the scenario results in terms of total STCs created and total cost over the period 1 January 2011 through to 30 June 2020.

Table 17 **Scenario summary results to 2019-20**

Scenario	Total certificates created (million)	Total cost of certificates (nominal $m)
Core	109.6	4,384
Elevated Uptake	118.0	4,718
Reduced Uptake	99.7	3,560
Carbon	117.6	4,705
WA network	112.8	4,514
Counterfactual	0.0	0

Note: Total certificates and costs from 1 January 2011 to 30 June 2020.
Data source: ACIL Tasman analysis

6.2 Retail price impacts

Table 18 details the projected SRES costs (expressed in cents/kWh) for end use consumers under each scenario. These values have been calculated by taking the annual SRES costs (presented in the previous section) and dividing by total end use consumption, less partial exemptions relating to emissions-intensive, trade-exposed (EITE) activities. As the costs of SRES are expressed in the form of the STP, costs are shared equally amongst all liable end users regardless of jurisdiction. Actions by jurisdictions such as NSW and ACT which have introduced gross feed-in tariffs and caused a rush of PV installations, have actually increased SRES costs for all liable end users throughout Australia.

SRES costs will continue to increase post 2020 as solar PV gains even higher levels of penetration. The SRES scheme is scheduled to finish in 2030 along with LRET. At some point during this period it is likely that PV technology will reach parity with grid electricity in all jurisdictions, even in the absence of subsidies.

Table 18 **Projected impact of SRES on retail electricity (nominal cents/kWh)**

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Core	0.30	0.53	0.29	0.14	0.14	0.15	0.15	0.16	0.17	0.17
Elevated Uptake	0.30	0.58	0.32	0.15	0.15	0.16	0.17	0.18	0.19	0.20
Reduced Uptake	0.30	0.53	0.22	0.13	0.11	0.10	0.10	0.10	0.11	0.10
Carbon	0.30	0.58	0.32	0.15	0.15	0.15	0.16	0.17	0.18	0.19
WA network	0.30	0.54	0.29	0.14	0.15	0.15	0.16	0.17	0.17	0.18
Counterfactual	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Data source: ACIL Tasman analysis

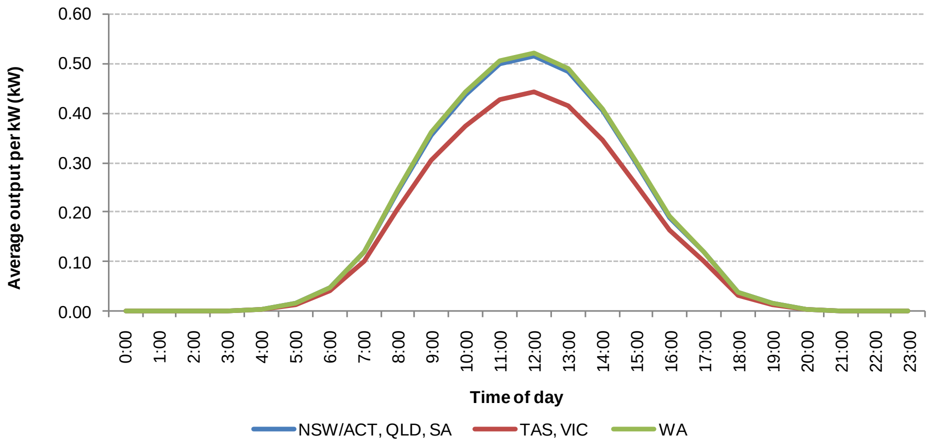
6.3 Emissions abatement

Greenhouse gas emissions are abated with the installation of solar PV and SWH systems as they displace electricity from the grid – in the case of solar PV systems – and electricity, natural gas or LPG in the case of SWHs.

6.3.1 Solar PV systems

The output profile of solar PV systems is somewhat distinct in that they only produce power during daylight hours, with average peak output occurring around mid-day. Typical output profiles, which have been adjusted according to ORER zone ratings, are shown in Figure 55 for each jurisdiction.

Figure 55 **Average solar PV output by time of day per kW of capacity**



Note: Profiles adjusted to match ORER zone ratings in each jurisdiction. NSW/ACT, QLD and SA profile implies an annual capacity factor of 15.8%; TAS/VIC: 13.5%; WA: 16%.
Data source: ACIL Tasman analysis

The amount of grid electricity displaced from the projected installations is an output of the SRES model. As each new PV system is installed, it adds to the stock of PV systems displacing grid power. It should be noted that the displaced energy relates to own use consumption (avoided household acquisitions from the grid) as well as PV system exports to the grid. That is, the measure of displaced energy is equal to total PV output, adjusted to reflect losses avoided as a result of consuming electricity at the source, rather than from remote large-scale generation sources.

Estimated grid electricity displaced under each scenario is detailed in Table 19. The total energy displaced in 2019-20 ranges from around 2,500 GWh to 3,300 GWh under the various SRES scenarios. The Counterfactual Scenario sees much lower level of electricity displaced, given the dramatically lower PV uptake.

