25 August 2022

Report to Australian Building Codes Board

National Construction Code 2022

Decision Regulation Impact Statement for a proposal to increase residential building energy efficiency requirements

APPENDICES

About ACIL Allen

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The proposed changes to the energy efficiency provisions for Class 1 buildings are set out in Table A.1.

As part of the restructure of NCC 2022, energy efficiency DTS elemental provisions in Volume Two are included in the Housing Provisions. Further information about the restructure of NCC 2022 can be found on pages 2 to 6 of the NCC 2022 PCD1 Supporting Information[1].

Table A.1 Summary of proposed energy efficiency changes for Class 1 buildings

NCC Reference	Changes and commentary
Part H6 Energy efficiency H6O1 and H6F1 Objectives and Functional Statements	The Objectives and Functional Statements are expended to reflect the policy intent outlined in the Trajectory. Notably, the Objectives and Functional Statements are explanatory information, that is non-mandatory and informative.
H6P1 Building fabric H6P2 Energy usage	The existing Performance Requirements for Class 1 dwellings in Volume Two, P2.6.1 building fabric and P2.6.2 Services, were quantified to account for the overall stringency increase and the whole-of-home requirements.
H6V2 Verification using a reference building (VURB)	The VURB has been updated to reflect the stringency increase under the proposed DTS elemental provisions. Operating schedules for heating and cooling, thermostat settings, and maximum occupancy are included to provide more clarity for modelling. The Class 1 VURB only covers the building fabric requirements. This is different to the VURB for Class 2 SOUs (Volume One). To satisfy the whole-of-home requirements, DTS elemental provisions, H6P2 or other whole-of-home options can be used.
Specification 42 Using house energy rating software	Due to the restructure of the NCC undertaken for improved useability, the NatHERS compliance option is in Specification 42. As previously mentioned, the proposed requirements for heating and cooling loads are updated to reflect the one-star stringency increase.

[1] https://consultation.abcb.gov.au/engagement/ncc-2022-public-comment-draft/supporting_documents/NCC%202022%20PCD%20Supporting%20information.pdf

NCC Reference	Changes and commentary
	Credits for outdoor living areas and ceiling fans are retained with a one-star increase. NatHERS whole-of-home software is included for potential referencing.
Housing provisions (DTS elemental provisions) Part 13.2 Building fabric	Newly proposed insulation requirements have a different structure to the current NCC 2019 provisions. Instead of specifying minimum R-Values to cover all cases, a broad range of building element properties and R-Values (to produce acceptable performance) are presented in a series of look-up tables. This will save practitioners from needing to calculate the Total R-Values themselves.
13.2.3 Roof	Under the new structure of these provisions, minimum R-Values for roof insulation are listed in tables for two types: pitched roof with flat ceiling and flat roof for the 8 NCC climate zones. Minimum R-Values are determined by factors including roof ventilation, reflective insulation, under-roof insulation and solar absorptance in the look-up tables. There is a cap for solar absorptance values in climate zones 1 to 5 at 0.64 for roofs. However, higher solar absorptance values can still be used for cold climates. 13.2.3 requires mitigation of thermal bridging in steel-framed roofs. Several options are available to demonstrate that thermal bridging is mitigated, through either: – meeting a minimum Total R-Value for a flat ceiling below a pitched roof, or – meeting a minimum Total R-Value requirement for the roof in a flat, skillion or cathedral roof, or – increasing the insulation between ceiling or roof framing elements, or adding a continuous layer of insulation above or below the ceiling or roof framing. The thermal bridging mitigation requirements are distinct from the existing thermal break requirements of Clause 13.2.3(7).
13.2.4 Roof lights	The roof light provisions are updated to align with the changes made to the roof light provisions in NCC 2019 Volume One.
13.2.5 External walls	The proposed wall insulation requirements focus on providing solutions based on the thermal mass of the wall. The wall insulation requirements are based on the dominant construction type for the climate zone: – brick veneer walls in climate zones 2, 4, 5, 6 and 7 – concrete block walls in climate zones 1 and 3; – framed lightweight walls in climate zone 8. Provisions for a second wall type with a different level of thermal mass are also provided. For example, framed lightweight walls are provided in climate zones 1 and 3.

NCC Reference	Changes and commentary
	Minimum R-Values for different wall types in each climate zone are provided in look-up tables, in consideration of factors including solar absorptance, length of overhangs and wall height. There is a cap on solar absorptance values in climate zones 1 to 5 of 0.7 for walls. However, higher solar absorptance values can still be used in cold climates. Allowance for wall height is a new factor proposed for NCC 2022 which affects thermal performance. A higher wall is less shaded by a given overhang than a wall with a lower height. Similar to the thermal bridging requirements for roofs, for walls, thermal bridging requirements for steel-framed dwellings can be met by either achieving minimum Total R-Values calculated in accordance with AS/NZS 4859.2 or by applying one of the thermal bridging mitigation options listed in the mitigation options tables. The thermal bridging mitigation requirements are distinct from the existing thermal break requirements of Clause 13.2.5(5).
13.2.6 Floors and subfloor walls	Proposed suspended floor insulation requirements are included in look-up tables showing subfloor wall height, whether reflective foil is installed under the floor and subfloor wall insulation. The most commonly used floor construction in Australia, as shown in CSIRO data, is waffle pod slab floors. It is the dominant floor construction in the cooler climates of Victoria and the ACT. In cooler climates, the use of a waffle pod slab instead of a concrete slab-on-ground will improve the NatHERS rating by around 0.4 stars. Hence, it is proposed to acknowledge the benefits of waffle pod slabs by requiring waffle pods in climate zone 6 to 8 under the DTS elemental provisions. The thermal bridging requirements for steel-framed walls can be met by either achieving total minimum R-Values calculated in accordance with AS/NZS 4859.2 or by applying one of the thermal bridging mitigation options listed in the tables.
Part 13.3 External glazing	The proposed external glazing, in general, uses the same structure and methodology as the current glazing provisions, but is modified to be better aligned with 7-stars NatHERS by introducing a set of new glazing factors: – level factor – bedroom factor – frame factor – floor surface factor – window openability. Winter and summer performance of glazing is calculated individually in the current requirements. The proposed new changes clearly separate winter and summer performance requirements. Winter and summer exposure factors are also updated to be better in line with 7-stars NatHERS.

NCC Reference	Changes and commentary
Part 13.5 Ceiling fans	The existing air movement requirements in NCC 2019 are redundant in the new provisions. The air movement requirements are restructured and are included in the proposed changes to the glazing and ceiling fan requirements. Instead of air movement requirements, minimum ceiling fan requirements are proposed for bedrooms and daytime habitable spaces in climate zones 1 to 3, and in daytime habitable spaces in climate zone 5.
Part 13.6 Whole-of-home energy usage	New Part proposed for NCC 2022 which requires the net equivalent energy usage of a building to not exceed a given allowance.
13.6.2 Net equivalent energy usage	Net equivalent energy usage is the overall energy usage of heating, cooling, heated water systems, and swimming pool and spa pumps (if applicable), minus installed capacity of PV. Various combinations of heating, cooling and heated water systems are included in the referenced whole-of-home energy efficiency factors Standard. The whole-of-home energy usage allowance for Class 1 dwellings is based on 70% of the benchmark appliances options (refer introduction). When calculating the net equivalent energy usage and the allowance, floor area adjustment factors account for different size of dwellings to provide a level playing field.

Source: ABCB.

A.2 Energy efficiency - Summary of changes to Volume One

The proposed changes to the energy efficiency provisions in Volume One of the NCC are set out in Table A.2.

Table A.2 Summary of proposed changes for energy efficiency for NCC Volume One 2022

NCC Reference	Changes and commentary
J1P2 (New building fabric of SOUs of a Class 2 building or a Class 4 part of a building) and J1P3 (Energy usage of SOUs of a Class 2 building or a Class 4 part)	These two new quantified Performance Requirements are specific to the SOUs of a Class 2 building or a Class 4 part of a building. They mirror the new quantified Performance Requirements proposed for Class 1 buildings in Volume Two in setting minimum standards for both the envelope of an SOU and the regulated equipment.

NCC Reference	Changes and commentary
J1P4 (New Performance Requirement: Renewable energy and electric vehicle charging)	This new Performance Requirement requires buildings to have features to support the ease of retrofit of PV, EV charging equipment and energy storage equipment. They are supported by a new set of DTS Provisions in Part J9.
J1V1 (formerly JV1 NABERS)	This expands the number of building classifications that can utilise the NABERS methodology to demonstrate compliance with Section J.
J1V2 (formerly JV2 Green Star)	This aligns the NCC with current Green Star modelling methodologies, and reduces conflicts between the Green Star and J1V3 modelling requirements.
J1V5 (New VURB for Class 2 buildings)	A new pathway specifically for Class 2 buildings (both common areas and SOUs). It is based on the verification using a reference building (VURB) pathway J1V3. Its intent is to allow for a single energy model for a Class 2 building to be used to demonstrate compliance.
Specification 34 (formerly JVb Modelling parameters for VURB)	Changes to clarify some modelling parameters used to define the energy use of buildings following the VURB pathway.
Part J3 (New elemental provisions for Class 2 building or a Class 4 part)	These new provisions provide a DTS Provisions for Class 2 SOUs or Class 4 parts of buildings. They are based on alignment with a 7-star NatHERS benchmark for an individual SOU. These provisions align closely to the proposed provisions for Class 1 buildings for envelopes and appliances, with the following key differences: 1. The whole-of-home energy use stringency is set to allow compliance with less (if any) reliance on the use of PV panels. 2. The minimum thermal resistance performance for walls includes an option to use a combined wall-glazing Total R-Value, in addition to one using an added material R-Value. 3. The only DTS pathway available for floors is for a concrete slab-on-ground.
J4D7 (formerly J1.6 Floors)	Sets the minimum thermal resistance level for floor constructions for the common area of a Class 2 building and Class 3 to 9 buildings. When developing NCC 2019, it was not considered cost beneficial to increase the minimum R-Value requirement from the NCC 2016 level. However, a change the methodology by which thermal resistance was calculated to better account for the impact of soil and sub-floor airspaces, as well as the impact of the building's geometry was recommended. This change introduced an unintended consequence for buildings with a low floor area to perimeter ratio, which would commonly require under slab insulation to comply via the DTS. This is difficult to justify given the reduction in energy costs does not offset the increased cost of the insulation. The exceptions are Class 3, Class 9c or a Class 9a ward area buildings in climate zone 7 and all buildings in climate zone 8, where the addition of insulation was found to be cost-effective.

NCC Reference	Changes and commentary
Part J9 (formerly J8 Energy monitoring and on-site distributed energy resources)	Updates include: 1. Clarifying electricity meters installed in buildings with a floor area greater than 2,500 m^2 for purposes of recording electricity consumption of an SOU are not required to provide sub-metering capability. 2. Expanding where sub-metering is required to include collecting the energy data related to the use of DER such as PV, EV and battery storage systems as part of the broader energy data consumption. 3. Introducing new provisions designed to make retrofit of DER equipment over the life of a building easier. These provisions require space to be left on electrical distribution boards for DER circuit breakers and for cable trays to connect distribution boards to car park spaces in Class 2 buildings. Class 2 buildings will also be required to install charge control devices to ensure EVs will only be charged when there is available electrical capacity in the building. Without this requirement, Class 2 buildings would be required to size their electricity supply to support 100% of car parking spaces being used to charge EV at times of peak demand. This would at least double the required electrical supply capacity for the building.
Specification 36 (formerly J1.2 material properties)	Specification 36 (previously Specification J1.2) provides thermal resistance values (R-Values) for commonly construction materials. It allows NCC users to calculate the thermal resistance of the building fabric when developing a DTS Solution for Part J4. An update is needed to Specification 36 because the airspace R-Values to align with AS/NZ 4859.2 (2018). The existing values in Specification 36 are based on an airgap average temperature of 10°C and temperature difference of 15°C between internal and external conditions. This does not reflect typical Australian conditions. AS/NZ 4859.2 (2018) uses a maximum temperature difference of 10°C. Updating the values by using the current AS/NZS 4859.2 (2018) method will remove the inconsistency between the Specification and Standard. Thermal properties for medium-weight autoclaved aerated concrete were also added.
B1P1 (A new allowance for the addition of PV)	This makes explicit that a notional allowance of 0.15 kPa should be included when designing roof structural systems in Class 7b warehouses. This allows for the installation of PV without jeopardising the structural integrity of a roof. Note, this requirement will not mean all roofs will be able to accommodate PV without modification. In some instances, the points of connection between roof sheets and trusses will need to be reinforced as part of the installation of PV panels.
Definition of a "reference building"	The thermal comfort requirement for buildings using the J1V1, J1V2 and J1V3 pathways is set at an absolute level (i.e. it must be ensured "in the proposed building, a thermal comfort level of between a Predicted Mean Vote of -1 to +1 is achieved across not less than 95% of the floor area of all occupied zones for not less than 98% of the annual hours of operation of the building"). However, the definition of a reference building in Schedule 3 reflects that the thermal comfort level of the proposed building need only be better than the reference building in order to comply. This definition creates ambiguity on how to meet the requirement. To reduce this ambiguity, it is proposed the reference to thermal comfort be removed from the definition.

Source: ABCB.

A.3 Condensation management

The proposed changes to the condensation management provisions in Volume One of the NCC are set out in Table A.3.

Table A.3 Summary of proposed changes for condensation management in NCC 2022

NCC Reference	Changes and commentary
NCC Volume One F8V1 NCC Volume Two H4V5	This Verification Method provides an optional pathway for demonstrating whether an external wall or roof complies with the condensation requirements. The major changes are: – New references to sections of the standard “AIRAH DA07” to provide further detail on input assumptions for use with the Verification Method. – New failure criteria for the analysis are included: “a mould index of greater than 3, as defined by Section 6 of AIRAH DA07”.
NCC Volume One F8D3(2) ABCB Housing Provisions 10.8.1(2)	Sarking-type materials and secondary insulation layers on the outside of primary insulation in an external wall are required to be vapour permeable in climate zones 4 to 8, where: – A minimum vapour permeance of 0.143 µg/N.s is specified in climate zones 4 and 5 (equivalent to a Class 3 or Class 4 Vapour Control Membrane as defined by AS 4200.1) – A minimum vapour permeance of 1.14 µg/N.s is specified in climate zones 6, 7 and 8 (equivalent to a Class 4 Vapour Control Membrane as defined by AS 4200.1)
NCC Volume One F8D3(2) ABCB Housing Provisions 10.8.1(2)	Sarking-type materials and secondary insulation layers on the outside of primary insulation in an external wall are required to be vapour permeable in climate zones 4 to 8, where: – A minimum vapour permeance of 0.143 µg/N.s is specified in climate zones 4 and 5 (equivalent to a Class 3 or Class 4 Vapour Control Membrane as defined by AS 4200.1) A minimum vapour permeance of 1.14 µg/N.s is specified in climate zones 6, 7 and 8 (equivalent to a Class 4 Vapour Control Membrane as defined by AS 4200.1)
NCC Volume One F6D4(2) ABCB Housing Provisions 10.8.2(2)	Exhaust from a kitchen, kitchen range hood, bathroom, sanitary compartment or laundry is required to be discharged outside of the building.
NCC Volume One F6D4(3) and NCC Volume One F6D4(4)	Where space for a clothes’ drying appliance is provided in accordance with Part F4D2, space must also be provided to duct from the clothes drying appliance to outdoor air. This requirement does not apply if a condensing clothes dryer is installed.
ABCB Housing Provisions 10.8.2(3).	Where a venting clothes dryer is installed, it must be discharged to outdoor air.
NCC Volume One F6D4(5)	Exhaust systems in bathrooms or sanitary compartments that that are not naturally ventilated (e.g. not provided with windows) are required to be interlocked with the room’s light switch and run for at least 10 minutes after the light switch is turned off.

NCC Reference	Changes and commentary
ABCB Housing Provisions 10.8.2(4)	
ABCB Housing Provisions 10.8.2(4)	To ensure the effective operation of exhaust systems, wet areas with exhaust systems that are not naturally ventilated are required to be provided with make-up air via a door undercut or in accordance with AS 1668.2.
ABCB Housing Provisions 10.8.2(6)	Rooms with venting clothes dryers that exhaust to outdoor air must be provided with make-up air in accordance with AS 1668.2.
NCC Volume One F8D4(6)	Where space for a clothes drying appliance is provided in accordance with Part F4D2, the room must also be provided with make-up air in accordance with AS 1668.2.
NCC Volume One F6D5 ABCB Housing Provisions 10.8.3	To provide an escape path for water vapour, roofs in climate zones 6, 7 and 8, except for concrete roofs, roofs made of structural insulated panes and roofs those that are subject to Bushfire Attack Level FZ, require a roof space with a height of at least 20 mm and evenly distributed ventilation openings. – The required total area of ventilation openings depend on the pitch of the roof and are not required in tiled roofs with a sufficiently permeable sarking (equivalent to a Class 4 Vapour Control Membrane as defined by AS 4200.1).
NCC Volume One J1V4 NCC Volume Two H6V3	This Verification Method provides an optional pathway for demonstrating compliance with the building sealing requirements of the energy efficiency sections of the NCC. The major changes are when a home is found to achieve an air change rate of less than 5 5 m2/m3/hr air changes per hour at 50 Pa reference pressure: – Continuous mechanical ventilation is required to be provided to the home. – Solid-fuel and gas combustion appliance are required to be provided with additional ventilation.
Schedule 3	A new defined term for “vapour permeance” is included, referencing the required method of assessing vapour permeance (the ASTM-E96 Water Method at 23 °C), the same test method required by the NCC reference document AS 4200.1. A new defined term for “primary insulation layer” is included, meaning the most interior layer of a wall or roof construction.

Source: ABCB.

B Summary of key areas of feedback on the CRIS

Provides a summary of the key areas of feedback on the CRIS in table form.

Table B.1 Summary of key areas of feedback on CRIS

Issue	Feedback received	Response
Problem statement and policy options		
Problem statement	The CRIS does not adequately identify and define the problem that the proposed regulations are seeking to address and there are other problems that the CRIS has not considered.	The problem statement chapter in the DRIS has been revised to include a discussion of the issues raised, particularly with respect to social equity, health and wellbeing, climate change and resilience of homes and the grid to weather extremes. In addition, the discussion of the policy response in the DRIS has been updated to reflect the changes in governments' policies, including noting that all Australian state and territory governments are now committed to net zero emissions by 2050 or earlier.
Policy options	Submissions suggested alternative policy options should be analysed in the CRIS.	The DRIS reflects the decisions made by the ABCB in respect to the design of the policy options analysed and includes commentary about other policy options explored but not analysed in the DRIS. These include: – adopting the Whole-of-Home (WoH) provisions only (with shell remaining at 6 stars) – setting a lower shell stringency (6.5 stars) for warmer climate zones (climate zone 2 and 3) – eliminating the lighting energy efficiency provisions from the NCC 2022.
Climate change and other impacts		
Impact of climate change	CSIRO's updated future climate files are not considered in the modelling.	The DRIS notes that: – while using future climate files may be beneficial, the ABCB has not been able to fully explore the impact of such a requirement, from either a technical or cost benefit perspective – depending on the year chosen for the analysis using these files may lead to perverse outcomes as designing for future climate will see a much greater reliance on strategies to reduce heating energy – Section J and the Class 1 Verification Using Reference Building (VURB) does not prohibit the use of future climate weather files if this is desired.

Issue	Feedback received	Response
	There is a need to build resilient buildings in response to the impacts of climate change.	Improving the resilience of buildings to future climate risks is the subject of a separate ABCB project. In response to a recommendation of the Royal Commission for National Natural Disaster Arrangements the ABCB is reviewing the adequacy of the NCC to address future extreme weather events and climate risks.
Non-market impacts	The CRIS does not adequately assess a number of non-market impacts (e.g. health and amenity, resilience and other social benefits).	The DRIS includes a more deliberative qualitative examination of the relevant non-market impacts raised during consultation.
Unintended consequences	A number of unintended consequences have not been included in the CRIS (e.g. added complexity, reduced consumer choice, reduced ventilation and increased condensation, increased fire risk, amenity loss, star rate creep, over-regulation).	These issues are explored further in the DRIS in a qualitative manner to reflect the feedback received during consultation
Approach to economic analysis		
Disaggregation of impacts	The impact of the shell and WoH provisions should be evaluated separately.	The DRIS now presents results by building classifications. The impact of the fabric improvements alone are analysed in a separate report by TIC. It is not possible to analyse the WoH requirements on their own as the analysis by EES already includes the improvements to building fabric.
Asymmetry in the treatment of costs and benefits	The benefits related to thermal bridging mitigation measures should be included if the cost of these measures is included	To ensure that the principle of symmetry is applied to the proposed thermal bridging mitigation provisions but the potential for double counting is recognised, the following modifications have been made to the RIS: – the benefits of thermal bridging measures have been included in the cost benefit analysis – the DRIS clearly states that the thermal bridging benefits were included in the 2009 6 star RIS, which had the effect of overstating the net impacts of that regulatory change.

Issue	Feedback received	Response
	Some stakeholders are of the view that the use of wholesale electricity prices rather than retail electricity prices undervalues the benefits	No change has been made to the approach taken in the CRIS. That is, the DRIS analysis continues to: – value the benefits associated with reductions in energy use at a household level based on retail energy prices – value benefits of the proposed provisions at an economy-wide or societal level using wholesale energy prices and avoided network investment. The use of wholesale energy prices as a proxy for the variable operating and maintenance costs (including fuel costs) that would otherwise be incurred to produce energy, in fact, overstates the costs that are avoided by society as a result of the changes to the NCC 2022 (i.e. the benefits are overstated).
	The avoided network benefits were underestimated in the CRIS by applying a conservation load factor (CLF) that was too high and applying the discount factors of 70% and an additional 10% in the case of Option A which are too high.	No change has been made to the approach taken in the CRIS as no evidence was provided by stakeholders as to an alternative value to use to quantify the avoided network investment.
	The reduction in wholesale electricity prices by 11% projected by the energy market modelling under Option A should be accounted for in the benefits.	The changes in wholesale electricity prices are a distributional benefit for all electricity customers rather than a societal benefit – any reduction in wholesale electricity prices is a benefit to electricity customers but a cost to generators, and any increase in wholesale electricity prices is a cost to electricity customers and a benefit to generators.
Cost estimation	Under/over estimation of costs. Biases have been introduced in the cost estimation through choices made on the technical modelling	In response to feedback provided during consultation: – TIC consulted with industry stakeholders to further explore their alternatives to the cost of compliance for the increased thermal performance requirements. For further information on some of TIC's findings, see Section 6.1.1 of the main report. – EES developed a revised optimisation approach for the WoH requirements which considers a much broader range of compliance options that are more representative of the likely industry responses to the regulation (including Improved modelling of

Issue	Feedback received	Response
		dwellings with no heating or cooling). Further information about the optimised approach can be found on Section 5.3.6 of the main report. The DRIS continues to assume that the most likely response of industry to the proposed thermal fabric changes would be to substantially maintain existing home sizes and designs (the exception being the reduction in window size assumed in TIC's thermal performance modelling).
	Industry will install what is the cheapest to meet the proposed new requirements	No change. The approach of selecting the lowest capital cost pathway to comply with the regulation has been maintained.
	A PV pathway should be considered for Class 2 buildings	No change. After further consideration of the technical evidence provided by TIC and EES it was concluded that exclusion of a PV pathway for high rise Class 2 dwellings appropriately reflects the likely response by industry given the costs of these solutions are likely to be significantly higher than for Class 1 dwellings.
	The DRIS should include increased construction costs due to supply chain disruptions from COVID-19	For completeness and to account for uncertainties in the compliance costs estimated, the DRIS includes additional sensitivity analysis showing the impact of increases in compliance costs on the Net Present Value (NPV) and Benefit Cost Ratio (BCR) of the proposal.
	Stakeholders have different views about the treatment of difficult and shaded blocks in the CRIS analysis. Some think that the costs associated with difficult and shaded blocks are underestimated and some think these costs are overestimated.	After reflecting on the feedback received about difficult blocks and further consideration of the approach taken to analyse these blocks in the CRIS, it has been concluded that the approach taken in the CRIS appropriately balances: – the existing evidence on the trends in block sizes and building approvals – the existing evidence on the marginal costs of building a 7 star home rather than a 6 star home on a difficult block – the uncertainties and complexities surrounding the characteristics and prevalence of these blocks.