The projected amount of electricity displaced from PV is slightly lower than the implied target of 4,000 GWh set with the creation of SRES (the ERET target was reduced from 45,000 GWh to 41,000 GWh under the LRET). However, when the electrical energy displaced from SWH is added, the total would exceed the notional 4,000 GWh target.

Table 19 **Estimated grid electricity displaced from PV uptake under SRES (GWh)**

Scenario	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Core	143	673	940	1,160	1,384	1,635	1,916	2,228	2,576	2,962
Reduced Uptake	143	671	903	1,082	1,269	1,465	1,684	1,931	2,207	2,513
Elevated Uptake	155	731	1,022	1,267	1,517	1,800	2,119	2,477	2,878	3,327
Carbon	154	728	1,019	1,263	1,511	1,792	2,109	2,465	2,865	3,311
Counterfactual	8	43	68	94	124	157	194	235	281	332
WA Network	146	688	963	1,192	1,426	1,690	1,988	2,322	2,697	3,116

Note: For systems installed from 1 January 2011 only.
Data source: ACIL Tasman analysis

Given the projected energy values and output profiles, ACIL Tasman analysed the impact of this upon greenhouse gas emissions from the electricity sector in an attempt to calculate the 'marginal' emissions intensity. This was done by taking the output profiles and adjusting demand within *PowerMark* accordingly. Total grid emissions from this scenario was then compared to a reference case to estimate the greenhouse gas abatement achieved.

Solar PV output occurs mainly during the day when the emissions intensity of grid electricity is lower compared with overnight periods. As a result, the reduction in demand during these periods tends to displace lower emission plant such as gas-fired CCGT and OCGT rather than coal plant. Figure 56 compares the average NEM emissions intensity from the modelling with the marginal emissions intensity of energy displaced by PV output.

Average emissions intensity under the 'No carbon' scenario starts at around 0.89 tonnes CO_2-e/MWh and falls to about 0.79 tonnes CO_2-e/MWh by 2020. By comparison, the marginal emissions intensity of electricity displaced by PV starts at around 0.5 tonnes CO_2-e/MWh, rises slightly, then falls, reaching 0.53 tonnes CO_2-e/MWh by 2020. The reason the marginal value varies between 0.5 and 0.6 tonnes CO_2-e/MWh during this period is due to the emissions intensities of the technologies PV energy is displacing:

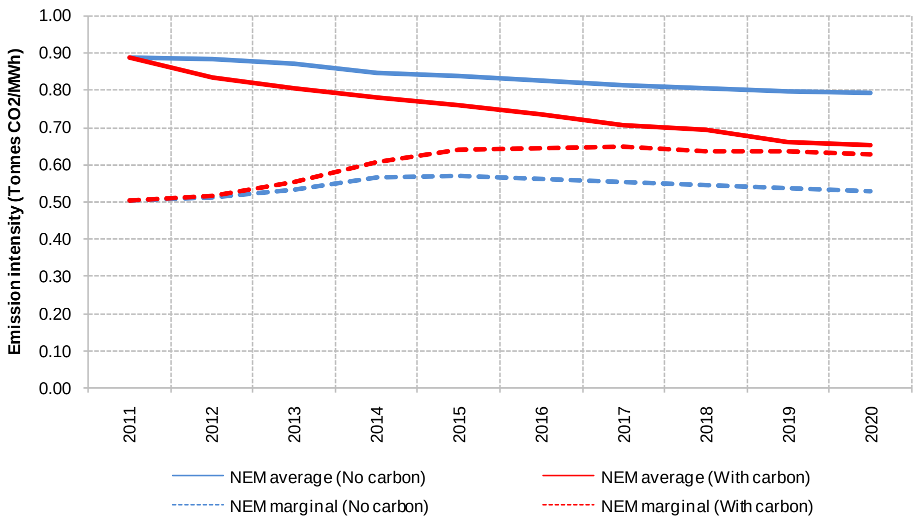
- gas-fired CCGT plant (emissions intensity of around 0.4 tonnes CO_2-e/MWh)
- gas-fired OCGT plant (emissions intensity of around 0.6 tonnes CO_2-e/MWh).

As coal plants generally have much lower marginal costs than gas plant, the modelling shows little change in the output of coal plant (i.e. it is rare that coal-fired generation is the marginal plant throughout the day).

PV output does not reduce hydro output as operators are assumed to be energy constrained on an annual basis. While they may alter the timing of their generation as a result of PV output, it is assumed their annual output is constant.

A significant gap remains between the average and marginal values in the 'No carbon' scenario as PV continues to displace gas-based technologies throughout the projection period.