Issue	Feedback received	Response

	Assuming zero learning rates for all costs (other than PV costs) is unreasonable. The RIS should factor expected technological improvements which would bring down the costs of equipment, materials and practices	After consideration of the feedback provided:
		– learning rates of rooftop solar PV continue to be included in the analysis
		– the following reductions were incorporated in the analysis for glazing costs based on feedback from the glazing industry
		  – 8 per cent over the first 5 years of the regulation
		  – 2 per cent over the last 5 years of the analysis timeframe
		– zero learning rates continue to be assumed for other costs
		– additional sensitivity analysis has been undertaken for compliance costs, which will account for the uncertainties in learning rates.

	Industry costs are underestimated	After consideration of the consultation feedback received around industry costs, the following changes have been made to the DRIS:
		– the following industry costs have been included in the analysis:
		  – redesign costs for volume builders
		  – transition costs for custom builders
		  – administrative costs for all buildings
		– wage assumptions used in the industry cost analysis are reviewed to reflect the feedback received during consultation and the most recent data.
		The potential impacts on downstream industries has not been included in the DRIS, as the CBA framework used in the analysis is a partial equilibrium approach that aims to capture the direct impacts associated with the proposed regulation. An assessment of the impacts of the proposed regulation on upstream and downstream industries would require the use of a general equilibrium framework.

Issue	Feedback received	Response
Treatment of refurbishments	Mixed feedback was received about the treatment of refurbishments with respect to the WoH provisions, with some stakeholders arguing that refurbishments should be exempt from the WoH provisions due to their complexities and others suggesting that it is practical to apply the WoH proposal to refurbishments as these can be achieved through solar PV.	No new information was received that could help overcome the complexities related to the analysis of the impacts of the proposed WoH on the refurbishment of existing buildings in the DRIS. Furthermore, at this stage it is still unclear if, and how, the proposed WoH requirements would apply to refurbishments in individual jurisdictions. Given this, refurbishments continue to be excluded from the impact analysis in the DRIS.
Specific inputs and assumptions		
Discount rate	Discount rate too high/low	No change. OBPR requires that a central discount rate of 7 per cent is used with sensitivity analysis provided at 3 per cent and 10 per cent. However, reflecting updating advice on valuation of long term environmental benefits, additional sensitivity analysis has been conducted to test the effect of a reduction on the central discount rate to 5.4 per cent from year 30 onwards.
Appliance replacement	The impact analysis should include multiple replacements of “like-for-like” equipment over the life of the building.	No change. The cost benefit analysis needs to account for impacts which are caused by the implementation of a regulation in comparison to the baseline. Future appliance decisions for affected households, which are outside the control of the NCC, will be made by the residents at some point in the future. It is a reasonable assumption that under the baseline scenario and in the policy scenarios, those households will have the same access to information, market options, and capital. Not including reinvestments in a like-for-like appliance does not preclude households from making that decision. Instead, it implicitly assumes that households will make the same decision in a policy and baseline scenario.

Issue	Feedback received	Response
Rebound effect	Mixed feedback received: – some stakeholders argue that energy efficiency will induce additional demand (i.e. a rebound effect of greater than 100 per cent) – others suggest there is no evidence for a rebound effect – some others argue that a rebound effect of any percentage implies a willingness-to-pay for an equivalent dollar amount of energy, which represents amenity for householders that should be included in the cost benefit analysis.	Reflecting stakeholder feedback that this amenity should be considered, the DRIS CBA modelling now includes an offsetting 10 per cent amenity benefit to match the rebound effect. The rebound effect will be maintained, as aside from any amenity value, it also decreases the carbon emissions saved and network effects of the induced demand.
Emissions factors	Several responses questioned the emissions intensity factors used in the modelling and noted that the Department of Infrastructure, Science, Energy and Resources (DISER) emissions intensity factors for electricity have changed since the time of the modelling.	The DRIS will used the latest emissions intensity estimates available, at the time of modelling the impacts.
Carbon price	The majority of stakeholders noted that the cost of carbon used in the analysis was too low, although several survey responses recommended an even lower cost of carbon than that used in the CRIS.	Recognising that market estimates are likely to underestimate the role of climate change and to address the feedback received during consultation, the DRIS modelling has been conducted using a social cost of carbon.

Issue	Feedback received	Response
PV penetration in the baseline	The average size of PV systems in new houses should be assumed to be 8.86 kW, not 5 kW.	Based on C4NET analysis for the ABCB, the assumed size of PV systems in new houses in 2019 has been updated in the DRIS analysis.
	The CRIS should assume that no incremental PV costs are incurred in at least 27 per cent of new houses which already have installed PV systems and that no incremental cost are incurred for any regulated load as the 8.86 kW PV system fully (or more than) offsets these loads.	No change. The methodology in the CRIS already recognises that there are a number of new dwellings built with solar PV under the baseline and that these dwellings may already have sufficient solar PV capacity installed to meet the proposed new requirements (and hence would not experience incremental costs with the introduction of the WoH requirements).
Electrification	The RIS should consider trends towards electrification.	No change. Consistent with best practice regulatory impact analysis, the baseline in the CRIS reflects announced policies. No state or territory has explicitly committed to phasing out natural gas.
STCs	The value of credits for Small-scale technology certificates (STCs) at the household level should be on an annual rather than average basis.	EES has changed the assumption in its model to reflect annual rather average credits. This change flows through the household analysis in the DRIS.

Source: ACIL Allen.

C Rebound effect studies

This appendix provides a summary of studies into the size and nature of the rebound effect.

Table C.1 Studies into the size and nature of the rebound effect

Market segment	Study	Region	Estimated rebound	Notes	Reference
Passenger vehicles	ECA	Developed countries	9–30%, median of 20%		Economic Consulting Associates. 2014. Phase 1 final report: the rebound effect for developing countries. http://www.eviAdenceondemand.info/phase-1-final-report-the-rebound-effect-for-developing-countries
	ECA	Developing countries	28–43%, median of 35%		Economic Consulting Associates. 2014. Phase 1 final report: the rebound effect for developing countries. http://www.evidenceondemand.info/phase-1-final-report-the-rebound-effect-for-developing-countries
	Gillingham et al.	Developed countries	4.5–46%, median of 15.5%	These are based on elasticities and they caution that “recent evidence suggests that consumers may respond comparatively less to changes in energy efficiency than to changes in fuel price.”	Gillingham, Kenneth, David Rapson, and Gernot Wagner. “The rebound effect and energy efficiency policy.” Review of environmental economics and policy 10(1):68-88. http://reep.oxfordjournals.org.virtual.anu.edu.au/content/10/1/68.full
	Gillingham et al.	Developing countries	7.5–62 %, median of 21%		Gillingham, Kenneth, David Rapson, and Gernot Wagner. “The rebound effect and energy efficiency policy.” Review of environmental economics and policy 10(1):68-88. http://reep.oxfordjournals.org.virtual.anu.edu.au/content/10/1/68.full
	Hughes et al.	USA	21–34 % over 1975–1980, 4.2 % over 2000–2009		Hughes J, Knittel C, Sperling D. Evidence of a shift in the short-run price elasticity of gasoline demand. Energy J. 2008;29(1):93–114.

Market segment	Study	Region	Estimated rebound	Notes	Reference
	Small and Van Dender	USA	22.6 % over 1966–2001; 10.7 % over the 1997–2001		Small K and Van Dender K. “Fuel efficiency and motor vehicle travel: the declining rebound effect.” 2007. Irine, CA, University of California. http://www.economics.uci.edu/files/docs/workingpapers/2005-06/Small-03.pdf. A slightly earlier version was published in Energy Journal (28)1: 25–51.
	Small and Hymel	USA	4.2% over 2000–2009	For their preferred asymmetric model	Small K and Hymel Kent. “The rebound effect from fuel efficiency standards: measurement and projection to 2035.” Prepared for U.S. EPA, Washington, DC. 2011. https://www3.epa.gov/otaq/climate/documents/mte/420r15012.pdf.
Residential space	O’Leary	Australia	5 -10%	Suggests than the rebound effect for efficiency alone should be nearer the low end of estimates or around 5 per cent to 10 per cent to expected energy savings.	O’Leary, Timothy 2016, *Industry adaption to NatHERS 6 star energy regulations and energy performance disclosure models for housing*, December, https://minerva-access.unimelb.edu.au/bitstream/handle/11343/220478/Tim%20Oleary%20final%20with%20corrections.pdf?sequence=1&isAllowed=y.
	ACG	Australia	30%	Modelling done by Tony Isaacs and Robert Foster for a 2011 Mandatory Disclosure RIS included a 30 per cent rebound effect.	Allen Consulting Group (ACG) 2011, *Mandatory Disclosure of Residential Building Energy, Greenhouse and Water Performance: Consultation Regulation Impact Statement*, report to the National Framework for Energy Efficiency Building Implementation Committee, March.
	McKinsey	USA	15- 30%		McKinsey & Company 2009, *Unlocking Energy Efficiency in the U.S*. Economy, https://www.sallan.org/pdf-docs/MCKINSEY_US_energy_efficiency.pdf.

Market segment	Study	Region	Estimated rebound	Notes	Reference
	ECA	High-income countries	12–56%, median of 30%		Economic Consulting Associates. 2014. Phase 1 final report: the rebound effect for developing countries. http://www.evidenceondemand.info/phase-1-final-report-the-rebound-effect-for-developing-countries
	Greening et al.	Same as above	10–30%		Greening L, Greene D, Difiglio C. Energy efficiency and consumption—the rebound effect—a survey. Energy Policy. 2000;28:389–401.
	Sorrell	Same as above	10–30%		Sorrell S, Dimitropoulos J, Somerville M. Empirical estimates of the direct rebound effect: a review. Energy Policy. 2009;37:1356–71.
	Nadel	USA	1–12%	Raises questions about studies claiming higher rebound in the USA	Nadel S. "The rebound effect: large or small? 2012. American Council for an Energy-Efficient Economy, Washington, DC. http://aceee.org/white-paper/rebound-effect-large-or-small.
Other residential	Davis	USA	6%	For clothes washers	Davis L. Durable goods and residential demand for energy and water: evidence from a field trial. RAND J Econ. 2008;39(2):530–46.
	Davis et al.	Mexico	Savings from high-efficiency refrigerators less than expected and high-efficiency air conditioners increased energy use		Davis L, Fuchs A, Gertler P. Cash for coolers: evaluating a large-scale appliance replacement program in Mexico. Am Econ J Econ Pol. 2015;6(4):207–38. http://www-wds.worldbank.org/external/default/WDSContentServer/WDSP/IB/2014/12/05/000442464_20141205134555/Rendered/PDF/929360JRN0240A00Box385297B00PUBLIC0.pdf.

Market segment	Study	Region	Estimated rebound	Notes	Reference
	Nadel	USA	5–12% for lighting, 5% for clothes washers, 1–13% for air conditioning and little evidence of rebound for water heating		Nadel S. "The rebound effect: large or small? 2012. American Council for an Energy-Efficient Economy, Washington, DC. http://aceee.org/white-paper/rebound-effect-large-or-small.
Commercial and industrial	ECA	High-income countries	0–19%, median of 4%		Economic Consulting Associates. 2014. Phase 1 final report: the rebound effect for developing countries. http://www.evidenceondemand.info/phase-1-final-report-the-rebound-effect-for-developing-countries.
	Gillingham et al.	3 US states	9–12%, median of 10%	These are elasticities for electricity and include residential as well as C&I	Gillingham, Kenneth, David Rapson, and Gernot Wagner. "The rebound effect and energy efficiency policy." Review of environmental economics and policy 10(1):68-88.
	Gillingham et al.	Developing countries	2–40%, median of 13%	These are elasticities for electricity and include residential as well as C&I	Gillingham, Kenneth, David Rapson, and Gernot Wagner. "The rebound effect and energy efficiency policy." Review of environmental economics and policy 10(1):68-88.

Market segment	Study	Region	Estimated rebound	Notes	Reference
Various	IEA	Various	0-65%, estimates tend to converge between 10% and 30%	Direct rebound effects can range from 0% (e.g. in whiteware) to as much as 65% (e.g. electrically heated homes in California) (Hertwich, 2005). However, estimates tend to converge between 10% and 30%. This IEA report also refers to a total macroeconomic rebound effect in the range of 10 per cent to 30 per cent in the UK and suggests the rate is similar in other developed countries and higher in developing countries.	International Energy Agency (IEA) 2015, *Capturing the Multiple Benefits of Energy Efficiency*, November, https://webstore.iea.org/capturing-the-multiple-benefits-of-energy-efficiency, accessed 2 March 2021.

Source: Nadel, S. The Potential for Additional Energy Efficiency Savings Including How the Rebound Effect Could Affect This Potential. Curr Sustainable Renewable Energy Rep 3, 35–41 (2016); O'Leary, Timothy 2016, *Industry adaption to NatHERS 6 star energy regulations and energy performance disclosure models for housing*, December; ACG 2011, *Mandatory Disclosure of Residential Building Energy, Greenhouse and Water Performance: Consultation Regulation Impact Statement;* IEA 2015, *Capturing the Multiple Benefits of Energy Efficiency;* McKinsey & Company 2009, *Unlocking Energy Efficiency in the U.S*. Economy.

D Comparison of Renew and CRIS modelling

As noted in the body of the report, Renew undertook their own modelling of the proposed NCC changes. This appendix provides a short summary of how Renew's modelling differs to the modelling in the CRIS.

The two analyses produce significantly different results as some of the key inputs used in the analyses are fundamentally different.

The key differences between the two analyses are summarised in Table D.1, with the more significant differences described in further detail in the following sections.

Table D.1 Key differences between the analyses undertaken to inform the Renew submission and the NCC 2022 RIS

	Renew Analysis	NCC 2022 CRIS
Purpose of the analysis	To 'test the impact [on households] of better energy performance'[2] and 'demonstrate the costs and benefits of consumer choices within the parameters of the legal minimum standards'[3].	To inform a regulatory change (change to the NCC 2022) and meet the requirements under the Regulatory Impact Analysis Guide for Ministers' Meetings and National Standard Setting Bodies.
Level of analysis	Household	Economy-wide, with household level analysis to demonstrate distributional impacts.
Policy design	Analyses five policy scenarios (plus the baseline) with dwelling and equipment configurations that would deliver results close to, or even exceeding, a zero net societal cost outcome.	The analysis in the CRIS is based on achieving two targets equivalent to: – the societal cost of a 7 star dwelling with benchmark equipment and no PV (Option B in the CRIS) 70% of the societal cost of the above option (Option A in the CRIS).

[2] Renew 2021, *Households Better Off: Lowering energy bills with the 2022 National Construction Code*, August, p. 2.

[3] Ibid, p. 12

	Renew Analysis	NCC 2022 CRIS
Assumed industry response to the regulation	Most cost effective pathway (one which incurs higher initial capital costs but higher longer term benefits).	Lowest cost pathway (one which incurs the lowest initial capital costs to meet the regulation). This approach is consistent with the overall feedback received from stakeholders on the CRIS and with the information and split incentives problems identified in the CRIS.
Costs		
Additional costs included	Nil	Costs included to address thermal bridging issue in steel-framed buildings and costs related to meeting the 7 star standard in small and narrow (difficult) blocks. Note that the benefits of thermal bridging measures have been included in the cost benefit analysis in the DRIS.
Appliance costs	The appliance costs assumed by Renew are broadly consistent with those assumed in the CRIS analysis. One significant exception is the cost of ducted gas heating which is significantly higher than the price used in the CRIS for comparable systems. Both the CRIS and Renew's price for this item is based on market research.	
Benefits		
Value of energy savings	Energy savings valued at retail energy prices, sourced from major retailers in each of the studied locations. These prices were held constant over time.	Energy savings for economy-wide analysis valued at wholesale energy prices (as a proxy for avoided generation resource costs), using projections from specialist energy modelling, and avoided network investment. Savings for household analysis based on retail price projections. There are some notable differences between the retail prices used in the CRIS and those used in the analysis by Renew, which are discussed further below.

	Renew Analysis	NCC 2022 CRIS
Rebound effect	Nil	Assumed to be 10 per cent (which reduces the benefits), with sensitivity analysis at different rebound factors. Reflecting stakeholder feedback that the amenity associated with the rebound effect should be considered, the DRIS modelling includes an offsetting 10 per cent amenity benefit to match the rebound effect. The rebound effect has been maintained, as aside from any amenity value, it also decreases the carbon emissions saved and network effects of the induced demand.
Thermal load assumptions	Heating and cooling loads calculated using the Sunulator model. Energy use is based on NatHERS star bands.	Heating and cooling energy savings are based on hourly simulation using a weighted average of an all-day and workday occupancy which assumes that heating and cooling is only used when internal conditions are uncomfortable.
CBA parameters		
Discount rate	2 per cent	7 per cent. This consistent with guidance from the Office of Best Practice Regulation (OBPR) on Australian Government regulatory impact analysis.
Timeframe for evaluation of benefits	20 years	At the economy-wide level, the CRIS evaluates ten years of new builds. The duration of the benefits for each of these cohorts (the life of benefits) vary depending on the life of the assets installed to meet the regulation. Investments relating to: – heating, cooling and thermal shell are assumed to have a life of 30 years – water heating equipment are assumed to have a lifespan of 12 years – solar panels are assumed to have a lifetime of 20 years and inverters are assumed to last 10 years. It is also assumed that inverters are replaced in year 11. At the household level, the CRIS evaluates the impacts of a dwelling built in 2022 which receives benefits for as long as the life of the assets installed (based on the same assumptions above).

Source: TIC, EES and ACIL Allen

Each of these differences compound to increase the net benefits calculated in Renew's submission, compared to the household results in the NCC 2022 CRIS.

D.1 Policy design

Renew analyses five policy scenarios (plus the baseline) with dwelling and equipment configurations that would deliver results close to, or even exceeding, a zero net societal cost outcome. The characteristics of these scenarios are summarised in Table D.2.

Table D.2 Characteristics of scenarios modelled by Renew

	Scenario 1 (baseline)	Scenario 2 (7 stars)	Scenario 3 (7 stars + WoH)	Scenario 4 (7 stars + WoH)	Scenario 5 (7 stars + WoH)	Scenario 6 (7.5 stars + WoH)
Description	6-Star dual fuel	7-Star dual fuel	7-Star dual fuel (basic energy budget)	7-Star dual fuel (strong energy budget)	7-Star all-electric	7.5-Star all-electric
NatHERS rating	6	7	7	7	7	7.5
Hot water	Gas instantaneous	Gas instantaneous	Gas instantaneous	Gas instantaneous	Heat pump	Heat pump
Heating	Gas [a]	Gas [a]	Gas [a]	Gas [a]	Heat pump	Heat pump
Cooling	Evaporative	Evaporative	Heat pump (3 star)	Heat pump (5.5 star)	Heat pump (5.5 star)	Heat pump (5.5 star)
Cooking	Gas	Gas	Gas	Gas	Induction	Induction
Other appliances	Electric	Electric	Electric	Electric	Electric	Electric
Solar	None	None	3.5 kW	6.6 kW	6.6 kW	6.6 kW

[a] Fixed gas furnace heating assumed in Hobart, Sydney and Perth. Ducted gas heating assumed in Melbourne.

Source: Renew 2021, Households Better Off: Lowering energy bills with the 2022 National Construction Code, August.

As shown in Table D.2, the equipment used under the WoH scenarios is relatively high efficiency and this is then combined with either 3.5kW or alternatively 6.6 kW of PV in all cases. Scenario 6 also includes an increase to 7.5 stars.

The design of Renew's scenarios means that their analysis is not based on the same targets as those analysed by the CRIS, which are equivalent to:

— the societal cost of a 7 star dwelling with benchmark equipment and no solar PV (Option B in the CRIS), or

— 70 per cent of the societal cost of the above option (Option A in the CRIS).

The technical analysis underpinning the CRIS showed that, in many cases, a dwelling with reasonably efficient equipment can meet the performance requirements of Option B without the need for any solar PV. In the case of Option A, it was also shown that in some cases, depending on equipment selection, it is possible to achieve compliance without the use of PV and that, where PV is required, it is in most cases a very modest requirement (almost always less than 3 kW for an average sized dwelling).

D.2 Assumed industry response to the regulation

By assuming higher levels of PV would be installed than the minimum required to meet the proposed performance requirements in NCC 2022, Renew's analysis inherently assumes a different industry response to the regulation than that in the CRIS analysis.

The CRIS analysis assumes that the most likely response to the NCC 2022 will be to adopt the lowest cost upgrade pathway, while Renew's analysis, by assuming higher levels of PV would be installed in every case, has adopted a cost effective pathway which results in higher initial capital outlays but improved outcomes in the long term (and hence improved benefit cost ratios compared to the CRIS).

The CRIS approach is consistent with the overall feedback received from stakeholders and with the information and split incentives problems identified in the CRIS.

D.3 Appliance costs

Most of the appliance costs assumed by Renew are broadly consistent with the appliance costs assumed in the CRIS, except for the cost of ducted gas heating (costed in Renew's analysis at $9,000). Feedback from the ABCB's technical consultants suggest that this value appears too high, noting that the cost for a unit sized to service a 200 m2 dwelling (about 15-18kW for a 7 star rated dwelling) is about half the cost assumed in Renew's analysis. Furthermore, this cost appears to be higher than for a comparable reverse cycle ducted system. If this were the case, switching from gas heating to heat pump heating would be extremely cost effective (no increase in capital cost), and would typically offer lower running costs and permit greater use of PV generation on-site. On this basis, some of the benefits of the all-electric options put forward by Renew's analysis may be overstated.

D.4 Value of energy savings

As Renew's analysis has been undertaken at the household level, the energy savings are valued based on retail electricity prices.

The analysis in the NCC 2022 CRIS has been undertaken at an economy-wide level, with the energy savings valued using avoided resource costs, and at the household level, with the energy savings valued using retail electricity prices.

The economy-wide level analysis in the NCC 2022 CRIS values the energy savings based on wholesale electricity prices, as a proxy for avoided generation resource costs, and avoided network investment. Wholesale electricity prices are around 25-30 per cent of the retail electricity prices, which results in much lower benefits than if retail electricity prices are used.

In addition, the retail energy prices used in the Renew analysis were based on direct information provided by major retail providers in each location (Renew researched three retail tariff offers from major energy retailers and used the average of these three offers in their modelling), while the retail energy prices used to analyse the distributional impacts for the CRIS are based on different sources as follows:

— electricity prices are based on AEMC's 2020 report on retail electricity price trends for the start year and projected over time using information sourced from our proprietary model *PowerMark* on the change in the wholesale electricity cost component and assumed the remaining components of the retail electricity price remain constant in real terms

— gas prices for the start year are sourced from EES's Whole-of-Home Report for the NCC 2022[4] and projected over time using information sourced from our model *GasMark*

— feed in tariffs were estimated/projected using the average of the annual large-scale solar dispatch weighted wholesale electricity price in each jurisdiction plus 6 per cent, which represents loss factors that the retailer will pass onto the end consumer.

As highlighted in the following table, some prices are significantly different between the two analysis. Most notably:

— The feed-in tariffs are consistently higher in Renew's analysis relative to the CRIS, and as mentioned before, this value is kept constant over time. There have been significant changes in feed-in tariffs over the last few years. For example, the Victorian feed-in tariff has reduced from 12 cents per kWh in 2019-20 to 10.2 cents in 2020-21 and 6.7 cents in 2021-22 (including the social cost of carbon). The draft decision for 2022-23 is to reduce this to 5.2 cents per kWh (including the social cost of carbon). The use of higher feed-in tariffs improves the cost effectiveness of PV installations in the Renew analysis relative to the CRIS.

  The electricity tariffs used in the CRIS are generally higher than those in Renew's analysis. The AEMC tariffs used in the CRIS prorate the daily (fixed) charges into variable charges, while Renew calculates supply charges separately. These fixed charges will be excluded from the tariffs used in the DRIS.

[4] Which EES determined by reviewing the range of offerings from a range of energy companies – except for Western Australia where prices are regulated and hence reference was made to the relevant WA government website.

Table D.3 Comparison of retail energy prices

	Renew Analysis	NCC 2022 CRIS (2022)	Variance
Electricity (c/kWh)			
Tasmania	22	23.4	1.4
Victoria	19.8	24.3	4.5
NSW	30.4	28.9	-1.5
WA	29.3	30.3	1.0
Gas (c/MJ)			
Tasmania	4	3.7	-0.3
Victoria	2.2	2.4	0.2
NSW	2.4	3.4	1.0
WA	4.1	4	-0.1
Feed-in tariff (c/kWh)			
Tasmania	8	2.5	-5.5
Victoria	8	2.5 (DRIS includes an additional 2.5 cents for the social cost of carbon)	-5.5
NSW	7	3	-4.0
WA	7	7	-

Source: AEMC, Residential Electricity Price Trends 2020, Final report, 21 December 2020; EES 2021, NCC 2022 Update - Whole-of-Home Component, Draft Report, May; Renew 2021, Households Better Off: Lowering energy bills with the 2022 National Construction Code, August.

E Climate change impacts included in SCC estimates

This appendix summarises the climate change damages highlighted by the Intergovernmental Panel on Climate Change (IPCC) and the damages that are included in the latest Social Cost of Carbon (SCC) estimates by the United States (US) Government's Interagency Working Group (IWG) on Social Cost of Greenhouse Gases.

Table E.1 IPCC Climate Impacts in the IWG SCC Estimates

Damage Type	Sector	Included/excluded in the IWG SCC Estimates	Impact
Economic	Agriculture	Included	Impacts on average crop yields due to average temperature increases and CO_2 fertilization effect *Models are more optimistic than current observations, potentially due to optimistic assumptions about CO_2 fertilization effect*
		Excluded	Increases in yield variability
		Excluded	Change in food quality, including nutrition content
		Excluded	Increased pest and disease damage
		Excluded	Flood and sea level impacts on food infrastructure and farmland
		Excluded	Food security
		Excluded	Food price stability and price spikes
	Forestry	Included	CO_2 fertilization
		Included	Shifting geographic range
		Excluded	Increased pest and disease damage
		Excluded	Increasing risk of wildfire
	Fresh water availability	Included	Changing precipitation
		Excluded	Melting snowpack
		Excluded	Changing water quality

Damage Type	Sector	Included/excluded in the IWG SCC Estimates	Impact
		Excluded	Competing uses, including overexploitation of groundwater resources
		Excluded	Water security and water prices
		Partially Included	Water supply system losses and disruptions *While general infrastructure costs of coastal extreme events (flooding and storms) are included, inland extreme events are omitted. Also, integrated assessment models (IAMs) exclude more long-term costs from these infrastructure losses, including human suffering.*
	Fisheries and aquatic tourism	Excluded	Shifted geographic ranges, seasonal activities, migration patterns, abundances, and species interactions
		Excluded	Reduced growth and survival of shellfish and other calcifiers
		Excluded	Coral bleaching
		Excluded	Decrease in catch potential at some latitudes
	Energy	Partially Included	Energy system losses and disruptions *While general infrastructure costs of coastal extreme events (flooding and storms) are included, inland extreme events are omitted. Also, IAMs exclude more long-term costs from these infrastructure losses, including human suffering and increases in energy prices.*
	Property and infrastructure loss	Included	Coastal property losses due to storms, flooding, and sea level rise
		Excluded	Inland property loss due to extreme weather events, including flooding
		Excluded	Melting permafrost
		Excluded	Wildfires

Damage Type	Sector	Included/excluded in the IWG SCC Estimates	Impact
	Declining economic growth	Excluded	Labour productivity
		Excluded	Prolonging and creating new types of poverty traps
		Excluded	Diverted R&D funds for adaptation research
		Excluded	Lost land, capital, and infrastructure
Non-market	Human health *Cardiovascular, respiratory disorders, diarrhea, and morbidity for some health impacts are included in FUND [c], and thus partially included in PAGE [b]*	Included	Coastal mortality from flooding and storms
		Included	Spread in geographic range of vector-borne diseases *Significant diseases are included, though Lyme disease is excluded*
		Excluded	Wildfires
		Excluded	Mortality from inland extreme weather events
		Excluded	Food and water availability
		Partially Included	Heat related deaths
		Partially Included	Water-borne diseases
		Partially Included	Morbidity: non-fatal illness and injury
		Partially Included	Air quality *Air quality is included in DICE [a], though it does not account for changes due to pollen or wildfire*
		Included	Shifted geographic ranges, seasonal activities, migration patterns, abundances, and species interactions

Damage Type	Sector	Included/excluded in the IWG SCC Estimates	Impact
	Terrestrial, freshwater, and marine ecosystems and wildlife		*The value of ecosystems and biodiversity are included in general terms, not specific to any one damage*
		Included	Extinction and biodiversity loss
		Excluded	Non-climate stressors: habitat modification, over-exploitation, pollution, and invasive species
		Excluded	Abrupt and irreversible regional-scale change in the composition, structure, and function of ecosystems *Environmental tipping points in non-climate systems are excluded*
		Excluded	Effects of ocean acidification on polar ecosystems and coral reefs *Ocean acidification is excluded*
		Partially Included	Loss of habitat to sea level rise *Wetland loss explicitly modelled in FUND [c], and thus partially in PAGE [b]*
Social	Migration	Excluded	Increased displacement *FUND [c] partially accounts for migration, but uses arbitrary measurements of resettlement and costs*
	Social and political instability	Excluded	Violence, civil war, and inter-group conflict
		Excluded	National Security
Non-climate stressors	Non-climate stressors	Excluded	Climate-related hazards exacerbate other stressors
	Multidimensional inequalities	Excluded	Inequalities, including income

Damage Type	Sector	Included/excluded in the IWG SCC Estimates	Impact
	Violent conflict	Excluded	Violent conflict increases vulnerability
Tipping points [d]	Climate tipping points *Known tipping points are modelled as a single event, instead of multiple events. Furthermore, fat tails* [e]*, which capture unknown tipping points, are excluded*	Partially Included	Reduction in terrestrial carbon sink
		Partially Included	Boreal tipping point
		Partially Included	Amazon tipping point
		Partially Included	Other tipping points
	Ecosystem tipping points	Excluded	Abrupt and irreversible regional-scale change in the composition, structure, and function of ecosystems *Environmental tipping points in non-climate systems are excluded*

[a] The DICE (Dynamic Integrated Climate and Economy) model by William Nordhaus evolved from a series of energy models and was first presented in 1990.
[b] The PAGE (Policy Analysis of the Greenhouse Effect) model was developed by Chris Hope in 1991 for use by European decision-makers in assessing the marginal impact of carbon emissions.
[c] The FUND (Climate Framework for Uncertainty, Negotiation, and Distribution) model, developed by Richard Tol in the early 1990s, originally to study international capital transfers in climate policy was widely used to study climate impacts.
[d] Tipping points (also known as discontinuities) are broadly defined as a threshold beyond which a small change in conditions causes rapid, often irreversible changes in ecosystem characteristics.
[e] Fat tails refer to the upper ends (the right sides) of the probability density functions of a range of climate change-related variables. Tail fatness is an indicator of how quickly the probability of an event declines relative to the severity of that event, with fatter tails corresponding to lower rates of decline.
Note: IAMs stand for *Integrated Assessment Models.*
Source: Institute for Policy Integrity 2019, A Lower Bound: Why the Social Cost of Carbon Does Not Capture Critical Climate Damages and What That Means for Policymakers, February, https://policyintegrity.org/files/publications/Lower_Bound_Issue_Brief.pdf, accessed 23 May 2022.

F Upgrade costs for individual dwellings

This Appendix provides details of the estimated marginal costs of compliance with NCC 2022 under each of the upgrade pathways outlined in Chapter 5, for each of the climate zones and jurisdictions modelled by EES. The estimates presented in the tables in this Appendix include:

— all costs incurred at the time of construction, except the additional costs incurred by difficult blocks and the cost of replacement of solar PV inverters after ten years

— the estimated reductions in the costs of space conditioning equipment due to the improved thermal shell (only incurred by dwellings that are 6 stars in the BAU)

— the estimated costs of mitigating thermal bridging in steel frame buildings

— the 10 per cent discount in retail costs discussed in Section 5.4.1 as a proxy to estimate the resource cost of the changes in construction.

F.1 Cost for Class 1 dwellings

This section presents the cost tables for Class 1 dwellings.

Table F.1 Estimated marginal construction costs under Option A — upgrade pathway for Class 1 dwellings with no PV and 6 stars in the BAU (lowest cost upgrade pathway of alternative response options analysed), $/dwelling

Jurisdiction	NCC climate	Shell	Solar PV[a]	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	2	706	3,383	-240	73	-145	3,776
NSW	4	372	3,383	-240	72	-145	3,442
NSW	5	1,308	3,383	-240	73	-145	4,379
NSW	6	210	3,780	-240	71	-145	3,676
NSW	7	754	3,409	-237	123	-145	3,904
NSW	8	492	4,472	-198	56	-145	4,677
VIC	4	1,266	2,171	-906	218	-364	2,386
VIC	6	1,038	2,660	-467	47	-364	2,915
VIC	7	1,637	2,659	-467	47	-364	3,513
VIC	8	1,060	5,211	-739	0	-364	5,167

Jurisdiction	NCC climate	Shell	Solar PV[a]	Heating and cooling	Hot water	Plant savings (offset)	Total
QLD	1	283	79	-144	1,366	-142	1,441
QLD	2	562	79	-144	586	-142	942
QLD	3	172	79	-144	1,366	-142	1,331
QLD	5	1,041	79	-144	1,375	-142	2,210
SA	4	1,143	1,160	-633	521	-232	1,959
SA	5	1,129	1,160	-632	248	-232	1,673
SA	6	899	2,407	-613	210	-232	2,671
WA	1	517	752	-786	348	-166	666
WA	3	524	752	-786	348	-166	673
WA	4	1,128	675	-784	288	-166	1,142
WA	5	959	676	-784	288	-166	973
WA	6	884	1,226	-768	285	-166	1,460
TAS	7	1,621	1,359	-225	897	-211	3,442
NT	1	1,486	7,790	-91	1	-141	9,045
NT	3	1,288	435	-127	400	-141	1,854
ACT	7	321	777	-197	525	-236	1,191

[a] Includes the cost of solar panels and inverter (for the first year only). As noted in Chapter 5, inverters are assumed to be replaced in year 11, the cost of this second inverter is not included in this table.

Note: Negative numbers reflect savings in construction costs. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table F.2 Estimated marginal construction costs under Option B — upgrade pathway for Class 1 dwellings with no PV and 6 stars in the BAU (lowest cost upgrade pathway of two alternative response options analysed), $/dwelling

Jurisdiction	NCC climate	Shell	Solar PV[a]	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	2	706	622	-155	33	-145	1,062
NSW	4	372	686	-155	34	-145	792
NSW	5	1,308	686	-155	34	-145	1,728
NSW	6	210	718	-155	34	-145	663
NSW	7	754	718	-155	35	-145	1,207
NSW	8	492	3,321	-151	60	-145	3,577
VIC	4	1,266	70	-628	612	-364	956
VIC	6	1,038	479	-496	491	-364	1,148
VIC	7	1,637	72	-496	632	-364	1,481
VIC	8	1,060	1,018	-33	433	-364	2,114
QLD	1	283	12	-92	6	-142	67
QLD	2	562	16	-141	2	-142	297
QLD	3	172	12	-142	2	-142	-98
QLD	5	1,041	18	-141	2	-142	778
SA	4	1,143	84	-510	82	-232	566
SA	5	1,129	84	-510	82	-232	552
SA	6	899	134	-505	97	-232	393
WA	1	517	68	-354	248	-166	314
WA	3	524	68	-354	248	-166	320
WA	4	1,128	112	-746	200	-166	528
WA	5	959	112	-746	200	-166	359
WA	6	884	628	-736	269	-166	879
TAS	7	1,621	160	-195	267	-211	1,642
NT	1	1,486	2	-103	212	-141	1,456
NT	3	1,288	2	-127	204	-141	1,225
ACT	7	321	96	-70	242	-236	354

[a] Includes the cost of solar panels and inverter (for the first year only). As noted in Chapter 5, inverters are assumed to be replaced in year 11, the cost of this second inverter is not included in this table.

Note: Negative numbers reflect savings in construction costs. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table F.3 Estimated marginal construction costs under Option A — upgrade pathway for Class 1 dwellings with no PV and 7 stars in the BAU (lowest cost upgrade pathway of alternative response options analysed), $/dwelling

Jurisdiction	NCC climate	Shell	Solar PV[a]	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	2	191	3,383	-110	73	0	3,536
NSW	4	212	3,383	-110	72	0	3,557
NSW	5	210	3,383	-110	73	0	3,556
NSW	6	210	3,780	-110	71	0	3,951
NSW	7	110	3,409	-107	123	0	3,535
NSW	8	N/A	N/A	N/A	N/A	N/A	N/A
VIC	4	151	2,171	-579	218	0	1,962
VIC	6	150	2,660	-139	47	0	2,719
VIC	7	79	2,659	-139	47	0	2,646
VIC	8	N/A	N/A	N/A	N/A	N/A	N/A
QLD	1	283	79	-16	1,366	0	1,712
QLD	2	245	79	-16	586	0	895
QLD	3	172	79	-16	1,366	0	1,601
QLD	5	270	79	-16	1,375	0	1,709
SA	4	197	1,160	-424	521	0	1,453
SA	5	102	1,160	-423	248	0	1,087
SA	6	195	2,407	-404	210	0	2,408
WA	1	189	752	-637	348	0	652
WA	3	114	752	-637	348	0	578
WA	4	182	675	-635	288	0	510
WA	5	95	676	-635	288	0	424
WA	6	180	1,226	-619	285	0	1,072
TAS	7	0	1,359	-35	897	0	2,221
NT	1	801	7,790	36	1	0	8,628
NT	3	801	435	0	400	0	1,637
ACT	7	0	777	16	525	0	1,318

[a] Includes the cost of solar panels and inverter (for the first year only). As noted in Chapter 5, inverters are assumed to be replaced in year 11, the cost of this second inverter is not included in this table.

Note: Negative numbers reflect savings in construction costs. Plant savings offsets only applicable to buildings that are 6 stars in the BAU. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table F.4 Estimated marginal construction costs under Option B — upgrade pathway for Class 1 dwellings with no PV and 7 stars in the BAU (lowest cost upgrade pathway of alternative response options analysed), $/dwelling

Jurisdiction	NCC climate	Shell	Solar PV[a]	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	2	191	622	-25	33	0	821
NSW	4	212	686	-25	34	0	907
NSW	5	210	686	-25	34	0	905
NSW	6	210	718	-25	34	0	938
NSW	7	110	718	-25	35	0	838
NSW	8	N/A	N/A	N/A	N/A	N/A	N/A
VIC	4	151	70	-301	612	0	533
VIC	6	150	479	-168	491	0	952
VIC	7	79	72	-168	632	0	615
VIC	8	N/A	N/A	N/A	N/A	N/A	N/A
QLD	1	283	12	36	6	0	338
QLD	2	245	16	-13	2	0	251
QLD	3	172	12	-14	2	0	172
QLD	5	270	18	-13	2	0	277
SA	4	197	84	-301	82	0	61
SA	5	102	84	-301	82	0	-33
SA	6	195	134	-296	97	0	131
WA	1	189	68	-204	248	0	300
WA	3	114	68	-204	248	0	225
WA	4	182	112	-597	200	0	-103
WA	5	95	112	-597	200	0	-191
WA	6	180	628	-587	269	0	491
TAS	7	0	160	-5	267	0	422
NT	1	801	2	24	212	0	1,039
NT	3	801	2	0	204	0	1,007
ACT	7	0	96	143	242	0	481

[a] Includes the cost of solar panels and inverter (for the first year only). As noted in Chapter 5, inverters are assumed to be replaced in year 11, the cost of this second inverter is not included in this table.

Note: Negative numbers reflect savings in construction costs. Plant savings offsets only applicable to buildings that are 6 stars in the BAU. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table F.5 Estimated marginal construction costs under Option A — upgrade pathway for Class 1 dwellings with 6 stars and with PVs installed under the BAU (lowest cost upgrade pathway of alternative response options analysed), $/dwelling

Jurisdiction	NCC climate	Shell	Solar PV[a]	Heating and cooling	Hot Water	Plant savings (offset)	Total
NSW	2	706	0	-130	0	-145	431
NSW	4	372	0	-130	0	-145	97
NSW	5	1,308	0	-130	0	-145	1,033
NSW	6	210	0	-130	0	-145	-65
NSW	7	754	0	-130	0	-145	479
NSW	8	N/A	N/A	N/A	N/A	N/A	N/A
VIC	4	1,266	0	-328	0	-364	575
VIC	6	1,038	0	-328	0	-364	346
VIC	7	1,637	0	-328	0	-364	945
VIC	8	1,060	0	-328	0	-364	368
QLD	1	283	0	-128	0	-142	12
QLD	2	562	0	-128	0	-142	292
QLD	3	172	0	-128	0	-142	-99
QLD	5	1,041	0	-128	0	-142	771
SA	4	1,143	0	-209	0	-232	702
SA	5	1,129	0	-209	0	-232	688
SA	6	899	0	-209	0	-232	458
WA	1	517	0	-149	0	-166	203
WA	3	524	0	-149	0	-166	209
WA	4	1,128	0	-149	0	-166	813
WA	5	959	0	-149	0	-166	644
WA	6	884	37	-149	0	-166	606
TAS	7	1,621	49	-190	0	-211	1,269
NT	1	1,486	0	-127	0	-141	1,218
NT	3	1,288	0	-127	0	-141	1,019
ACT	7	321	6	-213	0	-236	-122

[a] Includes the cost of solar panels and inverter (for the first year only). As noted in Chapter 5, inverters are assumed to be replaced in year 11, the cost of this second inverter is not included in this table.

Note: Negative numbers reflect savings in construction costs. Plant savings offsets only applicable to buildings that are 6 stars in the BAU. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table F.6 Estimated marginal construction costs under Option B — upgrade pathway for Class 1 dwellings with 6 stars and with PVs installed under the BAU (lowest cost upgrade pathway of alternative response options analysed), $/dwelling

Jurisdiction	NCC climate	Shell	Solar PV[a]	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	2	706	0	-130	0	-145	431
NSW	4	372	0	-130	0	-145	97
NSW	5	1,308	0	-130	0	-145	1,033
NSW	6	210	0	-130	0	-145	-65
NSW	7	754	0	-130	0	-145	479
NSW	8	N/A	N/A	N/A	N/A	N/A	N/A
VIC	4	1,266	0	-328	0	-364	575
VIC	6	1,038	0	-328	0	-364	346
VIC	7	1,637	0	-328	0	-364	945
VIC	8	1,060	0	-328	0	-364	368
QLD	1	283	0	-128	0	-142	12
QLD	2	562	0	-128	0	-142	292
QLD	3	172	0	-128	0	-142	-99
QLD	5	1,041	0	-128	0	-142	771
SA	4	1,143	0	-209	0	-232	702
SA	5	1,129	0	-209	0	-232	688
SA	6	899	0	-209	0	-232	458
WA	1	517	0	-149	0	-166	203
WA	3	524	0	-149	0	-166	209
WA	4	1,128	0	-149	0	-166	813
WA	5	959	0	-149	0	-166	644
WA	6	884	0	-149	0	-166	569
TAS	7	1,621	3	-190	0	-211	1,223
NT	1	1,486	0	-127	0	-141	1,218
NT	3	1,288	0	-127	0	-141	1,019
ACT	7	321	0	-213	0	-236	-128

[a] Includes the cost of solar panels and inverter (for the first year only). As noted in Chapter 5, inverters are assumed to be replaced in year 11, the cost of this second inverter is not included in this table.

Note: Negative numbers reflect savings in construction costs. Plant savings offsets only applicable to buildings that are 6 stars in the BAU. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table F.7 Estimated marginal construction costs under Option A — upgrade pathway for Class 1 dwellings with 7 stars and with PVs installed under the BAU (lowest cost upgrade pathway of alternative response options analysed), $/dwelling

Jurisdiction	NCC climate	Shell	Solar PV[a]	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	2	191	0	0	0	0	191
NSW	4	212	0	0	0	0	212
NSW	5	210	0	0	0	0	210
NSW	6	210	0	0	0	0	210
NSW	7	110	0	0	0	0	110
NSW	8	N/A	N/A	N/A	N/A	N/A	N/A
VIC	4	151	0	0	0	0	151
VIC	6	150	0	0	0	0	150
VIC	7	79	0	0	0	0	79
VIC	8	N/A	N/A	N/A	N/A	N/A	N/A
QLD	1	283	0	0	0	0	283
QLD	2	245	0	0	0	0	245
QLD	3	172	0	0	0	0	172
QLD	5	270	0	0	0	0	270
SA	4	197	0	0	0	0	197
SA	5	102	0	0	0	0	102
SA	6	195	0	0	0	0	195
WA	1	189	0	0	0	0	189
WA	3	114	0	0	0	0	114
WA	4	182	0	0	0	0	182
WA	5	95	0	0	0	0	95
WA	6	180	37	0	0	0	218
TAS	7	0	49	0	0	0	49
NT	1	801	0	0	0	0	801
NT	3	801	0	0	0	0	801
NSW	2	191	0	0	0	0	191

[a] Includes the cost of solar panels and inverter (for the first year only). As noted in Chapter 5, inverters are assumed to be replaced in year 11, the cost of this second inverter is not included in this table.