Figure 56 **Average grid and marginal emissions intensity for the NEM**



Data source: ACIL Tasman PowerMark modelling

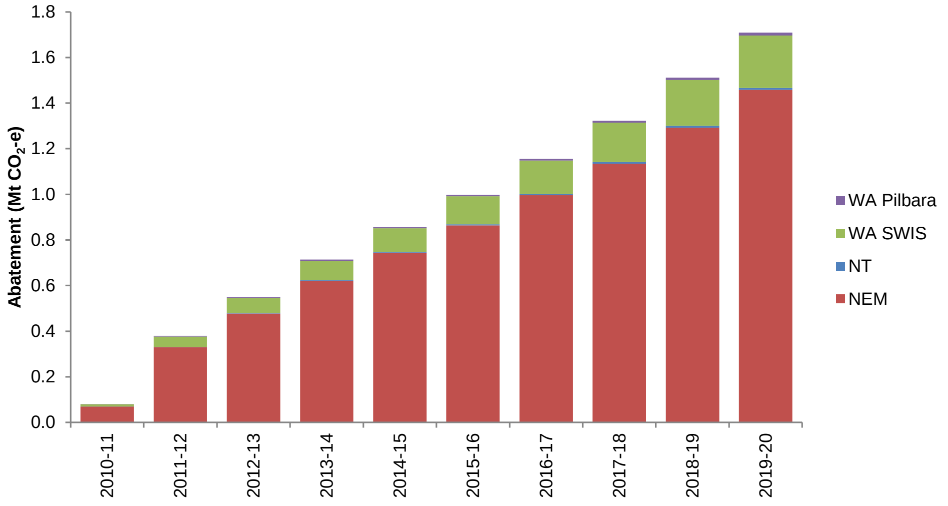
The gap under the 'With carbon' scenario however is somewhat different. This narrows significantly, such that by 2020 the two series are very close together. This is a result of the carbon price which alters the merit order and makes coal plant more marginal. A similar finding occurs in the SWIS – although much less pronounced. Average emissions intensities were used for the Pilbara, and NT grids due to their reliance of natural gas.

As energy generated by solar PV systems occurs at the end user level, it also reduces grid losses. Therefore the marginal intensity values for displaced energy shown in Figure 56 have been grossed up for average network losses.

Figure 57 shows the estimated greenhouse gas emissions abatement that results from the level of solar PV uptake under the Core Scenario by network. By the end of the projection period the stock of solar PV systems abates around 1.7 Mt of CO_2-e annually.

Total abatement for the period is around 9.3 Mt CO_2-e. It is important to note that this abatement will continue past the end of the projection period.

Figure 57 **Abatement of greenhouse gas emissions from solar PV output: Core Scenario**

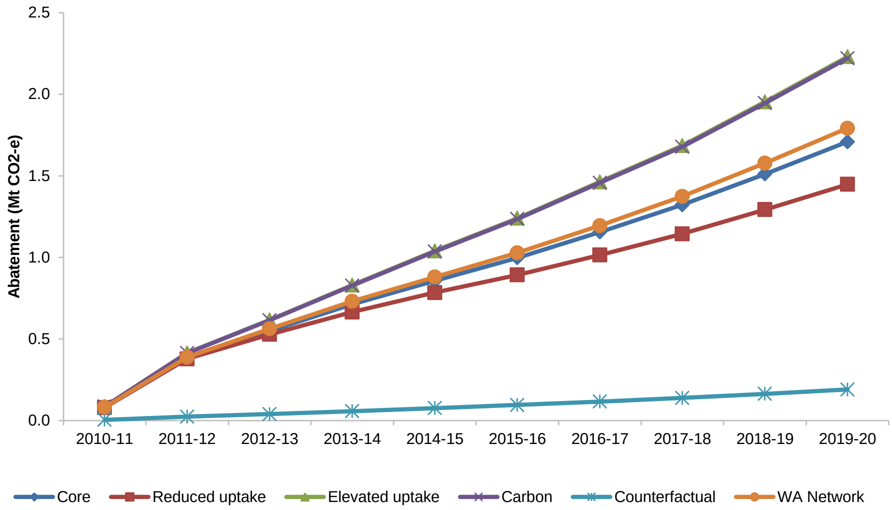


Note: Calculated as PV output multiplied by the marginal intensity value, adjusted for network losses.
Data source: ACIL Tasman PowerMark modelling

Figure 58 compares the aggregate abatement attributable to solar PV installations across all scenarios. The highest abatement is achieved in the Elevated Uptake and Carbon scenarios. The Counterfactual Scenario sees a much lower level of abatement as a result of significantly lower levels of capacity installed.

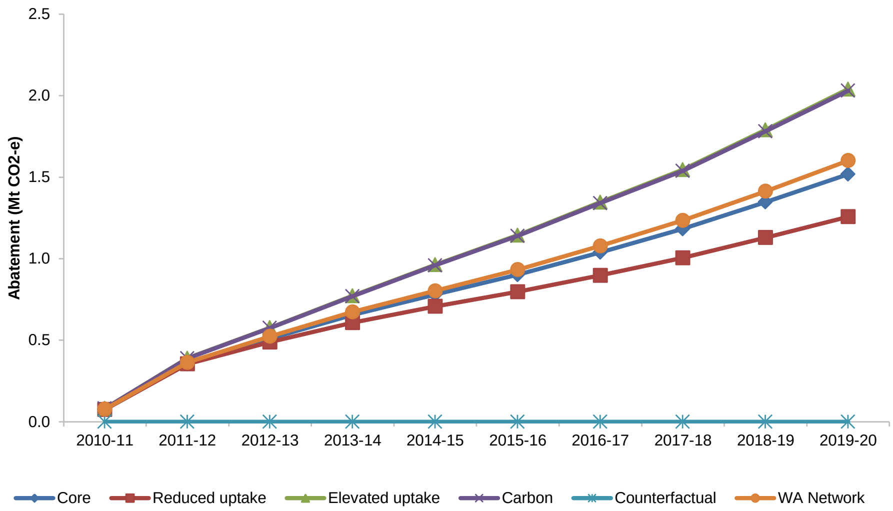
Figure 59 shows the abatement levels achieved under each scenario relative to the Counterfactual Scenario (i.e. the abatement that would have been achieved from solar PV systems in the absence of SRES).