Note: Negative numbers reflect savings in construction costs. Plant savings offsets only applicable to buildings that are 6 stars in the BAU. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table F.8 Estimated marginal construction costs under Option B — upgrade pathway for Class 1 dwellings with 7 stars and with PVs installed under the BAU (lowest cost upgrade pathway of alternative response options analysed), $/dwelling

Jurisdiction	NCC climate	Shell	Solar PV[a]	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	2	191	0	0	0	0	191
NSW	4	212	0	0	0	0	212
NSW	5	210	0	0	0	0	210
NSW	6	210	0	0	0	0	210
NSW	7	110	0	0	0	0	110
NSW	8	N/A	N/A	N/A	N/A	N/A	N/A
VIC	4	151	0	0	0	0	151
VIC	6	150	0	0	0	0	150
VIC	7	79	0	0	0	0	79
VIC	8	N/A	N/A	N/A	N/A	N/A	N/A
QLD	1	283	0	0	0	0	283
QLD	2	245	0	0	0	0	245
QLD	3	172	0	0	0	0	172
QLD	5	270	0	0	0	0	270
SA	4	197	0	0	0	0	197
SA	5	102	0	0	0	0	102
SA	6	195	0	0	0	0	195
WA	1	189	0	0	0	0	189
WA	3	114	0	0	0	0	114
WA	4	182	0	0	0	0	182
WA	5	95	0	0	0	0	95
WA	6	180	0	0	0	0	180
TAS	7	0	3	0	0	0	3
NT	1	801	0	0	0	0	801
NT	3	801	0	0	0	0	801
ACT	7	N/A	N/A	N/A	N/A	N/A	N/A

[a] Includes the cost of solar panels and inverter (for the first year only). As noted in Chapter 5, inverters are assumed to be replaced in year 11, the cost of this second inverter is not included in this table.

Note: Negative numbers reflect savings in construction costs. Plant savings offsets only applicable to buildings that are 6 stars in the BAU. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table F.9 Estimated marginal construction costs under Option A — upgrade pathway for Class 1 dwellings with 6 stars and with a pool or spa installed under the BAU (lowest cost upgrade pathway of alternative response options analysed), $/dwelling

Jurisdiction	NCC climate	Shell	Solar PV[a]	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	2	706	0	0	0	-145	561
NSW	4	372	4,427	0	0	-145	4,654
NSW	5	1,308	4,427	0	0	-145	5,591
NSW	6	210	4,427	0	0	-145	4,493
NSW	7	754	4,427	0	0	-145	5,037
NSW	8	492	4,427	0	0	-145	4,774
VIC	4	1,266	4,842	0	0	-364	5,744
VIC	6	1,038	4,842	0	0	-364	5,516
VIC	7	1,637	4,842	0	0	-364	6,115
VIC	8	1,060	4,842	0	0	-364	5,538
QLD	1	283	0	0	0	-142	140
QLD	2	562	0	0	0	-142	420
QLD	3	172	0	0	0	-142	29
QLD	5	1,041	0	0	0	-142	899
SA	4	1,143	5,109	0	0	-232	6,020
SA	5	1,129	5,109	0	0	-232	6,006
SA	6	899	5,109	0	0	-232	5,775
WA	1	517	3,957	0	0	-166	4,309
WA	3	524	3,957	0	0	-166	4,316
WA	4	1,128	0	0	0	-166	962
WA	5	959	0	0	0	-166	793
WA	6	884	0	0	0	-166	718
TAS	7	1,621	0	0	0	-211	1,410
NT	1	1,486	7,899	0	0	-141	9,244
NT	3	1,288	7,899	0	0	-141	9,045
ACT	7	321	4,536	0	0	-236	4,621

[a] Includes the cost of solar panels and inverter (for the first year only). As noted in Chapter 5, inverters are assumed to be replaced in year 11, the cost of this second inverter is not included in this table.

Note: Negative numbers reflect savings in construction costs. Plant savings offsets only applicable to buildings that are 6 stars in the BAU. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table F.10 Estimated marginal construction costs under Option B — upgrade pathway for Class 1 dwellings with 6 stars and with a pool or spa installed under the BAU (lowest cost upgrade pathway of alternative response options analysed), $/dwelling

Jurisdiction	NCC climate	Shell	Solar PV[a]	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	2	706	0	0	0	-145	561
NSW	4	372	0	0	0	-145	227
NSW	5	1,308	0	0	0	-145	1,164
NSW	6	210	0	0	0	-145	66
NSW	7	754	0	0	0	-145	610
NSW	8	492	0	0	0	-145	347
VIC	4	1,266	4,842	0	0	-364	5,744
VIC	6	1,038	4,842	0	0	-364	5,516
VIC	7	1,637	4,842	0	0	-364	6,115
VIC	8	1,060	4,842	0	0	-364	5,538
QLD	1	283	0	0	0	-142	140
QLD	2	562	0	0	0	-142	420
QLD	3	172	0	0	0	-142	29
QLD	5	1,041	0	0	0	-142	899
SA	4	1,143	0	0	0	-232	911
SA	5	1,129	0	0	0	-232	897
SA	6	899	0	0	0	-232	667
WA	1	517	0	0	0	-166	352
WA	3	524	0	0	0	-166	358
WA	4	1,128	0	0	0	-166	962
WA	5	959	0	0	0	-166	793
WA	6	884	0	0	0	-166	718
TAS	7	1,621	0	0	0	-211	1,410
NT	1	1,486	7,899	0	0	-141	9,244
NT	3	1,288	0	0	0	-141	1,146
ACT	7	321	0	0	0	-236	85

[a] Includes the cost of solar panels and inverter (for the first year only). As noted in Chapter 5, inverters are assumed to be replaced in year 11, the cost of this second inverter is not included in this table.

Note: Negative numbers reflect savings in construction costs. Plant savings offsets only applicable to buildings that are 6 stars in the BAU. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

F.2 Cost for Class 2 dwellings

This section presents the cost tables for Class 2 dwellings.

Table F.11 Estimated marginal construction costs under Option A — upgrade pathway for Class 2 dwellings with 6 stars in the BAU (all equipment upgrade pathway), $/dwelling

Jurisdiction	NCC climate	Shell	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	2	582	2,238	1,796	-151	4,465
NSW	4	360	2,262	1,781	-151	4,252
NSW	5	704	2,246	1,804	-151	4,602
NSW	6	502	2,178	1,889	-151	4,418
NSW	7	1,057	2,178	1,925	-151	5,010
VIC	6	501	2,822	1,686	-175	4,834
VIC	7	1,056	2,813	1,697	-175	5,390
QLD [a]	1	274	3,231	1,729	-112	5,122
QLD [a]	2	581	2,863	1,827	-112	5,160
QLD [a]	5	702	2,656	1,933	-112	5,178
SA	5	718	1,396	1,883	-159	3,838
WA	5	495	995	1,962	-123	3,329
TAS	7	423	373	1,923	-158	2,562
NT	1	421	3,366	1,252	-143	4,896
ACT	7	1,062	1,049	1,740	-171	3,680

[a] Results reflect the use of a heat pump water heater as the energy performance benchmark for Class 2 dwellings in Queensland and a gas instantaneous water heater benchmark for all other jurisdictions.

Note: Negative numbers reflect savings in construction costs. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table F.12 Estimated marginal construction costs under Option B — upgrade pathway for Class 2 dwellings with 6 stars in the BAU (all equipment upgrade pathway), $/dwelling

Jurisdiction	NCC climate	Shell	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	4	360	-43	141	-136	322
NSW	5	704	-61	152	-136	659
NSW	6	502	-45	146	-136	467
NSW	7	1,057	-30	162	-136	1,053
VIC	6	501	109	143	-157	596
VIC	7	1,056	147	117	-157	1,163
QLD [a]	1	274	147	1,763	-101	2,082
QLD [a]	2	581	-31	1,809	-101	2,258
QLD [a]	5	702	-11	1,827	-101	2,417
SA	5	718	-197	419	-143	797
WA	5	495	-332	384	-111	436
TAS	7	423	-126	1,164	-142	1,319
NT	1	421	-125	1,525	-129	1,693
ACT	7	1,062	-41	578	-154	1,445
NSW	4	360	-43	141	-136	322

[a] Results reflect the use of a heat pump water heater as the energy performance benchmark for Class 2 dwellings in Queensland and a gas instantaneous water heater benchmark for all other jurisdictions.

Note: Negative numbers reflect savings in construction costs. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table F.13 Estimated marginal construction costs under Option A — upgrade pathway for Class 2 dwellings with 7 stars in the BAU (all equipment upgrade pathway), $/dwelling

Jurisdiction	NCC climate	Shell	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	2	3	2,374	1,796	0	4,173
NSW	4	4	2,398	1,781	0	4,182
NSW	5	4	2,381	1,804	0	4,189
NSW	6	3	2,314	1,889	0	4,206
NSW	7	4	2,314	1,925	0	4,243
VIC	6	2	2,979	1,686	0	4,668
VIC	7	3	2,970	1,697	0	4,669
QLD [a]	1	2	3,332	1,729	0	5,063
QLD [a]	2	2	2,964	1,827	0	4,794
QLD [a]	5	3	2,757	1,933	0	4,692
SA	5	8	1,540	1,883	0	3,431
WA	5	42	1,106	1,962	0	3,110
TAS	7	1	516	1,923	0	2,440
NT	1	8	3,495	1,252	0	4,754
ACT	7	9	1,203	1,740	0	2,951

[a] Results reflect the use of a heat pump water heater as the energy performance benchmark for Class 2 dwellings in Queensland and a gas instantaneous water heater benchmark for all other jurisdictions.

Note: Negative numbers reflect savings in construction costs. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table F.14 Estimated marginal construction costs under Option B — upgrade pathway for Class 2 dwellings with 7 stars in the BAU (all equipment upgrade pathway), $/dwelling

hy	NCC climate	Shell	Heating and cooling	Hot water	Plant savings (offset)	Total
NSW	2	3	59	146	0	208
NSW	4	4	92	141	0	237
NSW	5	4	75	152	0	231
NSW	6	3	91	146	0	240
NSW	7	4	105	162	0	272
VIC	6	2	266	143	0	412
VIC	7	3	305	117	0	425
QLD [a]	1	2	248	1,763	0	2,013
QLD [a]	2	2	70	1,809	0	1,881
QLD [a]	5	3	90	1,827	0	1,920
SA	5	8	-54	419	0	374
WA	5	42	-221	384	0	205
TAS	7	1	16	1,164	0	1,181
NT	1	8	4	1,525	0	1,536
ACT	7	9	112	578	0	699

[a] Results reflect the use of a heat pump water heater as the energy performance benchmark for Class 2 dwellings in Queensland and a gas instantaneous water heater benchmark for all other jurisdictions.

Note: Negative numbers reflect savings in construction costs. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

G Changes in energy consumption for individual dwellings

This Appendix provides details of the estimated changes in energy consumption associated with the NCC 2022 under each upgrade pathways outlined in Chapter 5 for each of the climate zones and jurisdictions modelled by EES.

G.1 Class 1 dwellings

This section presents the energy flows tables for Class 1 dwellings.

Table G.1 Estimated changes in energy consumption under Option A — upgrade pathway for Class 1 dwellings with no PV and 6 stars in the BAU (lowest cost upgrade pathway of alternative response options analysed), MJ per dwelling

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
NSW	2	-3,572	-267	-7	-3,845	9,004	-76,102	-3,945	-213	-80,259	180,079
NSW	4	-4,381	-433	-57	-4,871	8,332	-99,273	-8,659	-1,710	-109,642	166,645
NSW	5	-3,879	-381	-27	-4,288	7,199	-85,240	-7,088	-818	-93,146	143,972
NSW	6	-4,225	-641	-136	-5,002	7,434	-92,562	-14,761	-4,069	-111,392	148,689
NSW	7	-4,686	-715	-115	-5,515	7,390	-108,848	-16,860	-3,438	-129,145	147,796
NSW	8	-5,123	-1,300	-261	-6,683	9,589	-116,935	-33,900	-7,817	-158,652	191,789
VIC	4	-2,748	-2,655	-134	-5,537	4,652	-60,065	-69,046	-4,015	-133,125	93,036
VIC	6	-1,393	-9,406	-318	-11,117	4,583	-15,926	-279,926	-9,542	-305,394	91,659
VIC	7	-1,673	-10,401	-270	-12,344	5,081	-23,391	-309,370	-8,094	-340,855	101,625
VIC	8	-3,085	-15,464	-577	-19,125	11,141	-51,407	-463,908	-17,310	-532,625	222,815
QLD	1	-4,290	-41	-0	-4,332	169	-64,069	-493	-2	-64,565	3,371
QLD	2	-1,771	-49	-5	-1,825	191	-24,635	-692	-164	-25,491	3,828
QLD	3	-4,411	-47	-10	-4,468	195	-65,404	-666	-304	-66,374	3,898
QLD	5	-4,461	-66	-20	-4,547	153	-60,763	-1,150	-613	-62,526	3,064
SA	4	-2,298	-1,221	-224	-3,743	2,455	-48,616	-29,897	-6,706	-85,219	49,094
SA	5	-2,128	-1,009	-108	-3,245	2,215	-45,630	-23,469	-3,238	-72,338	44,303

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
SA	6	-2,880	-2,355	-533	-5,768	3,905	-57,671	-64,067	-15,988	-137,726	78,099
WA	1	-1,802	-669	-0	-2,471	1,908	-41,215	-8,035	-4	-49,254	38,161
WA	3	-2,023	-954	-26	-3,003	2,202	-46,018	-16,446	-779	-63,243	44,044
WA	4	-1,494	-2,155	-111	-3,759	1,857	-31,414	-50,958	-3,324	-85,696	37,137
WA	5	-1,178	-1,997	-60	-3,235	1,928	-22,805	-46,975	-1,789	-71,569	38,551
WA	6	-1,662	-3,853	-264	-5,779	2,678	-29,424	-101,187	-7,916	-138,526	53,559
TAS	7	-4,512	-764	-1,004	-6,280	2,164	-72,291	-17,501	-30,107	-119,899	43,283
NT	1	-8,401	-0	0	-8,402	9,189	-209,897	-2	0	-209,899	183,771
NT	3	-2,091	-63	-3	-2,157	694	-47,218	-754	-83	-48,055	13,876
ACT	7	-2,638	-1,783	-88	-4,509	1,654	-49,447	-41,669	-2,653	-93,768	33,073

Note: Estimates for a 'composite' dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table G.2 Estimated changes in energy consumption under Option B — upgrade pathway for Class 1 dwellings with no PV and 6 stars in the BAU (lowest cost upgrade pathway of alternative response options analysed), MJ per dwelling

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
NSW	2	-738	-131	-7	-876	1,737	-15,694	-2,391	-213	-18,298	34,738
NSW	4	-1,271	-308	-57	-1,637	1,809	-30,641	-7,529	-1,710	-39,879	36,173
NSW	5	-1,003	-252	-27	-1,282	1,559	-22,949	-5,826	-818	-29,593	31,186
NSW	6	-1,084	-535	-136	-1,754	1,516	-25,369	-14,172	-4,069	-43,609	30,325
NSW	7	-1,232	-566	-115	-1,913	1,773	-29,256	-15,072	-3,438	-47,766	35,458
NSW	8	-4,037	-1,414	-261	-5,711	7,080	-95,242	-37,257	-7,817	-140,316	141,597
VIC	4	-938	-3,238	-134	-4,310	170	-15,338	-85,632	-4,015	-104,985	3,397
VIC	6	-485	-6,495	-318	-7,298	815	-2,939	-184,793	-9,542	-197,274	16,297
VIC	7	-543	-6,672	-270	-7,484	161	-1,642	-188,695	-8,094	-198,431	3,215
VIC	8	2,998	-30,551	-577	-28,130	2,002	106,192	-908,576	-17,310	-819,695	40,039
QLD	1	-661	-39	-0	-699	30	-19,861	-465	-2	-20,327	604
QLD	2	-162	-24	-5	-191	41	-4,784	-393	-164	-5,341	829
QLD	3	-649	-20	-10	-679	35	-19,412	-335	-304	-20,052	690
QLD	5	-375	-40	-20	-435	36	-11,154	-852	-613	-12,619	727
SA	4	-760	-1,123	-224	-2,107	193	-19,130	-31,016	-6,706	-56,852	3,858
SA	5	-705	-872	-108	-1,684	177	-17,478	-23,466	-3,238	-44,182	3,547

Jurisdiction	NCC climate	Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
		Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
SA	6	-542	-2,209	-533	-3,284	244	-11,524	-63,209	-15,988	-90,721	4,889
WA	1	-940	-612	-0	-1,552	203	-22,786	-7,351	-4	-30,142	4,053
WA	3	-1,069	-777	-26	-1,871	232	-26,307	-12,202	-779	-39,288	4,636
WA	4	-823	-1,742	-111	-2,676	331	-15,946	-46,786	-3,324	-66,056	6,613
WA	5	-566	-1,612	-60	-2,238	338	-8,832	-43,104	-1,789	-53,725	6,761
WA	6	-903	-3,851	-264	-5,017	1,406	-15,618	-101,163	-7,916	-124,697	28,128
TAS	7	-1,448	-638	-1,004	-3,090	308	-28,677	-15,992	-30,107	-74,775	6,162
NT	1	-2,158	-53	0	-2,211	3	-56,937	-636	0	-57,573	62
NT	3	-1,639	-14	-3	-1,656	3	-39,603	-164	-83	-39,850	68
ACT	7	-1,139	-1,440	-88	-2,667	258	-22,939	-37,546	-2,653	-63,138	5,163

Note: Estimates for a ‘composite’ dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table G.3 Estimated changes in energy consumption under Option A — upgrade pathway for Class 1 dwellings with no PV and 7 stars in the BAU (lowest cost upgrade pathway of alternative response options analysed), MJ per dwelling

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
NSW	2	-3,430	-267	-1	-3,698	9,004	-71,843	-3,952	-29	-75,824	180,079
NSW	4	-3,842	-447	-8	-4,297	8,332	-83,124	-9,068	-227	-92,419	166,645
NSW	5	-3,553	-404	-5	-3,962	7,199	-75,433	-7,776	-159	-83,368	143,972
NSW	6	-3,792	-619	-8	-4,419	7,434	-79,564	-14,092	-232	-93,887	148,689
NSW	7	-4,203	-782	-17	-5,002	7,390	-94,349	-18,886	-519	-113,754	147,796
NSW	8	0	0	0	0	0	0	0	0	0	0
VIC	4	-2,272	-1,746	-11	-4,030	4,652	-45,777	-41,783	-342	-87,903	93,036
VIC	6	-1,187	-6,874	-12	-8,073	4,583	-9,759	-203,954	-349	-214,062	91,659
VIC	7	-1,282	-8,787	-26	-10,096	5,081	-11,663	-260,953	-784	-273,399	101,625
VIC	8	0	0	0	0	0	0	0	0	0	0
QLD	1	-3,689	-41	-0	-3,730	169	-46,032	-493	-0	-46,525	3,371
QLD	2	-1,628	-49	-1	-1,678	191	-20,344	-693	-26	-21,064	3,828
QLD	3	-3,795	-47	0	-3,842	195	-46,922	-659	0	-47,581	3,898
QLD	5	-4,133	-70	-5	-4,207	153	-50,917	-1,257	-145	-52,319	3,064
SA	4	-1,652	-1,229	-25	-2,905	2,455	-29,224	-30,119	-742	-60,085	49,094
SA	5	-1,553	-1,045	-19	-2,617	2,215	-28,366	-24,560	-569	-53,495	44,303

Jurisdiction	NCC climate	Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
		Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
SA	6	-2,380	-2,163	-25	-4,568	3,905	-42,679	-58,295	-757	-101,730	78,099
WA	1	-1,182	-668	-0	-1,850	1,908	-22,598	-8,018	-0	-30,616	38,161
WA	3	-1,270	-937	0	-2,207	2,202	-23,426	-15,937	0	-39,363	44,044
WA	4	-972	-2,209	-11	-3,192	1,857	-15,773	-52,574	-342	-68,690	37,137
WA	5	-868	-2,105	-11	-2,984	1,928	-13,497	-50,201	-326	-64,024	38,551
WA	6	-1,300	-3,642	-12	-4,954	2,678	-18,565	-94,860	-349	-113,774	53,559
TAS	7	-3,873	-704	0	-4,577	2,164	-53,122	-15,710	0	-68,832	43,283
NT	1	-7,028	-0	0	-7,029	9,189	-168,705	-2	0	-168,707	183,771
NT	3	-1,135	-63	0	-1,198	694	-18,543	-754	0	-19,297	13,876
ACT	7	-1,987	-1,622	0	-3,608	1,654	-29,911	-36,826	0	-66,737	33,073

Note: Estimates for a 'composite' dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table G.4 Estimated changes in energy consumption under Option B — upgrade pathway for Class 1 dwellings with no PV and 7 stars in the BAU (lowest cost upgrade pathway of alternative response options analysed), MJ per dwelling

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
NSW	2	-596	-131	-1	-728	1,737	-11,435	-2,399	-29	-13,863	34,738
NSW	4	-733	-322	-8	-1,062	1,809	-14,492	-7,938	-227	-22,657	36,173
NSW	5	-676	-275	-5	-956	1,559	-13,142	-6,514	-159	-19,814	31,186
NSW	6	-651	-512	-8	-1,171	1,516	-12,370	-13,503	-232	-26,105	30,325
NSW	7	-749	-634	-17	-1,400	1,773	-14,757	-17,099	-519	-32,375	35,458
NSW	8	0	0	0	0	0	0	0	0	0	0
VIC	4	-462	-2,329	-11	-2,803	170	-1,051	-58,369	-342	-59,762	3,397
VIC	6	-279	-3,963	-12	-4,254	815	3,228	-108,821	-349	-105,942	16,297
VIC	7	-152	-5,058	-26	-5,236	161	10,086	-140,278	-784	-130,976	3,215
VIC	8	0	0	0	0	0	0	0	0	0	0
QLD	1	-59	-39	-0	-98	30	-1,824	-464	-0	-2,288	604
QLD	2	-19	-24	-1	-44	41	-494	-394	-26	-914	829
QLD	3	-33	-19	0	-53	35	-931	-328	0	-1,259	690
QLD	5	-47	-44	-5	-95	36	-1,309	-959	-145	-2,413	727
SA	4	-114	-1,131	-25	-1,269	193	262	-31,239	-742	-31,719	3,858
SA	5	-129	-908	-19	-1,056	177	-214	-24,556	-569	-25,340	3,547

Jurisdiction	NCC climate	Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
		Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
SA	6	-43	-2,017	-25	-2,084	244	3,468	-57,436	-757	-54,726	4,889
WA	1	-320	-611	-0	-931	203	-4,169	-7,334	-0	-11,503	4,053
WA	3	-316	-760	0	-1,075	232	-3,715	-11,692	0	-15,408	4,636
WA	4	-301	-1,796	-11	-2,109	331	-305	-48,402	-342	-49,050	6,613
WA	5	-256	-1,720	-11	-1,986	338	476	-46,330	-326	-46,180	6,761
WA	6	-541	-3,640	-12	-4,192	1,406	-4,760	-94,836	-349	-99,945	28,128
TAS	7	-809	-578	0	-1,388	308	-9,508	-14,200	0	-23,708	6,162
NT	1	-785	-53	0	-838	3	-15,744	-636	0	-16,381	62
NT	3	-684	-14	0	-697	3	-10,928	-164	0	-11,092	68
ACT	7	-488	-1,278	0	-1,766	258	-3,403	-32,703	0	-36,106	5,163