Figure 58 **Abatement of greenhouse gas emissions from solar PV output: All scenarios**



Note: Calculated as PV output multiplied by the marginal intensity value, adjusted for network losses.
Data source: if outside data used and we have charted it

Figure 59 **Abatement of greenhouse gas emissions from solar PV relative to counterfactual: All scenarios**



Note: Calculated as abatement attributable to PV installations less abatement under the Counterfactual Scenario.
Data source: if outside data used and we have charted it

6.3.2 Solar water heaters

Abatement attributable to SWH installations relates to the reduction in energy use (and therefore emissions) from alternate heating technologies. For each of the SWH scenarios, ACIL Tasman has estimated the greenhouse gas emissions from each technology. Average energy use by electric, gas and LPG water heaters was inferred from state-level data presented in the DEWHA study and ACIL Tasman estimates of the total stock of each type of water heater.

In the absence of strong evidence to support an alternative assumption, energy use per fossil-fuelled water heater in each state was held constant at 2010 levels over the projection period.

Table 20 **Average energy use by water heater type**

Jurisdiction	Electric	Gas	LPG
	MWh/unit/year	GJ/unit/year	GJ/unit/year
New South Wales	2.9	13.7	13.5
Victoria	3.0	14.4	12.6
Queensland	2.3	10.9	10.5
South Australia	2.5	11.1	11.7
Western Australia	2.8	12.4	12.6
Tasmania	3.0	14.4	12.6
Northern Territory	2.3	10.9	10.5
Australian Capital Territory	3.1	15.3	13.5

Note: Tasmanian and Northern Territory Gas and LPG energy use set equal to Victorian and Queensland use respectively, and Australian Capital Territory LPG use set equal to NSW use, due to rounding errors in alternative estimates.

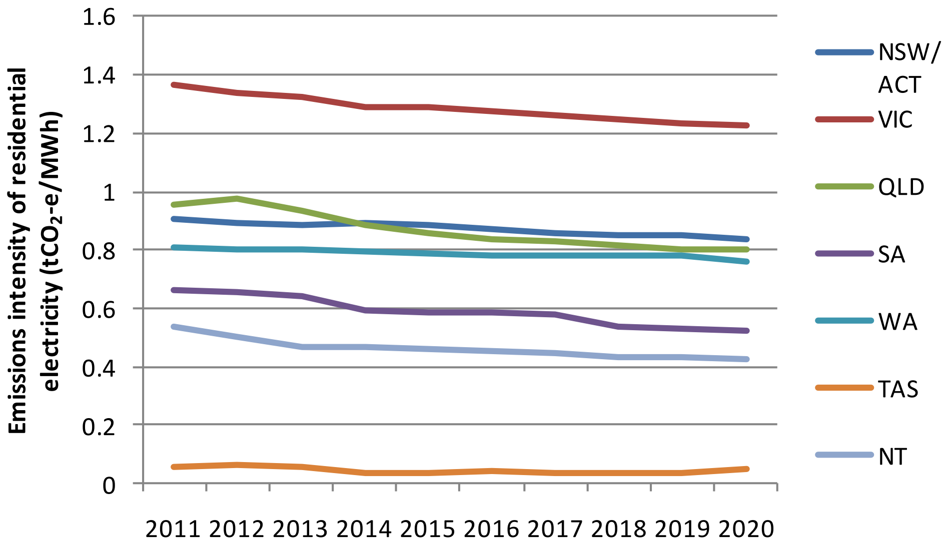
Data source: ACIL Tasman assumptions based on analysis of DEWHA (2008) data.

Emissions factors for electric, gas and LPG fuelled hot water systems were applied to projected total units installed in order to calculate total greenhouse gas emissions from hot water.

The emissions factors for electricity used in water heating were taken from *PowerMark* modelling as being the average emissions intensity of electricity supply in the relevant grid (in the absence of a carbon price), adjusted for losses in delivery to household consumers. The average emissions intensity of electricity supply was used due to the largely 'off-peak' nature of electricity used to heat water, which will tend to more strongly reflect the average emissions intensity of the grid in a given location (in contrast to the electricity displaced by solar PV generation, which will tend to be the marginal day-time generation and have a lower emissions-intensity reflecting the increased use of gas and hydro at those times). Transmission of electricity between states was not taken into account.

These loss adjusted emissions factors for each jurisdiction were as set out in Figure 60.

Figure 60 **Electricity emissions intensity**

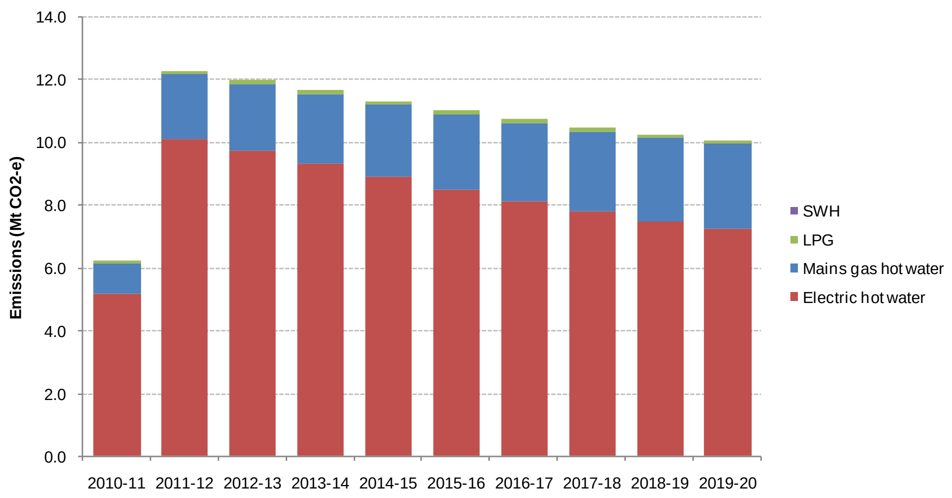


Source: PowerMark modelling.

Mains natural gas emissions factors were estimated at the state level on the basis of the July 2010 National Greenhouse Accounts Factors. LPG emissions factors were constant for all states at 0.0649 tonnes CO_2-e/GJ.

Figure 61 shows the projected greenhouse gas emissions arising from water heating by technology throughout Australia under the Core Scenario. Aggregate emissions are projected to fall from around 12 Mt CO_2-e in 2011-12 down to around 10 Mt CO_2-e by 2019-20. This is due to the increased penetration of SWH and gas-based heaters at the expense of electric systems.

Figure 61 **Projected emissions from hot water systems: Core Scenario**

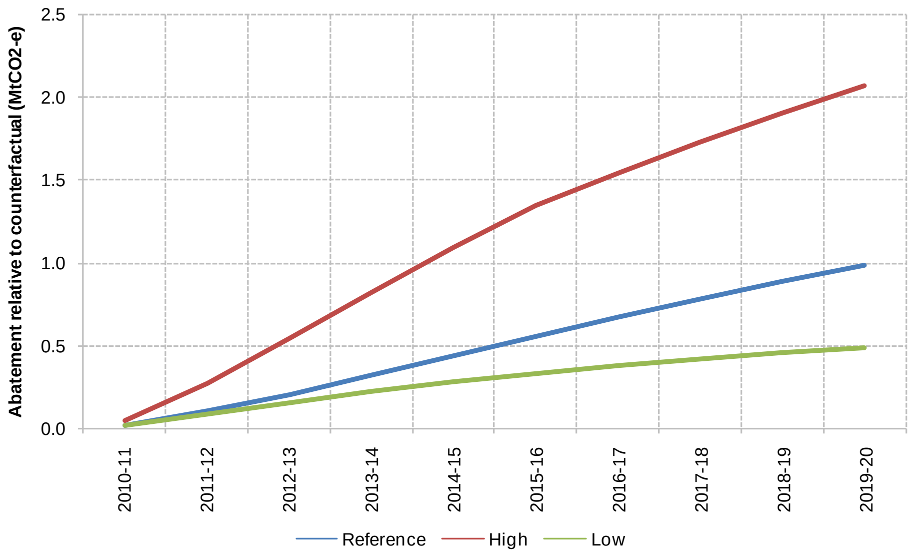


Note: 2010-11 relates to emissions from 1 January 2011 only.

Data source: ACIL Tasman analysis

Figure 62 shows the abatement relative to the counterfactual under the Core, High and Low SWH projections.

Figure 62 **Abatement of CO_2-e from SWH relative to counterfactual: All scenarios**



Note: Relates to abatement arising from installations that occur after 1 January 2011 only.
Data source: ACIL Tasman analysis