Note: Estimates for a ‘composite’ dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table G.5 Estimated changes in energy consumption under Option A — upgrade pathway for Class 1 dwellings with 6 stars and with PVs installed under the BAU (lowest cost upgrade pathway of alternative response options analysed), MJ per dwelling

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
NSW	2	-47	-6	-6	-58	108	-1,328	-169	-185	-1,682	2,152
NSW	4	-297	-47	-49	-394	335	-8,568	-1,400	-1,483	-11,451	6,703
NSW	5	-127	-19	-22	-168	224	-3,739	-560	-659	-4,959	4,475
NSW	6	-387	-119	-128	-634	82	-11,392	-3,581	-3,837	-18,811	1,649
NSW	7	-340	-75	-97	-512	266	-9,874	-2,249	-2,918	-15,041	5,311
NSW	8	0	0	0	0	0	0	0	0	0	0
VIC	4	-218	-1,203	-122	-1,543	310	-6,226	-36,084	-3,672	-45,982	6,195
VIC	6	-194	-3,008	-306	-3,508	16	-5,685	-90,228	-9,193	-105,105	320
VIC	7	-217	-2,309	-244	-2,769	225	-6,244	-69,268	-7,310	-82,822	4,493
VIC	8	-376	-4,851	-506	-5,733	85	-10,980	-145,523	-15,193	-171,696	1,707
QLD	1	-166	-0	-0	-166	512	-4,774	-0	-2	-4,776	10,238
QLD	2	-51	-1	-5	-56	106	-1,416	-24	-138	-1,578	2,112
QLD	3	-411	-2	-10	-423	387	-11,981	-62	-304	-12,347	7,731
QLD	5	-130	-2	-16	-148	222	-3,796	-75	-468	-4,339	4,445
SA	4	-353	-220	-199	-772	363	-10,159	-6,611	-5,964	-22,734	7,250
SA	5	-241	-98	-89	-428	387	-6,931	-2,944	-2,669	-12,545	7,741

Jurisdiction	NCC climate	Change in annual energy consumption (MJ) Electricity	Gas	LPG and firewood	Total	Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ) Electricity	Gas	LPG and firewood	Total	Total PV exports (2022-2060 MJ)
SA	6	-449	-559	-508	-1,516	63	-13,143	-16,784	-15,231	-45,157	1,260
WA	1	-192	-1	-0	-193	476	-5,596	-17	-4	-5,617	9,518
WA	3	-474	-98	-26	-598	346	-13,930	-2,942	-779	-17,650	6,910
WA	4	-273	-328	-99	-700	306	-7,819	-9,835	-2,982	-20,635	6,127
WA	5	-146	-145	-49	-340	192	-4,196	-4,342	-1,463	-10,002	3,848
WA	6	-331	-833	-252	-1,416	175	-9,658	-24,988	-7,566	-42,212	3,508
TAS	7	-561	-147	-1,004	-1,712	239	-16,276	-4,419	-30,107	-50,801	4,789
NT	1	-510	0	0	-510	1,015	-14,900	0	0	-14,900	20,294
NT	3	-612	0	-3	-615	447	-17,980	0	-83	-18,063	8,939
ACT	7	-482	-220	-88	-790	333	-13,824	-6,586	-2,653	-23,063	6,662

Note: Estimates for a 'composite' dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table G.6 Estimated changes in energy consumption under Option B — upgrade pathway for Class 1 dwellings with 6 stars and with PVs installed under the BAU (lowest cost upgrade pathway of alternative response options analysed), MJ per dwelling

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
NSW	2	-45	-6	-6	-57	108	-1,296	-169	-185	-1,650	2,160
NSW	4	-298	-47	-49	-394	335	-8,560	-1,400	-1,483	-11,443	6,696
NSW	5	-126	-19	-22	-167	223	-3,726	-560	-659	-4,945	4,464
NSW	6	-386	-119	-128	-633	83	-11,346	-3,581	-3,837	-18,765	1,656
NSW	7	-340	-75	-97	-512	266	-9,888	-2,249	-2,918	-15,056	5,328
NSW	8	0	0	0	0	0	0	0	0	0	0
VIC	4	-217	-1,203	-122	-1,542	310	-6,221	-36,084	-3,672	-45,977	6,192
VIC	6	-194	-3,008	-306	-3,508	14	-5,683	-90,228	-9,193	-105,104	288
VIC	7	-214	-2,309	-244	-2,766	223	-6,195	-69,268	-7,310	-82,773	4,464
VIC	8	-376	-4,851	-506	-5,733	86	-10,971	-145,523	-15,193	-171,687	1,728
QLD	1	-165	-0	-0	-165	511	-4,743	-0	-2	-4,746	10,224
QLD	2	-52	-1	-5	-57	104	-1,432	-24	-138	-1,594	2,088
QLD	3	-411	-2	-10	-424	385	-11,975	-62	-304	-12,342	7,704
QLD	5	-130	-2	-16	-148	223	-3,823	-75	-468	-4,366	4,464
SA	4	-353	-220	-199	-772	364	-10,154	-6,611	-5,964	-22,729	7,272
SA	5	-240	-98	-89	-427	389	-6,908	-2,944	-2,669	-12,521	7,776

Jurisdiction	NCC climate	Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
		Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
SA	6	-447	-559	-508	-1,514	61	-13,109	-16,784	-15,231	-45,123	1,224
WA	1	-191	-1	-0	-192	475	-5,579	-17	-4	-5,601	9,504
WA	3	-473	-98	-26	-597	346	-13,906	-2,942	-779	-17,627	6,912
WA	4	-272	-328	-99	-699	306	-7,815	-9,835	-2,982	-20,631	6,120
WA	5	-146	-145	-49	-339	191	-4,186	-4,342	-1,463	-9,992	3,816
WA	6	-327	-827	-252	-1,406	43	-9,603	-24,796	-7,566	-41,965	864
TAS	7	-561	-147	-1,004	-1,711	104	-16,239	-4,419	-30,107	-50,764	2,088
NT	1	-509	0	0	-509	1,015	-14,878	0	0	-14,878	20,304
NT	3	-612	0	-3	-615	446	-17,963	0	-83	-18,045	8,928
ACT	7	-483	-220	-88	-791	306	-13,841	-6,586	-2,653	-23,080	6,120

Note: Estimates for a ‘composite’ dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumptionn. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table G.7 Estimated changes in energy consumption under Option A — upgrade pathway for Class 1 dwellings with 7 stars and with PVs installed under the BAU (lowest cost upgrade pathway of alternative response options analysed), MJ per dwelling

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
NSW	2	0	0	0	0	0	0	0	0	0	0
NSW	4	0	0	0	0	0	0	0	0	0	0
NSW	5	0	0	0	0	0	0	0	0	0	0
NSW	6	0	0	0	0	0	0	0	0	0	0
NSW	7	0	0	0	0	0	0	0	0	0	0
NSW	8	0	0	0	0	0	0	0	0	0	0
VIC	4	0	0	0	0	0	0	0	0	0	0
VIC	6	0	0	0	0	0	0	0	0	0	0
VIC	7	0	0	0	0	0	0	0	0	0	0
VIC	8	0	0	0	0	0	0	0	0	0	0
QLD	1	0	0	0	0	0	0	0	0	0	0
QLD	2	0	0	0	0	0	0	0	0	0	0
QLD	3	0	0	0	0	0	0	0	0	0	0
QLD	5	0	0	0	0	0	0	0	0	0	0
SA	4	0	0	0	0	0	0	0	0	0	0
SA	5	0	0	0	0	0	0	0	0	0	0

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
SA	6	0	0	0	0	0	0	0	0	0	0
WA	1	0	0	0	0	0	0	0	0	0	0
WA	3	0	0	0	0	0	0	0	0	0	0
WA	4	0	0	0	0	0	0	0	0	0	0
WA	5	0	0	0	0	0	0	0	0	0	0
WA	6	-2	-6	0	-8	133	-46	-192	0	-238	2,652
TAS	7	-2	0	0	-2	144	-42	0	0	-42	2,883
NT	1	0	0	0	0	0	0	0	0	0	0
NT	3	0	0	0	0	0	0	0	0	0	0
ACT	7	-0	0	0	-0	25	-5	0	0	-5	510

Note: Estimates for a ‘composite’ dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest.

Source: ACIL Allen based on EES data.

Table G.8 Estimated changes in energy consumption under Option B — upgrade pathway for Class 1 dwellings with 7 stars and with PVs installed under the BAU (lowest cost upgrade pathway of alternative response options analysed), MJ per dwelling

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
NSW	2	0	0	0	0	0	0	0	0	0	0
NSW	4	0	0	0	0	0	0	0	0	0	0
NSW	5	0	0	0	0	0	0	0	0	0	0
NSW	6	0	0	0	0	0	0	0	0	0	0
NSW	7	0	0	0	0	0	0	0	0	0	0
NSW	8	0	0	0	0	0	0	0	0	0	0
VIC	4	0	0	0	0	0	0	0	0	0	0
VIC	6	0	0	0	0	0	0	0	0	0	0
VIC	7	0	0	0	0	0	0	0	0	0	0
VIC	8	0	0	0	0	0	0	0	0	0	0
QLD	1	0	0	0	0	0	0	0	0	0	0
QLD	2	0	0	0	0	0	0	0	0	0	0
QLD	3	0	0	0	0	0	0	0	0	0	0
QLD	5	0	0	0	0	0	0	0	0	0	0
SA	4	0	0	0	0	0	0	0	0	0	0
SA	5	0	0	0	0	0	0	0	0	0	0

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
SA	6	0	0	0	0	0	0	0	0	0	0
WA	1	0	0	0	0	0	0	0	0	0	0
WA	3	0	0	0	0	0	0	0	0	0	0
WA	4	0	0	0	0	0	0	0	0	0	0
WA	5	0	0	0	0	0	0	0	0	0	0
WA	6	0	0	0	0	0	0	0	0	0	0
TAS	7	-0	0	0	-0	8	-3	0	0	-3	160
NT	1	0	0	0	0	0	0	0	0	0	0
NT	3	0	0	0	0	0	0	0	0	0	0
ACT	7	0	0	0	0	0	0	0	0	0	0

Note: Estimates for a ‘composite’ dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest.

Source: ACIL Allen based on EES data.

Table G.9 Estimated changes in energy consumption under Option A— upgrade pathway for Class 1 dwellings with 6 stars and with a pool or spa installed under the BAU (lowest cost upgrade pathway of alternative response options analysed), MJ per dwelling

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
NSW	2	-2,159	0	0	-2,159	0	-28,559	0	0	-28,559	0
NSW	4	-8,173	0	0	-8,173	8,414	-165,620	0	0	-165,620	168,289
NSW	5	-7,345	0	0	-7,345	7,027	-142,276	0	0	-142,276	140,536
NSW	6	-7,270	0	0	-7,270	6,460	-142,414	0	0	-142,414	129,198
NSW	7	-9,123	0	0	-9,123	6,662	-193,491	0	0	-193,491	133,233
NSW	8	-8,540	0	0	-8,540	6,876	-183,560	0	0	-183,560	137,516
VIC	4	-8,287	0	0	-8,287	8,414	-169,058	0	0	-169,058	168,289
VIC	6	-7,404	0	0	-7,404	6,460	-146,428	0	0	-146,428	129,198
VIC	7	-9,279	0	0	-9,279	6,662	-198,173	0	0	-198,173	133,233
VIC	8	-8,642	0	0	-8,642	6,876	-186,617	0	0	-186,617	137,516
QLD	1	-3,050	0	0	-3,050	0	-55,289	0	0	-55,289	0
QLD	2	-352	0	0	-352	0	-10,546	0	0	-10,546	0
QLD	3	-2,733	0	0	-2,733	0	-45,789	0	0	-45,789	0
QLD	5	-642	0	0	-642	0	-19,273	0	0	-19,273	0
SA	4	-8,280	0	0	-8,280	8,414	-168,836	0	0	-168,836	168,289
SA	5	-8,233	0	0	-8,233	7,255	-166,035	0	0	-166,035	145,098

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
SA	6	-7,407	0	0	-7,407	6,460	-146,524	0	0	-146,524	129,198
WA	1	-9,047	0	0	-9,047	7,672	-194,102	0	0	-194,102	153,436
WA	3	-9,341	0	0	-9,341	9,067	-201,940	0	0	-201,940	181,344
WA	4	-2,924	0	0	-2,924	0	-51,502	0	0	-51,502	0
WA	5	-2,507	0	0	-2,507	0	-38,981	0	0	-38,981	0
WA	6	-2,800	0	0	-2,800	0	-47,791	0	0	-47,791	0
TAS	7	-2,399	0	0	-2,399	0	-48,945	0	0	-48,945	0
NT	1	-10,894	0	0	-10,894	7,543	-260,598	0	0	-260,598	150,856
NT	3	-9,511	0	0	-9,511	9,067	-207,067	0	0	-207,067	181,344
ACT	7	-8,988	0	0	-8,988	6,662	-189,444	0	0	-189,444	133,233

Note: Estimates for a 'composite' dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest.

Source: ACIL Allen based on EES data.

Table G.10 Estimated changes in energy consumption under Option B — upgrade pathway for Class 1 dwellings with 6 stars and with a pool or spa installed under the BAU (lowest cost upgrade pathway of alternative response options analysed), MJ per dwelling

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
NSW	2	-348	0	0	-348	0	-10,452	0	0	-10,452	0
NSW	4	-1,011	0	0	-1,011	0	-30,345	0	0	-30,345	0
NSW	5	-626	0	0	-626	0	-18,780	0	0	-18,780	0
NSW	6	-864	0	0	-864	0	-25,921	0	0	-25,921	0
NSW	7	-1,156	0	0	-1,156	0	-34,676	0	0	-34,676	0
NSW	8	-3,166	0	0	-3,166	0	-71,948	0	0	-71,948	0
VIC	4	-8,287	0	0	-8,287	8,414	-169,058	0	0	-169,058	168,289
VIC	6	-7,404	0	0	-7,404	6,460	-146,428	0	0	-146,428	129,198
VIC	7	-9,279	0	0	-9,279	6,662	-198,173	0	0	-198,173	133,233
VIC	8	-8,642	0	0	-8,642	6,876	-186,617	0	0	-186,617	137,516
QLD	1	-1,239	0	0	-1,239	0	-37,182	0	0	-37,182	0
QLD	2	-352	0	0	-352	0	-10,546	0	0	-10,546	0
QLD	3	-923	0	0	-923	0	-27,682	0	0	-27,682	0
QLD	5	-642	0	0	-642	0	-19,273	0	0	-19,273	0
SA	4	-1,119	0	0	-1,119	0	-33,561	0	0	-33,561	0
SA	5	-946	0	0	-946	0	-28,369	0	0	-28,369	0

		Change in annual energy consumption (MJ)				Annual PV exports (MJ)	Change in energy consumption, total 2022-2060 (MJ)				Total PV exports (2022-2060 MJ)
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total		Electricity	Gas	LPG and firewood	Total	
SA	6	-1,001	0	0	-1,001	0	-30,032	0	0	-30,032	0
WA	1	-1,302	0	0	-1,302	0	-39,047	0	0	-39,047	0
WA	3	-1,297	0	0	-1,297	0	-38,898	0	0	-38,898	0
WA	4	-1,113	0	0	-1,113	0	-33,395	0	0	-33,395	0
WA	5	-696	0	0	-696	0	-20,874	0	0	-20,874	0
WA	6	-989	0	0	-989	0	-29,684	0	0	-29,684	0
TAS	7	-1,248	0	0	-1,248	0	-37,430	0	0	-37,430	0
NT	1	-10,894	0	0	-10,894	7,543	-260,598	0	0	-260,598	150,856
NT	3	-2,619	0	0	-2,619	0	-55,540	0	0	-55,540	0
ACT	7	-1,021	0	0	-1,021	0	-30,630	0	0	-30,630	0

Note: Estimates for a ‘composite’ dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. N/A notes where there are no buildings assumed to use this upgrade pathway in the modelling in the jurisdiction/climate zone of interest.

Source: ACIL Allen based on EES data.

G.2 Class 2 dwellings

This section presents the energy flows tables for Class 2 dwellings.

Table G.11 Estimated changes in energy consumption under Option A — upgrade pathway for Class 2 dwellings with 6 stars in the BAU (all equipment upgrade pathway), MJ per dwelling

		Change in annual energy consumption (MJ)				Change in energy consumption, total 2022-2060 (MJ)			
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total	Electricity	Gas	LPG and firewood	Total
NSW	2	289	-6,952	-0	-6,663	-4,295	-83,485	-0	-87,780
NSW	4	-405	-7,230	-0	-7,635	-24,463	-88,080	-2	-112,545
NSW	5	181	-7,094	-0	-6,913	-7,320	-85,368	-0	-92,688
NSW	6	344	-8,324	-0	-7,979	-9,118	-100,741	-1	-109,860
NSW	7	-468	-8,630	-0	-9,098	-30,971	-105,723	-4	-136,697
VIC	6	1,042	-9,696	0	-8,654	-3,984	-121,815	0	-125,799
VIC	7	180	-10,451	0	-10,271	-28,567	-139,194	0	-167,761
QLD [a]	1	-6,470	-316	0	-6,786	-112,893	-3,798	0	-116,691
QLD [a]	2	-4,930	-317	0	-5,248	-70,627	-3,825	0	-74,452
QLD [a]	5	-5,106	-326	0	-5,432	-73,138	-3,974	0	-77,112
SA	5	275	-7,884	0	-7,609	-7,087	-101,098	0	-108,185
WA	5	596	-8,196	0	-7,601	-3,224	-105,300	0	-108,524
TAS	7	-4,477	-2,613	0	-7,090	-70,272	-36,886	0	-107,158

		Change in annual energy consumption (MJ)				Change in energy consumption, total 2022-2060 (MJ)			
NT	1	-5,269	-197	0	-5,466	-117,118	-2,359	0	-119,478
ACT	7	-2,248	-5,669	0	-7,917	-47,847	-78,426	0	-126,273

[a] Results reflect the use of a heat pump water heater as the energy performance benchmark for Class 2 dwellings in Queensland and a gas instantaneous water heater benchmark for all other jurisdictions.

Note: Estimates for a 'composite' dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table G.12 Estimated changes in energy consumption under Option B — upgrade pathway for Class 2 dwellings with 6 stars in the BAU (all equipment upgrade pathway), MJ per dwelling

		Change in annual energy consumption (MJ)				Change in energy consumption, total 2022-2060 (MJ)			
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total	Electricity	Gas	LPG and firewood	Total
NSW	2	-445	-334	0	-780	-4,295	-83,485	-0	-87,780
NSW	4	-903	-452	-0	-1,355	-24,463	-88,080	-2	-112,545
NSW	5	-566	-382	-0	-948	-12,839	-4,826	-0	-17,665
NSW	6	-706	-433	-0	-1,138	-16,589	-5,969	-1	-22,559
NSW	7	-1,135	-530	-0	-1,664	-28,865	-8,518	-3	-37,386
VIC	6	-527	-1,435	0	-1,962	-14,730	-21,310	0	-36,040
VIC	7	-944	-1,893	0	-2,836	-26,311	-36,487	0	-62,798
QLD [a]	1	-4,545	-314	0	-4,859	-67,638	-3,769	0	-71,407
QLD [a]	2	-3,946	-317	0	-4,263	-50,229	-3,823	0	-54,052

		Change in annual energy consumption (MJ)				Change in energy consumption, total 2022-2060 (MJ)			
QLD [a]	5	-4,238	-326	0	-4,563	-55,795	-3,970	0	-59,765
SA	5	-1,175	-888	0	-2,063	-20,095	-17,071	0	-37,166
WA	5	-935	-1,003	0	-1,938	-17,481	-19,033	0	-36,514
TAS	7	-3,688	-570	0	-4,258	-58,886	-12,328	0	-71,214
NT	1	-3,512	-27	0	-3,540	-58,773	-328	0	-59,101
ACT	7	-2,143	-969	0	-3,112	-40,537	-21,740	0	-62,277

[a] Results reflect the use of a heat pump water heater as the energy performance benchmark for Class 2 dwellings in Queensland and a gas instantaneous water heater benchmark for all other jurisdictions.

Note: Estimates for a 'composite' dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table G.13 Estimated changes in energy consumption under Option A — upgrade pathway for Class 2 dwellings with 7 stars in the BAU (all equipment upgrade pathway), MJ per dwelling

		Change in annual energy consumption (MJ)				Change in energy consumption, total 2022-2060 (MJ)			
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total	Electricity	Gas	LPG and firewood	Total
NSW	2	495	-6,952	-0	-6,457	1,892	-83,496	-0	-81,604
NSW	4	232	-7,200	-0	-6,968	-5,365	-87,183	-1	-92,549
NSW	5	507	-7,094	-0	-6,587	2,467	-85,361	-0	-82,895
NSW	6	778	-8,313	-0	-7,535	3,885	-100,411	-1	-96,527
NSW	7	351	-8,606	-0	-8,255	-6,405	-105,007	-3	-111,416

		Change in annual energy consumption (MJ)				Change in energy consumption, total 2022-2060 (MJ)			
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total	Electricity	Gas	LPG and firewood	Total
VIC	6	1,497	-9,626	0	-8,128	9,671	-119,713	0	-110,043
VIC	7	1,038	-10,300	0	-9,262	-2,836	-134,640	0	-137,476
QLD [a]	1	-5,908	-316	0	-6,224	-96,042	-3,798	0	-99,840
QLD [a]	2	-4,776	-317	0	-5,094	-66,007	-3,827	0	-69,834
QLD [a]	5	-4,863	-326	0	-5,189	-65,828	-3,972	0	-69,800
SA	5	630	-7,804	0	-7,174	3,552	-98,694	0	-95,143
WA	5	985	-8,172	0	-7,187	8,450	-104,580	0	-96,130
TAS	7	-3,633	-2,532	0	-6,166	-44,976	-34,449	0	-79,424
NT	1	-4,356	-197	0	-4,553	-89,736	-2,359	0	-92,095
ACT	7	-1,388	-5,555	0	-6,942	-22,051	-74,990	0	-97,042

[a] Results reflect the use of a heat pump water heater as the energy performance benchmark for Class 2 dwellings in Queensland and a gas instantaneous water heater benchmark for all other jurisdictions.

Note: Estimates for a ‘composite’ dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

Table G.14 Estimated changes in energy consumption under Option B — upgrade pathway for Class 2 dwellings with 7 stars in the BAU (all equipment upgrade pathway), MJ per dwelling

		Change in annual energy consumption (MJ)				Change in energy consumption, total 2022-2060 (MJ)			
Jurisdiction	NCC climate	Electricity	Gas	LPG and firewood	Total	Electricity	Gas	LPG and firewood	Total
NSW	2	-239	-335	0	-574	1,892	-83,496	-0	-81,604
NSW	4	-267	-422	-0	-689	-5,365	-87,183	-1	-92,549
NSW	5	-240	-382	-0	-622	-3,053	-4,819	-0	-7,872
NSW	6	-272	-422	-0	-694	-3,587	-5,638	-1	-9,226
NSW	7	-316	-506	-0	-822	-4,300	-7,803	-2	-12,105
VIC	6	-71	-1,365	0	-1,436	-1,076	-19,207	0	-20,283
VIC	7	-86	-1,741	0	-1,827	-580	-31,933	0	-32,514
QLD [a]	1	-3,983	-314	0	-4,297	-50,787	-3,770	0	-54,557
QLD [a]	2	-3,792	-317	0	-4,109	-45,608	-3,826	0	-49,434
QLD [a]	5	-3,994	-326	0	-4,320	-48,484	-3,968	0	-52,452
SA	5	-821	-808	0	-1,628	-9,456	-14,667	0	-24,123
WA	5	-546	-979	0	-1,525	-5,807	-18,313	0	-24,120
TAS	7	-2,845	-488	0	-3,333	-33,590	-9,891	0	-43,481
NT	1	-2,599	-27	0	-2,627	-31,390	-328	0	-31,718
ACT	7	-1,283	-855	0	-2,138	-14,741	-18,304	0	-33,045

[a] Results reflect the use of a heat pump water heater as the energy performance benchmark for Class 2 dwellings in Queensland and a gas instantaneous water heater benchmark for all other jurisdictions.

Note: Estimates for a 'composite' dwelling for climate zones/jurisdiction that accounts for the number of dwellings that would take each of the upgrade pathways described in Chapter 5. Positive numbers indicate increases in energy consumption and negatives numbers denote decreases in energy consumption. Totals may not add up due to rounding.

Source: ACIL Allen based on EES data.

H State and territory results

This appendix presents the estimated costs and benefits of the proposed policy options for the NCC 2022 on individual states and territories of Australia.

Table H.1 Estimated lifetime (2022-2060) economy-wide costs and benefits of different policy options, present value ($M, 2021), NSW

	Option A	Option B	Option A for Class 1 + Option B for Class 2
COSTS			
Households - capital (resource) costs	1,184.9	276.0	714.8
Industry			
Training costs (incl. training time and training fees)	20.7	20.7	20.7
Redesign costs (volume builders)	7.8	7.8	7.8
Transition costs (custom builders)	27.5	27.5	27.5
Administrative costs (all buildings)	5.4	5.4	5.4
Government Costs	0.2	0.2	0.2
TOTAL COSTS	**1,246.4**	**337.6**	**776.4**
BENEFITS			
Households			
Electricity savings	382.5	106.4	397.5
Gas savings	85.8	12.5	13.9
LPG and firewood savings	2.9	2.9	2.9
Households offsetting amenity benefit	32.3	9.4	26.0
Household subtotal	**503.4**	**131.3**	**440.3**

	Option A	Option B	Option A for Class 1 + Option B for Class 2
Society			
Deferred/avoided generation, transmission and distribution investment for gas and electricity	37.6	16.1	43.9
Greenhouse emissions savings	158.1	35.3	120.7
Health benefits from reduced electricity generation and use of wood and gas	64.5	20.0	62.6
Society subtotal	**260.2**	**71.4**	**227.2**
TOTAL BENEFITS	**763.6**	**202.7**	**667.5**
NET PRESENT VALUES			
Accounting for energy benefits only	-705.4	-190.2	-292.2
Accounting for energy benefits + carbon benefits	-547.3	-154.9	-171.5
Accounting for energy benefits + carbon benefits + health benefits	-482.8	-134.9	-108.9
BCR (RATIO)			
Accounting for energy benefits only	0.43	0.44	0.62
Accounting for energy benefits + carbon benefits	0.56	0.54	0.78
Accounting for energy benefits + carbon benefits + health benefits	0.61	0.60	0.86

Note: Using a 7 per cent discount rate. Totals may not add up due to rounding.
Source: ACIL Allen.

Table H.2 Estimated lifetime (2022-2060) economy-wide costs and benefits of different policy options, present value ($M, 2021), Victoria

	Option A	Option B	Option A for Class 1 + Option B for Class 2
COSTS			
Households - capital (resource) costs	1,273.2	536.9	893.9
Industry			
Training costs (incl. training time and training fees)	17.4	17.4	17.4
Redesign costs (volume builders)	8.5	8.5	8.5
Transition costs (custom builders)	31.2	31.2	31.2

	Option A	Option B	Option A for Class 1 + Option B for Class 2
Administrative costs (all buildings)	6.2	6.2	6.2
Government Costs	0.2	0.2	0.2
TOTAL COSTS	**1,336.7**	**600.4**	**957.4**
BENEFITS			
Households			
Electricity savings	235.7	79.4	261.5
Gas savings	364.6	212.8	303.7
LPG and firewood savings	15.5	15.5	15.5
Households offsetting amenity benefit	52.0	31.0	48.1
Household subtotal	**667.8**	**338.7**	**628.9**
Society			
Deferred/avoided generation, transmission and distribution investment for gas and electricity	-325.7	10.2	-322.8
Greenhouse emissions savings	359.8	162.7	339.8
Health benefits from reduced electricity generation and use of wood and gas	50.3	23.2	48.6
Society subtotal	**84.4**	**196.1**	**65.7**
TOTAL BENEFITS	**752.2**	**534.8**	**694.5**
NET PRESENT VALUES			
Accounting for energy benefits only	-994.5	-251.5	-651.3
Accounting for energy benefits + carbon benefits	-634.7	-88.8	-311.5
Accounting for energy benefits + carbon benefits + health benefits	-584.4	-65.6	-262.9
BCR (RATIO)			
Accounting for energy benefits only	0.26	0.58	0.32
Accounting for energy benefits + carbon benefits	0.53	0.85	0.67
Accounting for energy benefits + carbon benefits + health benefits	0.56	0.89	0.73

Note: Using a 7 per cent discount rate. Totals may not add up due to rounding.
Source: ACIL Allen.

Table H.3 Estimated lifetime (2022-2060) economy-wide costs and benefits of different policy options, present value ($M, 2021), Queensland

	Option A[a]	Option B[a]	Option A for Class 1 + Option B for Class 2[b]
COSTS			
Households - capital (resource) costs	498.1	210.9	248.7
Industry			
Training costs (incl. training time and training fees)	11.6	11.6	11.6
Redesign costs (volume builders)	7.1	7.1	7.1
Transition costs (custom builders)	21.1	21.1	21.1
Administrative costs (all buildings)	4.8	4.8	4.8
Government Costs	0.1	0.1	0.1
TOTAL COSTS	**542.9**	**255.6**	**293.4**
BENEFITS			
Households			
Electricity savings	141.5	61.9	92.9
Gas savings	2.3	2.0	0.8
LPG and firewood savings	0.2	0.2	0.2
Households offsetting amenity benefit	15.4	6.9	9.8
Household subtotal	**159.3**	**70.9**	**103.7**
Society			
Deferred/avoided generation, transmission and distribution investment for gas and electricity	9.5	4.5	5.4
Greenhouse emissions savings	81.3	35.2	54.2
Health benefits from reduced electricity generation and use of wood and gas	52.2	15.5	41.6
Society subtotal	**143.0**	**55.2**	**101.2**
TOTAL BENEFITS	**302.2**	**126.1**	**204.8**

	Option A[a]	Option B[a]	Option A for Class 1 + Option B for Class 2[b]
NET PRESENT VALUES			
Accounting for energy benefits only	-374.1	-180.2	-184.3
Accounting for energy benefits + carbon benefits	-292.8	-145.0	-130.1
Accounting for energy benefits + carbon benefits + health benefits	-240.6	-129.5	-88.6
BCR (RATIO)			
Accounting for energy benefits only	0.31	0.30	0.37
Accounting for energy benefits + carbon benefits	0.46	0.43	0.56
Accounting for energy benefits + carbon benefits + health benefits	0.56	0.49	0.70

[a] Results reflect the use of a heat pump water heater as the energy performance benchmark for Class 2 dwellings in Queensland and a gas instantaneous water heater benchmark for all other states.

[b] Results reflect the resetting of the energy performance benchmark for Class 2 dwellings in Queensland to be a gas instantaneous water heater (the same as for all other jurisdictions).

Note: Using a 7 per cent discount rate. Totals may not add up due to rounding.

Source: ACIL Allen.

Table H.4 Estimated lifetime (2022-2060) economy-wide costs and benefits of different policy options, present value ($M, 2021), South Australia

	Option A	Option B	Option A for Class 1 + Option B for Class 2
COSTS			
Households - capital (resource) costs	158.5	64.5	134.1
Industry			
Training costs (incl. training time and training fees)	3.6	3.6	3.6
Redesign costs (volume builders)	1.9	1.9	1.9
Transition costs (custom builders)	7.2	7.2	7.2
Administrative costs (all buildings)	1.4	1.4	1.4
Government Costs	0.0	0.0	0.0
TOTAL COSTS	**172.7**	**78.7**	**148.3**

	Option A	Option B	Option A for Class 1 + Option B for Class 2
BENEFITS			
Households			
Electricity savings	64.6	20.1	67.2
Gas savings	12.6	7.6	7.9
LPG and firewood savings	1.9	1.9	1.9
Households offsetting amenity benefit	6.8	3.1	6.6
Household subtotal	**86.0**	**32.7**	**83.5**
Society			
Deferred/avoided generation, transmission and distribution investment for gas and electricity	6.2	2.8	6.5
Greenhouse emissions savings	16.8	6.8	14.4
Health benefits from reduced electricity generation and use of wood and gas	7.2	2.9	7.0
Society subtotal	**30.2**	**12.6**	**28.0**
TOTAL BENEFITS	**116.1**	**45.3**	**111.5**
NET PRESENT VALUES			
Accounting for energy benefits only	-80.5	-43.2	-58.2
Accounting for energy benefits + carbon benefits	-63.7	-36.3	-43.8
Accounting for energy benefits + carbon benefits + health benefits	-56.5	-33.4	-36.8
BCR (RATIO)			
Accounting for energy benefits only	0.53	0.45	0.61
Accounting for energy benefits + carbon benefits	0.63	0.54	0.70
Accounting for energy benefits + carbon benefits + health benefits	0.67	0.58	0.75

Note: Using a 7 per cent discount rate. Totals may not add up due to rounding.
Source: ACIL Allen.

Table H.5 Estimated lifetime (2022-2060) economy-wide costs and benefits of different policy options, present value ($M, 2021), Western Australia

	Option A	Option B	Option A for Class 1 + Option B for Class 2
COSTS			
Households - capital (resource) costs	258.2	108.3	183.2
Industry			
Training costs (incl. training time and training fees)	5.7	5.7	5.7
Redesign costs (volume builders)	4.8	4.8	4.8
Transition costs (custom builders)	16.7	16.7	16.7
Administrative costs (all buildings)	3.3	3.3	3.3
Government Costs	0.1	0.1	0.1
TOTAL COSTS	**288.8**	**139.0**	**213.8**
BENEFITS			
Households			
Electricity savings	64.1	24.9	69.4
Gas savings	36.3	22.0	24.5
LPG and firewood savings	1.9	1.9	1.9
Households offsetting amenity benefit	7.7	4.6	6.9
Household subtotal	**109.9**	**53.3**	**102.6**
Society			
Deferred/avoided generation, transmission and distribution investment for gas and electricity	9.9	6.8	11.0
Greenhouse emissions savings	58.4	28.1	53.2
Health benefits from reduced electricity generation and use of wood and gas	28.6	11.3	28.2
Society subtotal	**96.9**	**46.2**	**92.4**
TOTAL BENEFITS	**206.8**	**99.5**	**195.0**

	Option A	Option B	Option A for Class 1 + Option B for Class 2
NET PRESENT VALUES			
Accounting for energy benefits only	-169.0	-78.9	-100.2
Accounting for energy benefits + carbon benefits	-110.6	-50.7	-47.0
Accounting for energy benefits + carbon benefits + health benefits	-82.0	-39.4	-18.8
BCR (RATIO)			
Accounting for energy benefits only	0.41	0.43	0.53
Accounting for energy benefits + carbon benefits	0.62	0.63	0.78
Accounting for energy benefits + carbon benefits + health benefits	0.72	0.72	0.91

Note: Using a 7 per cent discount rate. Totals may not add up due to rounding.
Source: ACIL Allen.

Table H.6 Estimated lifetime (2022-2060) economy-wide costs and benefits of different policy options, present value ($M, 2021), Tasmania

	Option A	Option B	Option A for Class 1 + Option B for Class 2
COSTS			
Households - capital (resource) costs	61.4	33.9	60.6
Industry			
Training costs (incl. training time and training fees)	1.1	1.1	1.1
Redesign costs (volume builders)	0.5	0.5	0.5
Transition costs (custom builders)	1.5	1.5	1.5
Administrative costs (all buildings)	0.3	0.3	0.3
Government Costs	0.0	0.0	0.0
TOTAL COSTS	**64.8**	**37.3**	**64.0**

	Option A	Option B	Option A for Class 1 + Option B for Class 2
BENEFITS			
Households			
Electricity savings	21.3	6.9	21.2
Gas savings	1.7	1.4	1.5
LPG and firewood savings	3.0	3.0	3.0
Households offsetting amenity benefit	2.4	1.2	2.3
Household subtotal	**28.3**	**12.5**	**28.1**
Society			
Deferred/avoided generation, transmission and distribution investment for gas and electricity	2.2	1.2	2.3
Greenhouse emissions savings	1.7	1.0	1.6
Health benefits from reduced electricity generation and use of wood and gas	1.6	1.6	1.6
Society subtotal	**5.5**	**3.8**	**5.4**
TOTAL BENEFITS	**33.8**	**16.3**	**33.5**
NET PRESENT VALUES			
Accounting for energy benefits only	-34.2	-23.6	-33.6
Accounting for energy benefits + carbon benefits	-32.6	-22.6	-32.0
Accounting for energy benefits + carbon benefits + health benefits	-31.0	-21.0	-30.4
BCR (RATIO)			
Accounting for energy benefits only	0.47	0.37	0.47
Accounting for energy benefits + carbon benefits	0.50	0.39	0.50
Accounting for energy benefits + carbon benefits + health benefits	0.52	0.44	0.52

Note: Using a 7 per cent discount rate. Totals may not add up due to rounding.
Source: ACIL Allen.

Table H.7 Estimated lifetime (2022-2060) economy-wide costs and benefits of different policy options, present value ($M, 2021), Northern Territory

	Option A	Option B	Option A for Class 1 + Option B for Class 2
COSTS			
Households - capital (resource) costs	65.5	27.2	57.9
Industry			0.0
Training costs (incl. training time and training fees)	0.4	0.4	0.4
Redesign costs (volume builders)	0.2	0.2	0.2
Transition costs (custom builders)	0.5	0.5	0.5
Administrative costs (all buildings)	0.2	0.2	0.2
Government Costs	0.0	0.0	0.0
TOTAL COSTS	**66.7**	**28.5**	**59.2**
BENEFITS			
Households			
Electricity savings	48.5	15.2	46.4
Gas savings	0.0	0.0	0.0
LPG and firewood savings	0.0	0.0	0.0
Households offsetting amenity benefit	3.0	1.3	2.7
Household subtotal	**51.6**	**16.5**	**49.1**
Society			
Deferred/avoided generation, transmission and distribution investment for gas and electricity	3.6	1.8	3.3
Greenhouse emissions savings	13.0	4.1	12.5
Health benefits from reduced electricity generation and use of wood and gas	0.3	0.1	0.3
Society subtotal	**17.0**	**5.9**	**16.1**
TOTAL BENEFITS	**68.5**	**22.4**	**65.2**

	Option A	Option B	Option A for Class 1 + Option B for Class 2
NET PRESENT VALUES			
Accounting for energy benefits only	-11.5	-10.2	-6.7
Accounting for energy benefits + carbon benefits	1.5	-6.1	5.8
Accounting for energy benefits + carbon benefits + health benefits	1.8	-6.0	6.0
BCR (RATIO)			
Accounting for energy benefits only	0.83	0.64	0.89
Accounting for energy benefits + carbon benefits	1.02	0.79	1.10
Accounting for energy benefits + carbon benefits + health benefits	1.03	0.79	1.10

Note: Using a 7 per cent discount rate. Totals may not add up due to rounding.
Source: ACIL Allen.

Table H.8 Estimated lifetime (2022-2060) economy-wide costs and benefits of different policy options, present value ($M, 2021), ACT

	Option A	Option B	Option A for Class 1 + Option B for Class 2
COSTS			
Households - capital (resource) costs	79.7	27.5	39.8
Industry		0.0	
Training costs (incl. training time and training fees)	0.9	0.9	0.9
Redesign costs (volume builders)	0.9	0.9	0.9
Transition costs (custom builders)	1.6	1.6	1.6
Administrative costs (all buildings)	0.6	0.6	0.6
Government Costs	0.0	0.0	0.0
TOTAL COSTS	**83.8**	**31.6**	**43.8**

	Option A	Option B	Option A for Class 1 + Option B for Class 2
BENEFITS			
Households			
Electricity savings	20.0	10.2	18.7
Gas savings	12.0	4.4	4.8
LPG and firewood savings	0.2	0.2	0.2
Households offsetting amenity benefit	3.2	1.6	2.3
Household subtotal	**35.4**	**16.3**	**26.0**
Society			
Deferred/avoided generation, transmission and distribution investment for gas and electricity	2.2	2.5	2.6
Greenhouse emissions savings	12.3	5.2	8.0
Health benefits from reduced electricity generation and use of wood and gas	0.6	0.3	0.4
Society subtotal	**15.1**	**8.0**	**11.1**
TOTAL BENEFITS	**50.5**	**24.3**	**37.0**
NET PRESENT VALUES			
Accounting for energy benefits only	-46.2	-12.9	-15.3
Accounting for energy benefits + carbon benefits	-33.9	-7.6	-7.3
Accounting for energy benefits + carbon benefits + health benefits	-33.3	-7.3	-6.8
BCR (RATIO)			
Accounting for energy benefits only	0.45	0.59	0.65
Accounting for energy benefits + carbon benefits	0.60	0.76	0.83
Accounting for energy benefits + carbon benefits + health benefits	0.60	0.77	0.84

Note: Using a 7 per cent discount rate. Totals may not add up due to rounding.
Source: ACIL Allen.

I Window and glazing benefits

This appendix discusses the benefits of windows and glazing. Notably, the information in this section was mainly sourced from AGWA's submission to the CRIS, which provided a detailed literature review of these benefits.

Glazing has notable non-energy related benefits in areas ranging from happiness and wellbeing to quality of life, healthcare, mental health, learning, and productivity. More specifically, by improving access to daylight in buildings, glazing links residents to the outside world through an external visual connection and provides greater access to fresh air and ventilation, while also providing an important aesthetic (i.e., cultural) function.[5]

The impact of exposure to daylight on happiness and wellbeing is confirmed by research, which finds that a resident's sense of wellbeing is enhanced through access to views of the natural environment, partly due to the influence of natural light cycles on circadian rhythms.[6] The absence of daylight, consequently, has profoundly negative effects on a person's sense of wellbeing.

The quality of life impact of large windows on residential welfare is an observed phenomenon, with a body of research confirming that proximity to and the characteristics of windows are positively regarded, affect job satisfaction, and reduce negatively regarded feelings of enclosure.[7] Importantly, higher glazing ratios are associated with better daylight factors in new buildings.[8]

Access to daylight affects outcomes in healthcare, particularly when those outcomes are related to stress. Research has found that patients had relatively shorter lengths of stay when located in sunnier, drier, and warmer medical centres, and had lower rates of mortality, indicating a relationship between daylight exposure and positive healthcare outcomes.[9] Similarly, access to daylight affects mental health by reducing the level of stress associated with feelings of 'window lessness,' which are often perceived as harmful to wellbeing.[10]

Daylight, along with other spatial design features, is an important factor contributing to learning outcomes. The level and source of lighting determines the visual environment in which learning activities take place, and studies have consistently shown that access to natural lighting through windows is associated with faster progression in areas such as mathematics and reading comprehension, results that are observed in multiple studies across different schools, curriculums,

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[5] Australian Glass and Window Association (2021, p. 1). Window and Glazing Benefits Literature Review.

[6] Ibid (p. 1).

[7] Ibid (p. 2).

[8] Clarke, J (2014, p. 20). CSR House Technique Australian Daylight Benchmarks.

[9] Australian Glass and Window Association (2021, pp. 2-3). Window and Glazing Benefits Literature Review.

[10] Ibid (p. 3).

and building designs.[11] This is to the extent that the relationship between access to daylight is clearly a significant factor influencing educational attainment. Consequently, minimum standards will promote positive outcomes in this area, as they affect spatial elements of building design, particularly in relation to the visual environment.

Productivity is also affected by access to daylight. The value of windows is clearly demonstrated by research findings related to job satisfaction and other determinants of productivity. There exists a strong preference for working near windows, with the absence of a window being identified by thirty five per cent of employees questioned as part of a study as their ‘major concern associated with workplace productivity’,[12] and a questionnaire in 1967 finding that 96 per cent of respondents preferred to work under natural lighting.[13] More recent analysis in 2003 found that employee performance is positively related to daylight illumination levels.[14] Cumulatively, these results show that providing lighting through glazing is both conducive to productivity and highly valued in the workplace.

Promoting glazing efficiency through minimum requirements is an important measure that will reduce the energy usage of structures while yielding consumer benefits that are not limited to cost savings. In fact, as has been shown, a range of important outcomes are positively influenced by spatial design features, including those of windows.

[11] Ibid (pp. 3-4).

[12] Collins, B. (1990). The Psychological Aspects of Lighting: A Review of the Work of CIE TC3.16.

[13] Markus, T.A. (1967). The Significance of Sunshine and View for Office Workers.

[14] Heschong (2003). Windows and Offices: A Study of Worker Performance and the Indoor Environment.

J Overview of ACIL Allen energy

This Appendix provides an overview of two of our energy market models that were used to provide inputs to our cost benefit analysis:

— PowerMark, which simulates the wholesale electricity market
— GasMark, which simulates the wholesale gas market.

J.1 PowerMark

PowerMark has been developed over the past 20 years in parallel with the development of the National Electricity Market (NEM). PowerMark is a complex model with many unique and valuable features. It provides insights into:

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

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

In accordance with the NEM's market design, the price at any one period is the cost of the next increment of generation in each region (the shadow or dual price within the LP). The LP seeks to minimise the aggregate cost of generation for the market as a whole, while meeting regional demand and other network constraints. Figure J.1 is a simplified diagrammatic representation of the model and its methods of combining input data from the supply and demand modules to produce a price and dispatch result for each region and power station for each period.

PowerMark is very flexible. Additional elements, such as regions, interconnectors, generators or loads can be easily added and their characteristics varied through time. PowerMark has been applied to several different market designs — gross pools, net pools, regional and nodal structures.

A distinctive feature of PowerMark is the inclusion of a portfolio optimisation module.[15] This component which is almost always employed when modelling energy-only markets, allows selected portfolios to seek to maximise net revenue positions (taking into consideration contracts for differences) for each period. These modified generator offers are then resubmitted to the settlement engine to determine prices and dispatch levels. Each period is iterated until a convergence point (based on Nash-Cournot / Supply Function equilibrium theory) is found.