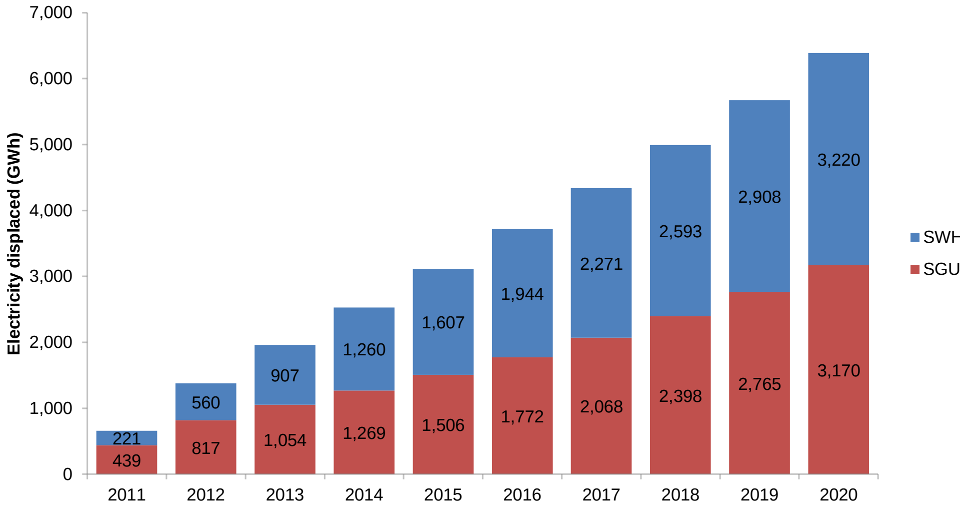
6.3.3 Aggregate electricity displacement

The combined impact of SWH and solar PV in terms of electricity displacement is shown in Figure 63. Note that this energy is presented in gross terms (i.e. is not net of the Counterfactual Scenario).

By 2020, total displacement equates to almost 6,400 GWh across the nation. Of this, 3,170 GWh is attributable to solar PV, and 3,220 GWh attributable to SWH.

Under the carbon case, the estimated aggregate electricity displaced is larger at just under 6,774 GWh.

Figure 63 **Aggregate electricity displaced: Core Scenario**

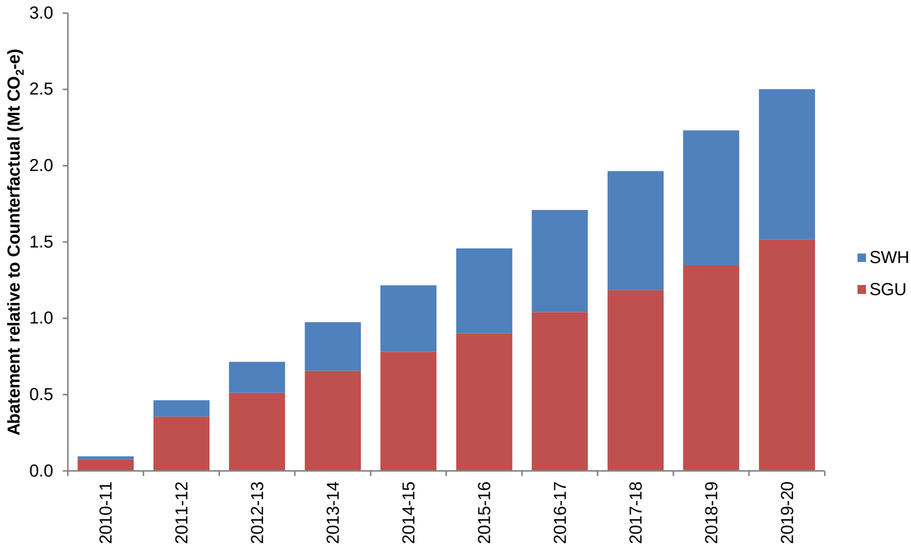


Data source: ACIL Tasman analysis

6.3.4 Aggregate emissions abatement

Figure 64 shows the aggregate abatement relative to the counterfactual broken down into SWH and solar PV components. Abatement rises to around 2.5 Mt CO_2-e per year by the end of the projection period.

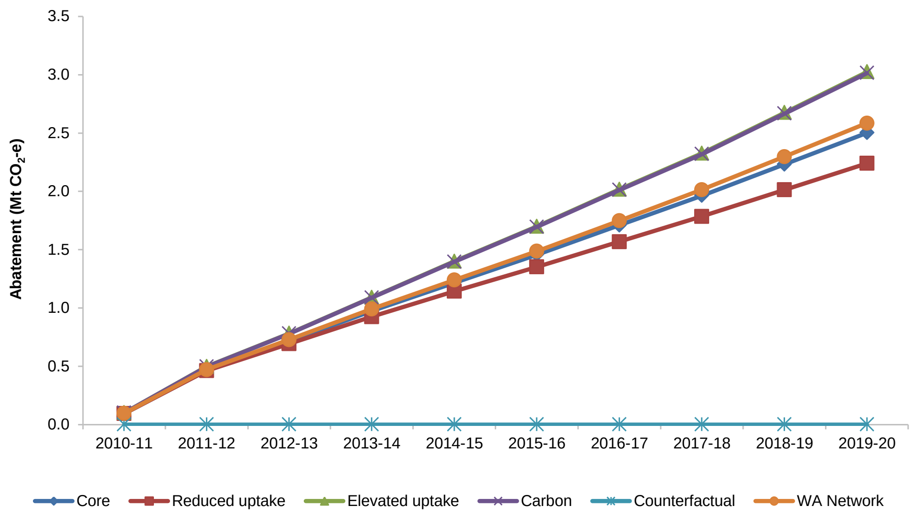
Figure 64 **Total abatement relative to counterfactual: Core Scenario**



Note: Uses Reference case SWH projections
Data source: ACIL Tasman analysis

Figure 65 shows aggregate abatement relative to the counterfactual under each of the scenarios examined. Abatement levels by the end of the projection period range from a low of 2.2 Mt CO_2-e per year (Reduced Uptake Scenario) to 3.0 Mt CO_2-e per year under the Elevated Uptake and Carbon scenarios.