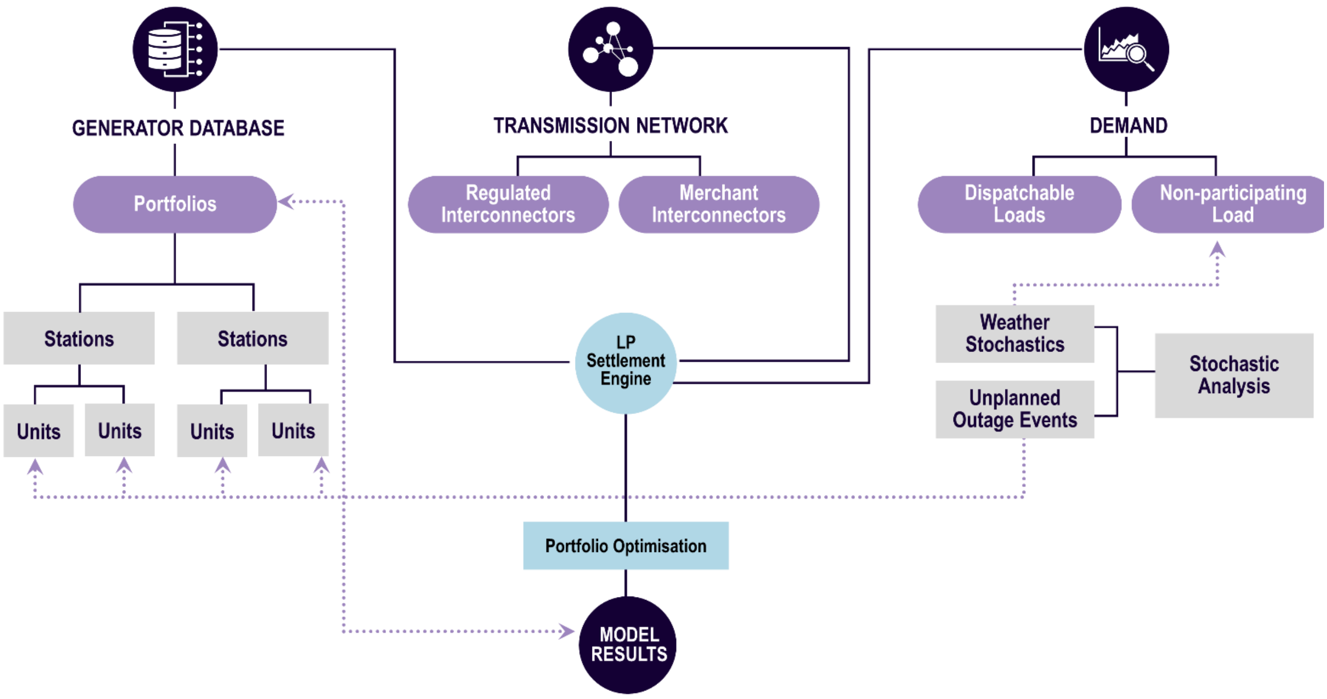
The benefits of the optimisation module are twofold:

— portfolios structure their generation offers in an economically rational way. From past experience, this optimisation process generates strategies which align with the behavioural reality in the marketplace; and
— second-round effects from fundamental changes to the market — such as a policy change, addition or closure of generators, transmission augmentation or creation of additional regions, can automatically be incorporated without imposing explicit constraints or directions for incumbents.

PowerMark can be configured to run at varying time intervals — from 5 minutes (288 period days) through to 180 minutes (8 period days). Typically, the model is run hourly or half-hourly to meet client requirements and establish a reasonable price resolution.

[15] ACIL Allen's energy market models are economic-based models, while AEMO uses a resource-based model for planning and forecasting. As a consequence, the outputs from ACIL Allen's models do not necessarily align with the outputs from AEMO's planning and forecasting models. The outputs from ACIL Allen's models depend on the various inputs and assumptions, which are updated periodically as new information becomes available.

Figure J.1 PowerMark model structure



Source: ACIL Allen

J.2 GasMark

GasMark Global (GMG) is a generic gas modelling platform developed by ACIL Allen. GMG has the flexibility to represent the unique characteristics of gas markets across the globe, including both pipeline gas and LNG. Its potential applications cover a broad scope — from global LNG trade, through to intra-country and regional market analysis. GasMark Global Australia (GMG Australia, or GasMark) is an Australian version of the model which focuses specifically on the Australian market (including both Eastern Australia and Western Australia), but which has the capacity to interface with international LNG markets.

The model can be specified to run at daily, monthly, quarterly or annual resolution over periods up to 30 years.

J.2.1 Settlement

At its core, GasMark is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to ‘arks’ within a network model).

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. The objective function of this solution, which is well established in economic theory[16], consists of three terms:

— the integral of the demand price function over demand; minus
— the integral of the supply price function over supply; minus
— the sum of the transportation, conversion and storage costs.

The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price.

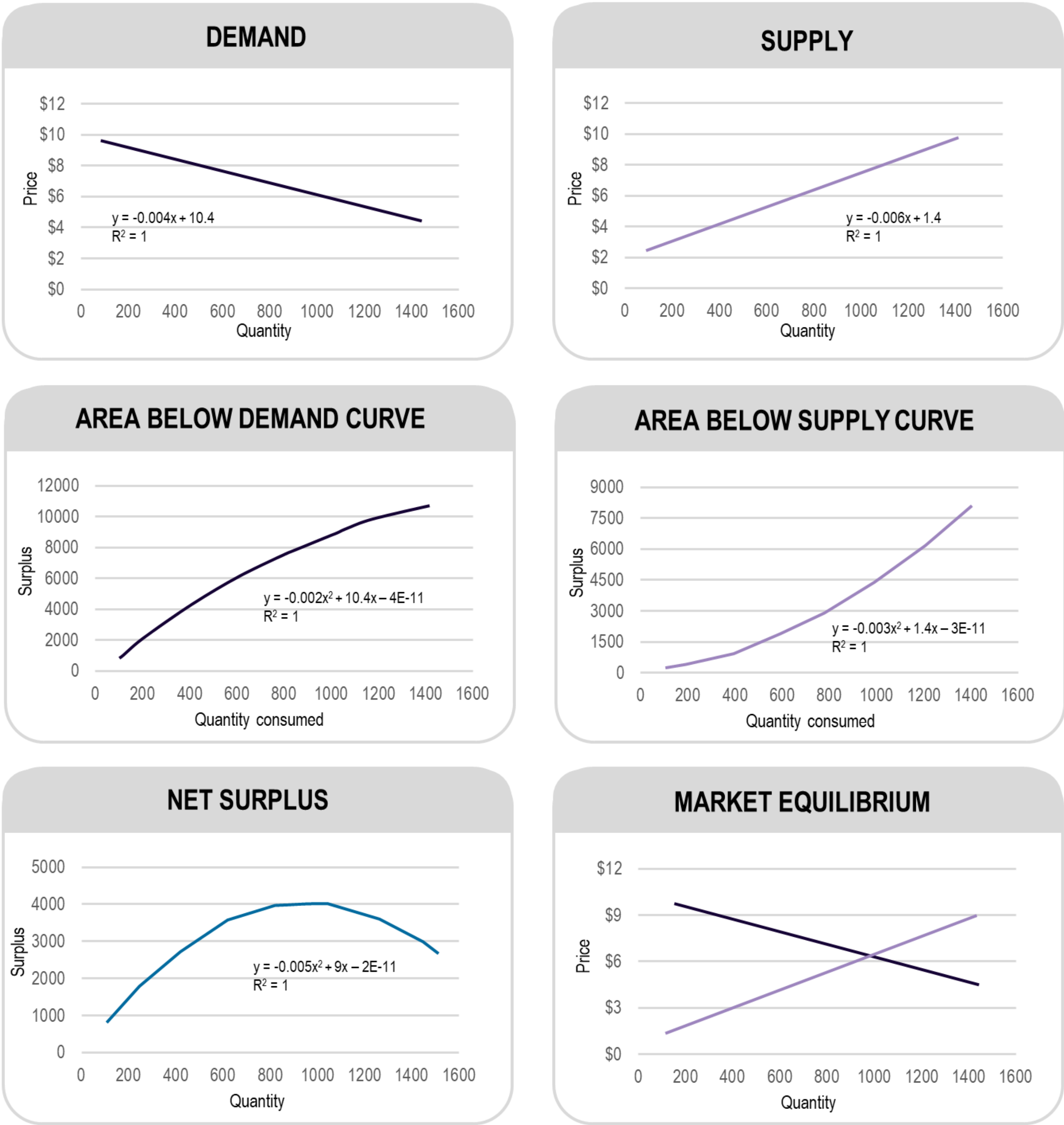
Figure J.2 seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of the figure show simple linear demand and supply functions for a market. The figures in the middle of Figure J.2 show the integrals of these demand and supply functions, which represent the areas under the demand and supply curves. These are equivalent to the consumer and producer surpluses at each price point along the curve. The figure on the bottom left shows the summation of the consumer and producer surplus, with a maximum at a quantity of 900 units. This is equivalent to the equilibrium quantity when demand and supply curves are overlayed as shown in the bottom right figure.

The distinguishing characteristic of spatial price equilibrium models lies in their recognition of the importance of space and transportation costs associated with transporting a commodity from a supply source to a demand centre. Since gas markets are interlinked by a complex series of transportation paths (pipelines, shipping paths) with distinct pricing structures (fixed, zonal or distance based), GMG Australia also includes a detailed network model with these features.

Spatial price equilibrium models have been used to study problems in a number of fields including agriculture, energy markets, mineral economics, as well as in finance. These perfectly competitive partial equilibrium models assume that there are many producers and consumers involved in the production and consumption, respectively, of one or more commodities and that as a result the market settles in an economically efficient fashion. Similar approaches are used within gas market models across the world.

[16] The theoretical framework for the market solution used in GMG is attributed to Nobel Prize winning economist Paul Samuelson.

Figure J.2 Simplified example of market equilibrium and settlement process



Source: ACIL Allen.

J.2.2 Data inputs

The user can establish the level of detail by defining a set of supply regions, customers, demand regions, pipelines and LNG facilities. These sets of basic entities in the model can be very detailed or aggregated as best suits the objectives of the user. A 'pipeline' could represent an actual pipeline or a pipeline corridor between a supply and a demand region. A supplier could be a whole gas production basin aggregating the output of many individual fields, or could be a specific producer in a smaller region. Similarly, a demand point could be a single industrial user or an aggregation of small consumers such as the residential and commercial users typically serviced by energy utility companies.

The inputs to GMG Australia can be categorised as follows:

- **Existing and potential new sources of gas supply**: these are characterised by assumptions about available reserves, production rates, production decline characteristics, and minimum price expectations of the producer. These price expectations may be based on long-run marginal costs of production or on market expectations, including producer's understandings of substitute prices.
- **Existing and potential new gas demand**: demand may relate to a specific load such as a power station, or fertiliser plant. Alternatively, it may relate to a group or aggregation of customers, such as the residential or commercial utility load in a particular region or location. Loads are defined in terms of their location, annual and daily gas demand including daily demand profiles, and price tolerance.
- **Existing, new and expanded transmission pipeline capacity**: pipelines are represented in terms of their geographic location, physical capacity (which may vary over time), flow characteristics (uni-directional or bi-directional) and tariffs.
- **Existing, new and expanded gas storage facilities**: Storage is represented in terms of geographic location, physical capacity (which may vary over time), injection and withdrawal rates, storage efficiency and tariffs.

Existing and potential new LNG facilities: LNG facilities include liquefaction plants, regasification (receiving) terminals and assumptions regarding shipping costs and routes. LNG facilities play a similar role to pipelines in that they link supply sources with demand. LNG plants and terminals are defined at the plant level and require assumptions with regard to annual throughput capacity and tariffs for conversion.

K Wholesale electricity market modelling – assumptions

This Appendix describes the assumptions that have been used in the wholesale electricity market modelling.

The scenarios modelled are as set out in Table K.1.

Table K.1 Scenarios modelled

Scenario	Description
Reference case	Standard ACIL Allen reference case as at December 2021
Scenario 1	Class 1 buildings – NCC 2022 proposal, Option A Class 2 buildings – NCC 2022 proposal, Option B (no solar PV)
Scenario 2	As per scenario 1 with twice as much solar PV capacity installed

The assumptions that have been specifically made for scenarios 1 and 2 are described in Appendix K.2.3. All other assumptions are the same as for the reference case.

K.1 Macro assumptions

Inflation and foreign exchange assumptions are used in the escalation of nominal input costs for generators (fuel, variable O&M, capital costs for new entrants etc.).

The Brent crude oil price and the Newcastle FOB coal price are input assumptions for ACIL Allen's gas and coal price projections for the NEM, respectively. Western Australian-specific assumptions are used to project the gas and coal prices for the SWIS.

Inflation

ACIL Allen undertakes the market modelling in nominal terms and therefore uses an explicit inflation assumption to escalate cost inputs relative to this index. Inflation is measured as the change in the Consumer Price Index (CPI) on an annual basis. The assumption used throughout is 2.5 per cent per annum, which corresponds to the mid-point of the Reserve Bank inflation target range.

Foreign exchange rate

The Australian dollar is assumed to hold constant at the long-term average of 0.75 USD/AUD throughout the projection period. The basis of this assumption is that the Australian dollar is a commodity currency which tracks reasonably closely with commodity prices in the long term.

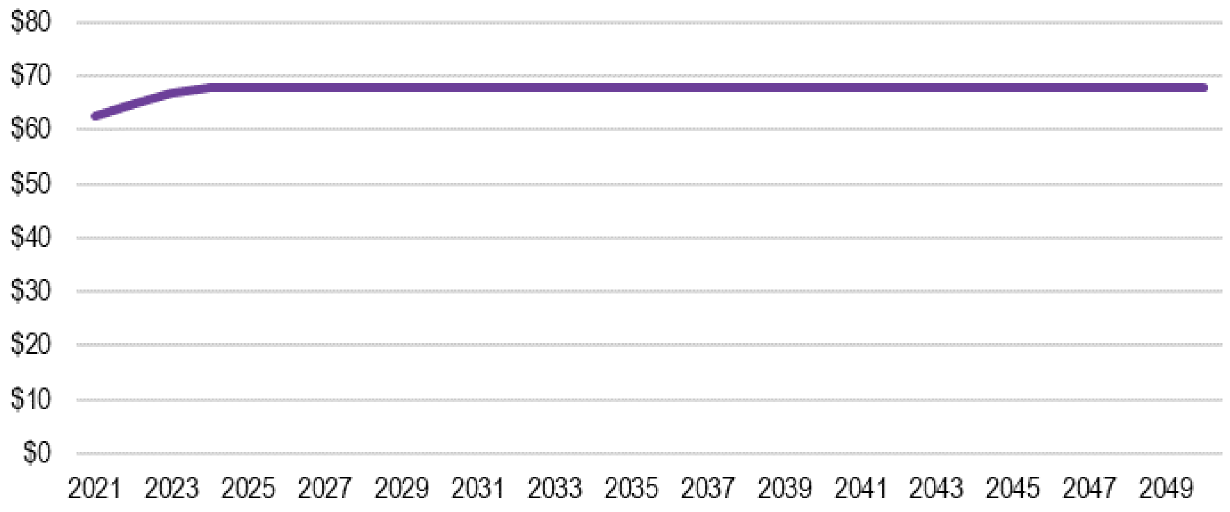
Brent crude oil price

The domestic gas market is linked to the international market through the LNG export plants in Gladstone. As a result, movements in global oil prices have an important influence on domestic gas prices.

The principal pricing model for LNG contracts in the Asia Pacific region is oil-linked pricing based around the Japanese Customs-cleared Crude (JCC) price, a close proxy to the Brent crude price (see Figure K.1).

Fluctuation in oil prices has a direct flow-on effect to the price of LNG produced in Australia because most long-term LNG contracts (including those written by the three Gladstone LNG projects) have a formulaic link to the JCC oil price.

Figure K.1 Assumed Brent crude oil price ($US/barrel, real 2021)



Source: ACIL Allen September 2021 quarterly gas price report

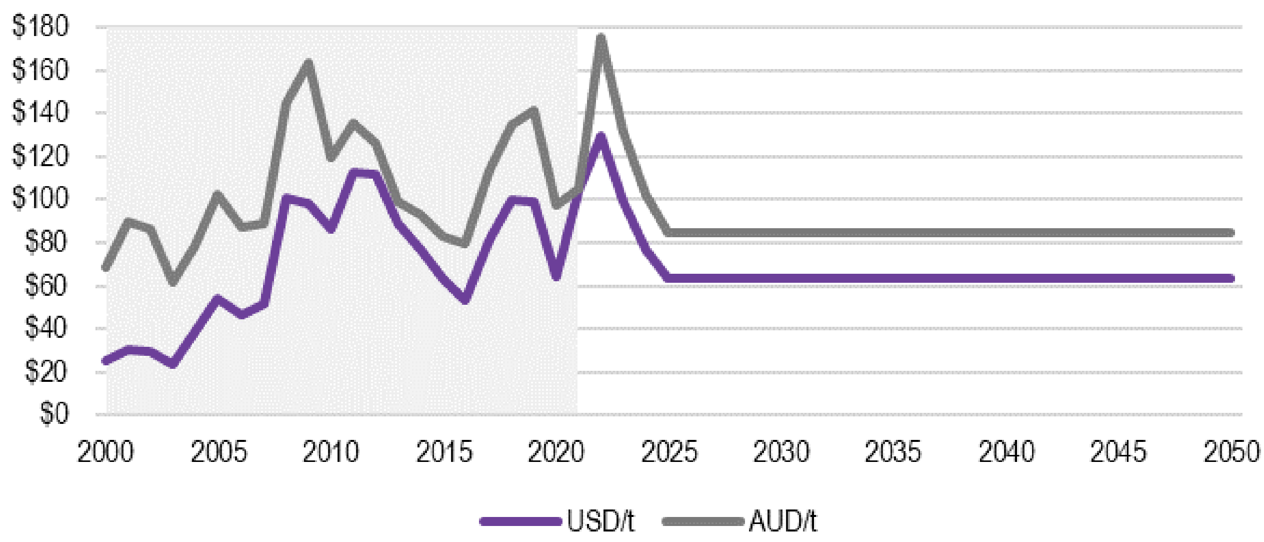
Export coal price

The Newcastle Free on Board (FOB) price for thermal coal is an important consideration in the price formation for all new coal contracts in New South Wales and for some in Queensland. The projection of these prices underlies the projected future export parity value of the Run of Mine (ROM) coal at each location which is an important consideration in setting the likely delivered price into local power stations.

Export prices declined dramatically during the second half of 2019 and early 2020 as supply growth outpaced demand – returning coal prices to levels more reflective of the marginal cost of supply. Since late 2020 export prices have increased in response to stronger Asian demand, which is driven by the region's economic recovery after COVID-19's impacts in 2020 as well as cold winter conditions. Supply from some producers had been curtailed in 2020 in response to the low export prices, resulting in a tighter thermal coal market.

As illustrated in Figure K.2, the reference case assumes that export coal prices will peak at USD$76/t in real 2021 terms in 2022, before falling to USD$62/t in real 2021 terms by 2024 and remaining at this level for the remainder of the projection horizon.

Figure K.2 Assumed Newcastle FOB prices ($/tonne, real 2021), 2000 to 2050



Source: ACIL Allen

K.2 Electricity demand

Regional annual energy and peak demand are important inputs to wholesale energy market modelling. *PowerMark* models the segment of the market to be satisfied by the NEM and in the SWIS, that is, by scheduled and semi-scheduled generation. This is the underlying demand less rooftop PV output, plus electric vehicle charging requirements and behind-the-meter storage round trip losses.

K.2.1 Reference case, NEM

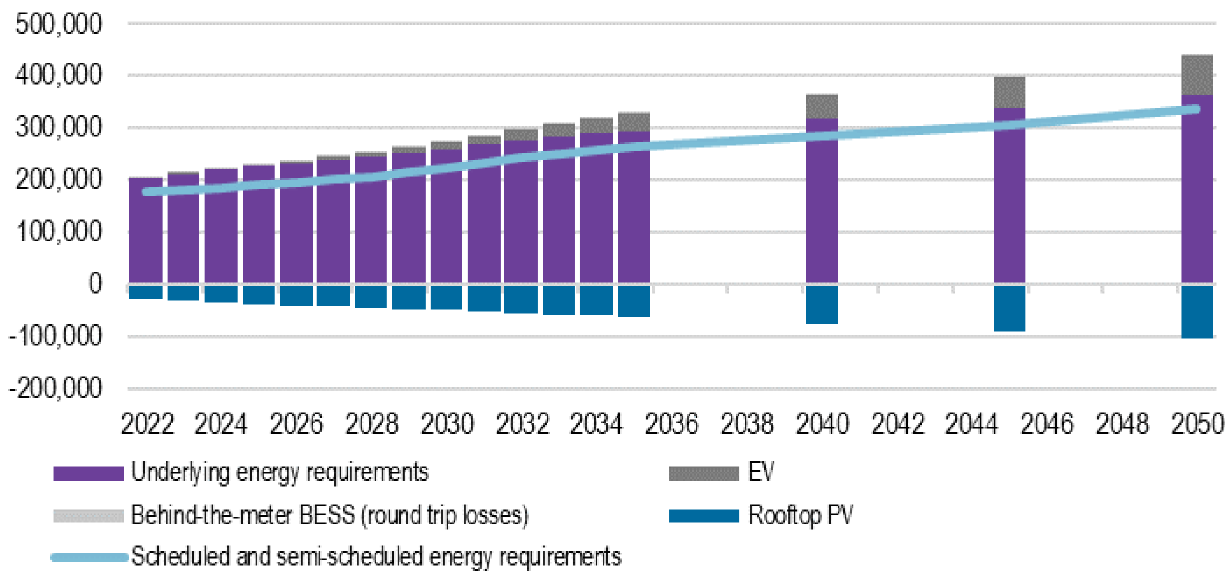
The reference case for the NEM uses as a starting point the official projection of regional summer and winter peak demands and annual energy published in the Draft 2022 Integrated System Plan (ISP) by the Australian Energy Market Operator (AEMO) in August 2021. The demand projection is based on the Steady Progress scenario and the 50 per cent probability of exceedance (POE50) level peak summer and winter peak demands.

To these projections ACIL Allen has exercised its judgement and made the following adjustments:[17]

1. ACIL Allen has undertaken and adopted its own projection of the uptake of **rooftop solar PV** and **behind-the-meter storage** for both the residential and commercial sector, which are internally consistent with other assumptions adopted in the reference case (such as exchange rates, capital costs, network tariffs etc.).
2. Though ACIL Allen has adopted the projected uptake of **electric vehicles** as forecast by AEMO in its Draft 2020 ISP Strong Electrification scenario, we have used our own charging profiles in our modelling. This is further explained in Appendix L.
3. Electrification is a key part of the underlying demand in AEMO's demand projections. Since we expect a higher electrification rate than assumed under AEMO's Draft 2022 ISP Steady Progress scenario, we have replaced the annual electrification demand in the Steady Progress scenario with the annual electrification demand from the Strong Electrification scenario.