Figure 65 **Total abatement relative to counterfactual: All scenarios**



Note: Uses Reference case SWH projections for all scenarios
Data source: ACIL Tasman analysis

6.4 Economic cost of abatement

Calculating the cost of abatement is fraught with difficulty and is commonly incorrectly done. Herein, we define the 'economic cost' of solar PV installs as the cost premium they incur for the economy as a whole when replacing grid-based electricity.

To calculate this cost, we first need to calculate the annualised resource costs[9] of PV installs. This is required because PV systems will continue to operate well beyond the projection period (we have assumed a standard economic life for PV panels of 25 years and 10 years for inverters). An annualised cost is also required due to the upfront nature of the cost profile of PV systems. It takes into consideration the upfront cost of the system and any ongoing maintenance and replacement costs (such as inverters). This is done using the nominal 10% discount rate as used in calculating financial paybacks and converts all costs into an equivalent annuity.

From this value we deduct the marginal or avoidable economic cost of electricity produced from the system. That is, the energy component of retail

[9] This annualised cost is a resource cost in that it ignores the source of funds (i.e. it is the total cost of the system).

costs as distinct from the variable components of retail bills.[10] This provides the economic resource costs as shown in Table 21. In essence this is the premium we, as a society, have paid in substituting PV electricity for lower-cost electricity available from the grid.

Table 21 **Economic cost of PV installations (Nominal $m): Core Scenario**

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
NSW	14.9	69.6	90.2	105.3	119.5	133.7	147.8	161.9	175.7	189.2
Victoria	7.2	31.0	42.1	50.8	59.1	68.1	77.9	88.5	99.9	112.2
Queensland	9.7	45.0	66.6	82.9	97.9	113.6	129.7	146.3	163.2	180.2
South Australia	3.4	15.7	20.1	23.6	26.8	30.2	33.6	37.2	40.7	44.3
Western Australia	3.9	18.3	26.0	32.1	37.9	43.6	49.3	54.8	60.1	65.1
Tasmania	0.3	1.5	2.7	3.8	4.7	5.7	6.7	7.6	8.5	9.4
Northern Territory	0.1	0.4	0.6	0.8	0.9	1.1	1.2	1.3	1.4	1.5
ACT	0.3	1.3	1.4	1.5	1.6	1.6	1.7	1.8	1.9	1.9
Australia	39.8	182.5	249.6	300.8	348.5	397.6	448.0	499.3	551.4	603.7
Electricity displaced	143	673	940	1,160	1,384	1,635	1,916	2,228	2,576	2,962
Economic cost/MWh	$277.7	$271.3	$265.7	$259.3	$251.8	$243.2	$233.9	$224.1	$214.0	$203.8

Note: Calculated as the annualised resource cost of PV installs, less the energy component of retail electricity costs
Data source: ACIL Tasman analysis

These aggregate costs increase over time as more PV systems are added. However, the economic cost per unit of PV generation used in place of grid-supplied electricity declines over time as system costs decline and wholesale energy costs increase.

An economic cost of the abatement delivered by solar PV systems can be calculated by dividing the economic resource costs by abatement achieved from the installations. The calculated economic cost of abatement for the Core Scenario is detailed in Table 22 and shown graphically in Figure 66.

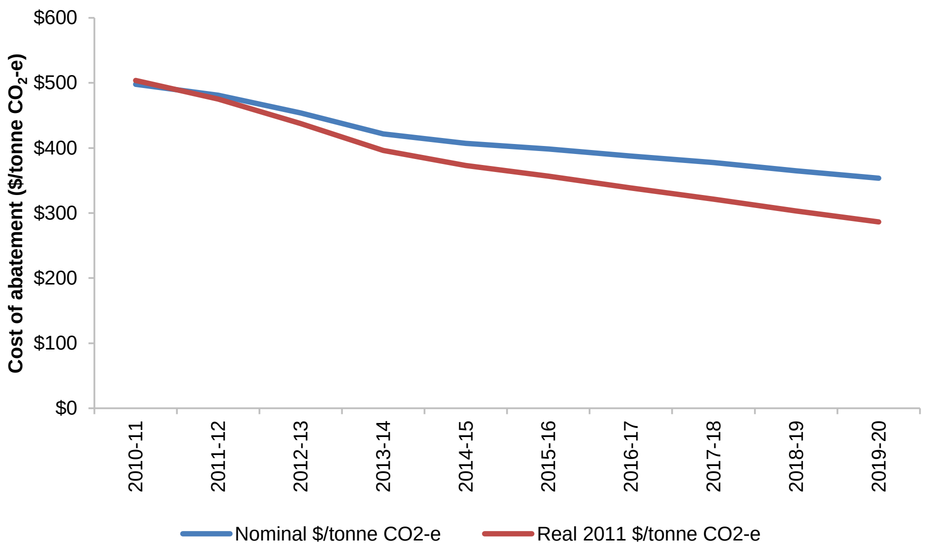
[10] PV sourced electricity may also have network cost impacts – positive or negative which are ignored for this exercise.

Table 22 **Economic cost of abatement from solar PV: Core Scenario**

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Abatement (Mt CO_2-e)	0.08	0.38	0.55	0.71	0.86	1.00	1.16	1.32	1.51	1.71
Total economic cost ($m nominal)	$39.8	$182.5	$249.6	$300.8	$348.5	$397.6	$448.0	$499.3	$551.4	$603.7
Economic cost of abatement (nominal $/tonne CO_2-e)	$498	$481	$454	$422	$407	$398	$388	$377	$365	$353
Total economic cost (real 2011 $m)	$40.3	$180.4	$242.8	$285.3	$322.0	$358.1	$393.4	$427.5	$460.3	$491.6
Economic cost of abatement (real 2011 $/tonne CO_2-e)	$504	$475	$437	$396	$373	$357	$338	$322	$303	$286

Data source: ACIL Tasman analysis

Figure 66 **Economic cost of abatement from solar PV: Core Scenario**



Data source: ACIL Tasman analysis

This indicates the PV technology offers an expensive means of achieving abatement, at costs of $300-$500/tonne CO_2-e in real 2011 dollars.

However, this analysis does not illustrate the cost of abatement delivered by the SRES policy itself, or other policies that support solar PV systems. This is primarily because it is difficult to disaggregate the abatement (and therefore cost) that should be attributed to the SRES as distinct from other policies that support solar PV installations, or from economic distortions that implicitly subsidise solar PV installations.

Firstly, the abatement delivered by, or costs incurred by, the SRES cannot be easily distinguished from that delivered or incurred by jurisdictional feed-in tariffs. Whilst the change in uptake relative to the counterfactual does illustrate the incremental impact of the SRES in addition to other policies, the non-linear response of consumers to improving paybacks tends to overstate the attribution of abatement (and therefore cost) to the 'second' policy assumed to be imposed 'on top' of other pre-existing policies, in this case the SRES. If the reverse counterfactual were to be adopted, with feed-in tariffs being notionally added to the prior existence of the SRES, the abatement delivered by the feed-in tariffs would tend to be overstated equally. It is therefore very difficult to correctly attribute abatement and cost to the SRES on a stand-alone basis.

Secondly, the SRES and feed-in tariffs build on an implicit (and largely unintended) subsidy afforded PV systems through the current structure of retail electricity bills in Australia. In general, the variable component of retail electricity tariffs do not reflect the economically variable or avoidable component of the true cost of delivering electricity to retail consumers. Whilst around 90% of the final retail bill is provided as a variable component, the true fixed proportion of this cost, economically speaking, is far greater than 10%.

Accordingly, irrespective of feed-in tariffs or other subsidies, a household installer of a PV system is afforded an implicit subsidy for every unit of electricity produced by a PV system and consumed by the owner of the system. The value of this implicit subsidy is equal to the difference between the variable component of the retail bill and the true economically variable component of the cost of electricity.

This situation can lead to households installing PV systems on the basis of a positive private financial return whilst imposing a net economic cost on society as a whole. In other words, there is a private financial gain which relies on transferring economic costs to other users of the energy system. These externalised costs include reducing the base of energy use over which network tariffs are recovered, therefore transferring the largely fixed cost of maintaining the network on to energy users that do not have PV systems, and similarly transferring compliance costs of schemes such as the LRET and SRES on to other energy users.

These two factors imply that, rather than considering the cost of the SRES as a stand-alone policy, policy-makers should consider the overall economic cost of supporting solar PV systems in explicit and implicit ways. Any disconnection between the level of those costs and the incidence of those costs (whether explicit or implicit) will tend to artificially increase the overall economic cost in two main ways:

- The overall level of solar PV installation will increase, increasing total economic cost (unless the true cost of PV systems reduces to below the true cost of grid-supplied electricity)

- The timing of installation of solar PV systems is changed: recent policy settings have had the primary effect of bringing forward the installation of solar PV systems as well as increasing the total level of installation. Given solar PV system costs are projected to decline, this has a compositional effect of substituting current-day (expensive) systems for future, lower-cost systems, at a high aggregate economic cost.

In summary, whilst the precise effect of individual measures is hard to disaggregate, subsidies such as SRES and jurisdictional FiT schemes have a high economic cost and correspondingly deliver greenhouse gas abatement at high cost.

Significantly, even in the absence of such policies, implicit subsidies afforded solar PV systems will tend to motivate behaviour that imposes non-trivial economic costs on the energy system as a whole, whilst delivering abatement at high (albeit declining) costs.

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