The resulting NEM-wide energy requirements are shown in Figure K.3

Figure K.3 Assumed NEM energy requirements (GWh, gross), 2022 to 2050

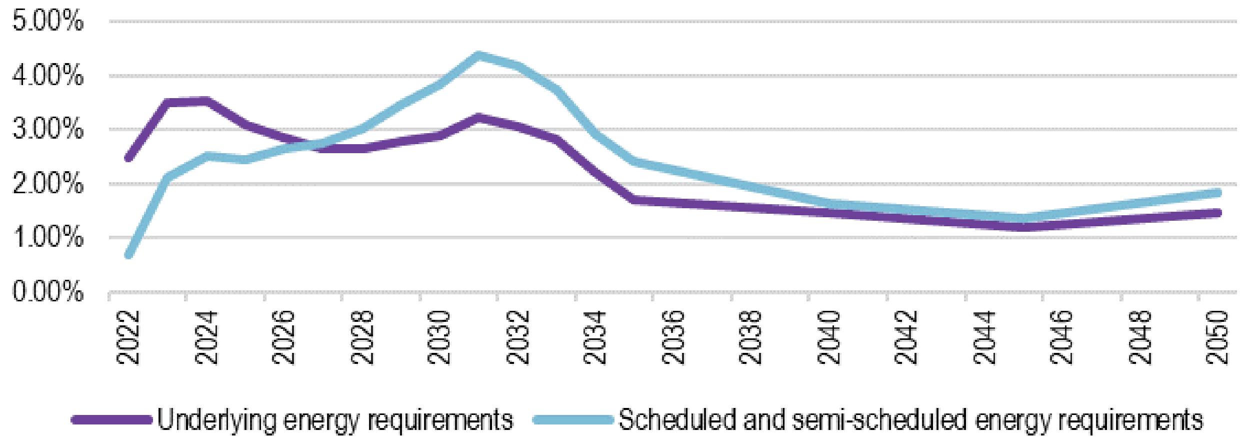


Source: ACIL Allen

There is a strong growth in energy requirements from 2030 onwards as a result of higher EV uptake and electrification. Rooftop PV uptake shows a steady growth as well, but does not offset the overall NEM-wide growth of scheduled and semi-scheduled energy requirements. By 2031 NEM-wide scheduled and semi-scheduled demand reaches a growth rate of 4.4 per cent as shown in Figure K.4. After 2031 this growth rate decreases and stabilises around 1.5 per cent by 2040.

[17] ACIL Allen also deducts an estimate of significant non-scheduled generation from AEMO's operational demand forecast to arrive at a scheduled and semi-scheduled projection (the segment of the market supplied by the NEM).

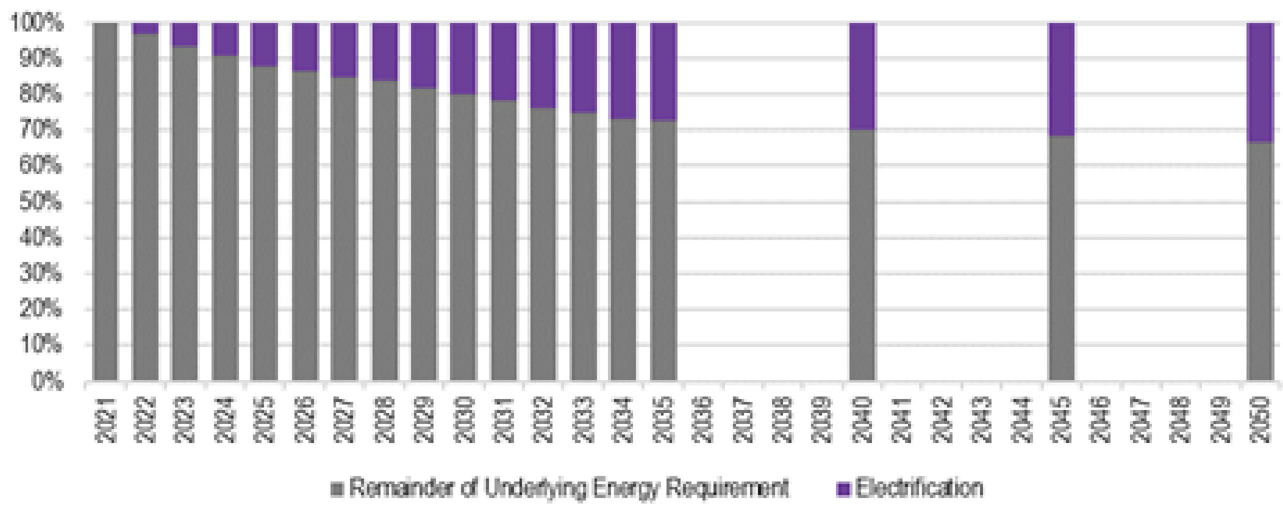
Figure K.4 Annual year on year growth in assumed NEM energy requirements (%), 2022 to 2050



Source: ACIL Allen

The continued increase of underlying energy requirements is partly attributed to an increasing rate of NEM-wide electrification. Figure K.5 shows how the percentage of electrification as part of total underlying demand rapidly increases over time. By 2050 33 per cent of the underlying demand is attributed to electrification. This underscores the scale of the impact of electrification on the NEM.

Figure K.5 Percentage of electrification as part of total underlying energy requirement, 2021 to 2050

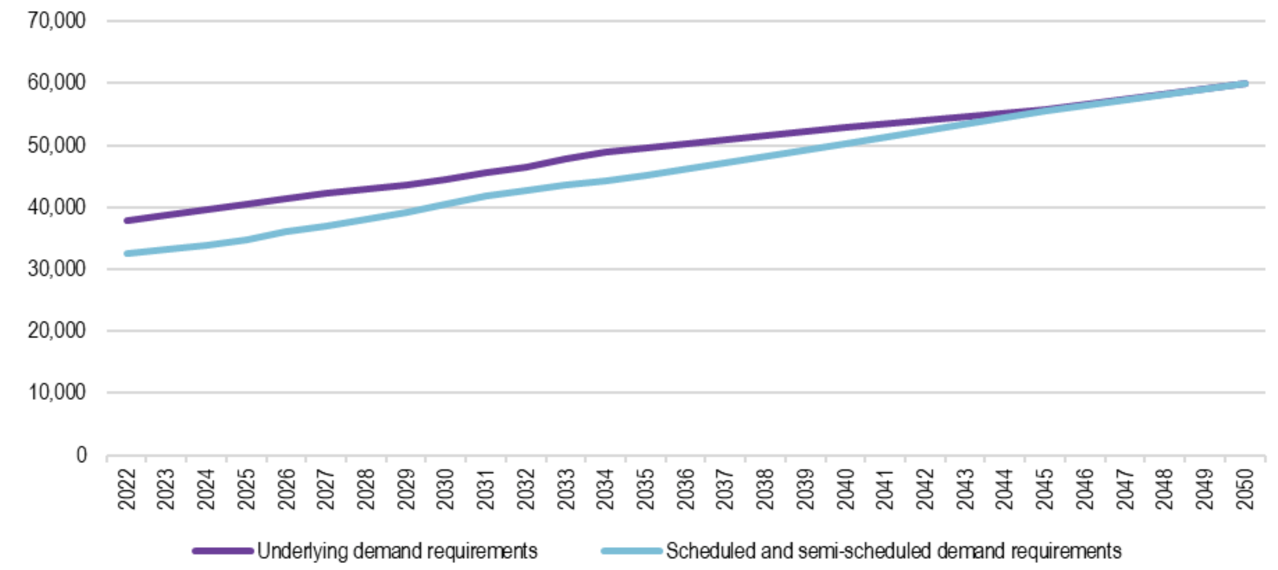


Source: ACIL Allen

Peak demand typically occurs in the summer months in all regions of the NEM except for Tasmania. However, the shift of natural gas equipment for heating, hot water and cooking to electricity, results in higher demand during winter, particularly in Victoria and New South Wales. Therefore, peak demand in Victoria shifts from summer to winter peak from 2025 onwards and in NSW peak demand shifts from summer to winter peak from 2045 onwards.

At the beginning of the projection period the peak demand is about 5,000 MW lower than what it would be if there were no rooftop PV installations (Figure K.6). This difference reduces over time which is largely due to an assumed increase in EV and battery charging demand.

Figure K.6 Assumed NEM wide peak demand (MW, gross), 2022 to 2050



Source: ACIL Allen

Further details of the demand and energy assumptions are set out in, as are our projections of the uptake of rooftop solar PV and behind-the-meter storage.

The aluminium smelters in the NEM are assumed to continue their operations as per AEMO's Steady Progress scenario forecast. Our view on their continued operations is set out in further detail in Appendix L.

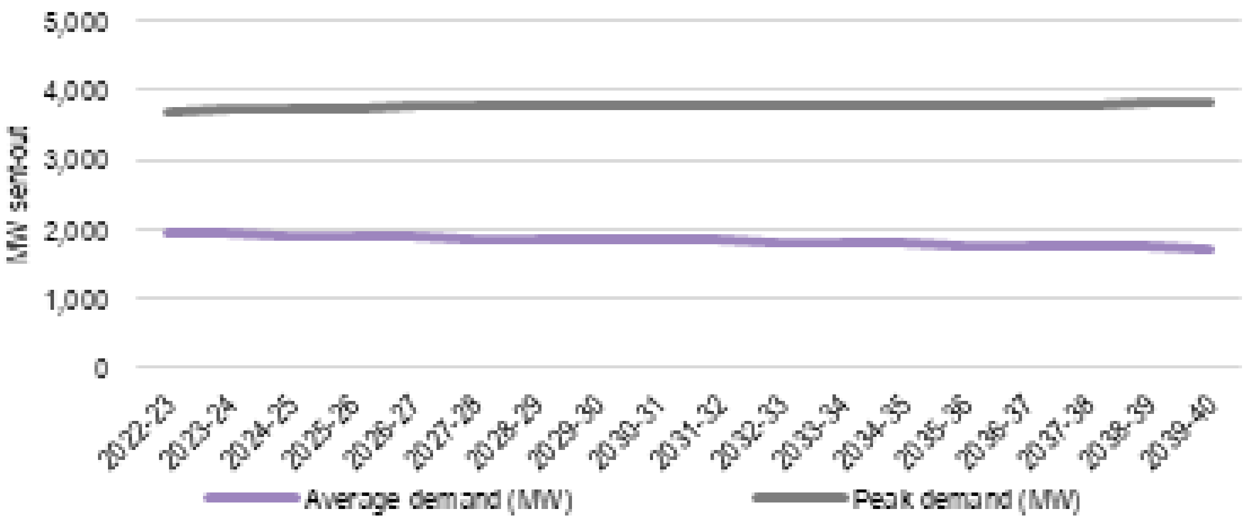
K.2.2 Reference case, Western Australia

The reference case for Western Australia uses as a starting point the official forecast of peak demands and annual energy as published in the 2021 Electricity Statement of Opportunities (ESOO) report as prepared by AEMO, which was released in June 2021. The expected economic growth scenario is used for energy and 50% POE for peak demand.

The ESOO projects energy and demand values to 2030-31. ACIL Allen has extrapolated these values based on the modelled relationships between each of the component's observable in the ESOO forecast.

Figure K.7 shows the projected peak and average demand for centralised generation (i.e. net of rooftop solar PV and behind the meter batteries) in the SWIS over the period to 2039-40.

Figure K.7 Projection of grid demand in the SWIS, 2022-23 to 2039-40



Source: ACIL Allen

ACIL Allen accounts for the impacts of solar PV at the half-hourly level using a specific output profile for rooftop solar PV in the SWIS. The AEMO forecast is 'grossed-up' for the impacts of solar PV on energy and peak demands, with solar PV then deducted from the grown trace at a half-hourly resolution. This ensures the impact of solar PV upon peak demand and the daily shape is properly accounted for as installed capacity grows.

The Reference case has peak grid demand rising slightly from 3,709 MW in 2022-23 to 3,826 MW in 2039-40 (3% total increase). By comparison, average demand is projected to fall from 17,032 GWh to 15,026 GWh over the same period (a 12% reduction).

These values align closely with the AEMO 2021 ESOO medium economic growth and P50 peak demand forecasts.

ACIL Allen adopts the EV energy and behind the meter battery projections from the AEMO 2021 ESOO (which extends to 2031) and extrapolates these through to 2040.

K.2.3 Scenarios 1 and 2

The inputs to the wholesale energy market modelling for scenario 1 are informed by:

— modelling by Energy Efficiency Strategies of the impact of NCC 2022 on an average building by classification, by jurisdiction and by climate zone

— modelling by ACIL Allen to aggregate the building level impacts (housing stock model).

For each building classification, jurisdiction and climate zone, the building level model assesses the impact of various BAU scenarios and pathways to comply with the NCC 2022 on:

- energy consumption by fuel type and purpose:
  - heating – peak electricity, off peak electricity, gas, LPG, wood
  - cooling – peak electricity
  - water heating – peak electricity, off peak electricity, gas
  - lighting – peak electricity
  - pool – peak electricity
  - spa – peak electricity
- peak electricity demand – summer, winter
- solar PV
  - size of PV system (maximum)
  - size of PV system (average)
  - electricity generated
  - electricity exported.

The building-level impacts are aggregated based on:

- assumptions about the pathways that different buildings are likely to follow to comply with the new requirements, based on their characteristics under the BAU (e.g. the compliance pathway for buildings currently built with PV in the baseline would be different to those buildings that are not being built with PV)
- assumptions about the proportion of new homes installing PVs at time of construction under the BAU
- projections of the number of new buildings that will be impacted by NCC 2022.

A 10 per cent rebound factor has been assumed. [18]

Solar PV assumptions

The assumptions for the uptake of solar PV under scenario 1 (Option A) are described in Section 5.2.1.

Inputs to the energy market modelling

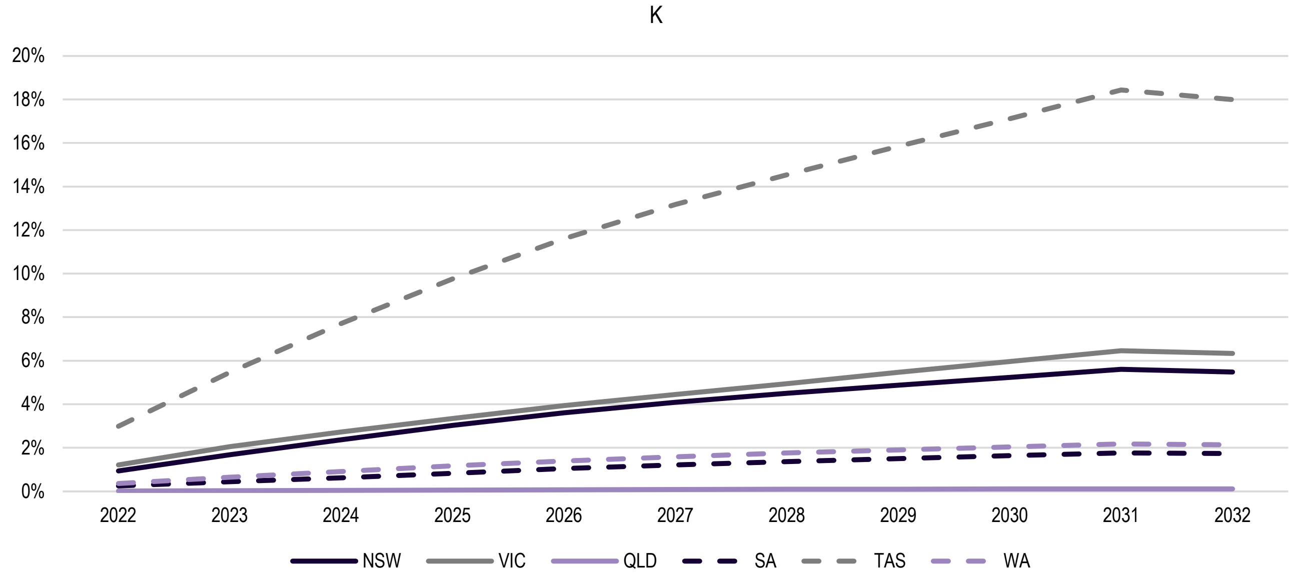
The inputs to the energy market modelling for scenario 1, derived from the housing stock model, are set out in Table K.2. The impacts of the NCC 2022 are set out for the years 2022-33 only. From 2034, the impacts are expected to decline in line with the asset life of the measures.

The extent to which the electricity consumption increases or decreases under NCC 2022 is a function of the amount of fuel switching, and the increases in peak demand are not material.

[18] It is assumed that consumers will reduce their energy usage by 90 per cent of the theoretical reduction possible. The remaining 10 per cent will be used to power additional appliances or equipment, or to increase the comfort level of the building.

Figure K.8 illustrates the PV capacity that is estimated to be installed under the proposed NCC 2022 (scenario 1) compared to AEMO's projections under the steady progress scenario, in the case of the NEM[19], and the expected case for Western Australia. The total increase in solar PV capacity estimated to be installed under the proposed NCC 2022 relative to the BAU[20] in 2030-31 is minimal in Queensland, around 2 per cent higher in South Australia and Western Australia, around 5-6 per cent higher in New South Wales and Victoria, and around 17 per cent higher in Tasmania. The additional PV capacity is projected to be minimal in Queensland.

Figure K.8 New PV installations as a proportion of AEMO's steady progress (NEM) and expected case (Western Australia) projections, scenario 1, 2022 to 2032



Source: ACIL Allen analysis based on AEMO's 2021 Inputs and assumptions workbook (NEM), and AEMO's 2021 ESOO (Western Australia)

[19] AEMO's projections are similar under the steady progress and progressive change scenarios.

[20] AEMO's steady progress scenario for the NEM and the expected case for Western Australia.

Table K.2 Inputs to energy market modelling, scenario 1, 2022 to 2033

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cumulative change in peak electricity consumption (MWh)												
NSW	-25,390	-50,890	-78,772	-109,090	-140,042	-170,017	-198,960	-226,964	-254,180	-280,661	-280,380	-280,097
VIC	-13,101	-25,862	-39,238	-53,982	-70,448	-87,335	-103,891	-119,813	-135,230	-150,451	-150,218	-149,993
QLD	-3,692	-7,506	-11,732	-16,365	-21,118	-25,638	-29,915	-34,134	-38,306	-42,448	-42,350	-42,250
SA	-3,217	-6,303	-9,567	-13,518	-17,897	-21,953	-25,725	-29,412	-33,026	-36,503	-36,409	-36,320
WA	-5,969	-12,308	-19,153	-26,427	-34,018	-41,483	-48,820	-56,107	-63,308	-70,525	-69,888	-69,215
TAS	-1,429	-2,837	-4,320	-5,921	-7,623	-9,366	-11,094	-12,810	-14,516	-16,156	-16,147	-16,138
NT	-1,130	-2,494	-4,211	-6,151	-8,464	-10,980	-13,575	-16,186	-18,793	-21,434	-21,410	-21,381
ACT	-1,580	-3,245	-5,016	-6,892	-8,802	-10,708	-12,608	-14,503	-16,394	-18,298	-18,289	-18,280
Cumulative change in off-peak electricity consumption (MWh)												
NSW	-617	-1,246	-1,945	-2,718	-3,519	-4,309	-5,083	-5,846	-6,600	-7,346	-7,346	-7,346
VIC	-216	-431	-660	-919	-1,213	-1,521	-1,829	-2,131	-2,429	-2,729	-2,729	-2,729
QLD	-13,946	-28,508	-44,808	-62,862	-81,572	-99,541	-116,714	-133,816	-150,887	-167,993	-167,993	-167,993
SA	-1,439	-2,832	-4,317	-6,130	-8,158	-10,051	-11,827	-13,578	-15,309	-16,989	-16,989	-16,989
WA	-261	-538	-837	-1,155	-1,488	-1,815	-2,137	-2,456	-2,772	-3,089	-3,089	-3,089
TAS	-1,092	-2,162	-3,280	-4,481	-5,748	-7,038	-8,309	-9,562	-10,800	-11,982	-11,982	-11,982
NT	-11	-24	-42	-63	-90	-120	-153	-187	-223	-260	-260	-260
ACT	-620	-1,266	-1,946	-2,658	-3,375	-4,083	-4,781	-5,470	-6,149	-6,826	-6,826	-6,826

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total cumulative change in electricity consumption (MWh)[a]												
NSW	-26,007	-52,136	-80,718	-111,808	-143,561	-174,326	-204,044	-232,810	-260,780	-288,008	-287,726	-287,443
VIC	-13,317	-26,293	-39,898	-54,901	-71,661	-88,856	-105,720	-121,944	-137,659	-153,181	-152,948	-152,722
QLD	-17,638	-36,014	-56,540	-79,227	-102,690	-125,179	-146,629	-167,950	-189,193	-210,441	-210,343	-210,243
SA	-4,657	-9,135	-13,885	-19,648	-26,055	-32,004	-37,551	-42,990	-48,335	-53,492	-53,398	-53,308
WA	-6,230	-12,846	-19,990	-27,583	-35,506	-43,298	-50,957	-58,563	-66,080	-73,614	-72,977	-72,304
TAS	-2,521	-4,998	-7,600	-10,402	-13,371	-16,403	-19,403	-22,372	-25,316	-28,138	-28,129	-28,120
NT	-1,141	-2,518	-4,253	-6,214	-8,553	-11,100	-13,728	-16,373	-19,016	-21,695	-21,671	-21,642
ACT	-2,200	-4,511	-6,962	-9,549	-12,177	-14,792	-17,389	-19,973	-22,544	-25,124	-25,115	-25,106
Cumulative change in summer peak demand (MW)												
NSW	-24	-48	-74	-103	-132	-161	-189	-215	-242	-267	-267	-267
VIC	23	46	70	96	125	154	183	211	237	263	263	263
QLD	3	6	9	12	15	18	20	22	24	26	26	26
SA	-7	-13	-19	-27	-36	-44	-52	-59	-66	-73	-73	-73
WA	-4	-8	-12	-17	-21	-26	-30	-34	-38	-41	-41	-41
TAS	-3	-6	-8	-12	-15	-18	-21	-25	-28	-31	-31	-31
NT	-1	-1	-2	-3	-4	-6	-7	-8	-10	-11	-11	-11
ACT	-2	-4	-7	-9	-11	-14	-16	-19	-21	-24	-24	-24

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cumulative change in winter peak demand (MW)												
NSW	-11	-23	-35	-48	-62	-75	-88	-100	-112	-124	-124	-124
VIC	90	178	269	370	481	595	707	814	917	1,018	1,018	1,018
QLD	-21	-43	-68	-95	-124	-151	-177	-203	-229	-255	-255	-255
SA	-3	-6	-9	-13	-17	-20	-24	-27	-31	-34	-34	-34
WA	5	10	16	22	28	35	41	47	54	60	60	60
TAS	-3	-7	-10	-14	-18	-22	-25	-29	-33	-37	-37	-37
NT	0	0	1	1	1	1	2	2	3	3	3	3
ACT	-3	-7	-11	-15	-18	-22	-26	-30	-34	-38	-38	-38
Cumulative difference in PV capacity (MW)												
NSW	50	100	155	214	274	332	388	442	494	544	544	544
VIC	46	91	137	189	246	304	361	416	468	520	520	520
QLD	1	2	3	4	5	6	7	8	9	10	10	10
SA	5	10	16	22	29	36	42	48	54	59	59	59
WA	7	15	24	33	42	51	60	69	78	87	87	87
TAS	2	3	5	7	9	11	13	15	17	18	18	18
NT	1	3	5	7	9	12	15	17	20	23	23	23
ACT	1	2	3	5	6	7	8	9	11	12	12	12

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cumulative change in energy generated by PV (MWh)												
NSW	65,692	131,465	203,151	280,841	359,883	436,162	509,545	580,281	648,756	715,114	715,114	715,114
VIC	58,865	116,029	175,767	241,410	314,483	389,185	462,180	532,138	599,643	666,055	666,055	666,055
QLD	1,376	2,781	4,319	5,984	7,670	9,254	10,734	12,176	13,583	14,961	14,961	14,961
SA	7,407	14,508	22,016	31,097	41,160	50,473	59,130	67,588	75,875	83,842	83,842	83,842
WA	10,993	22,659	35,243	48,607	62,542	76,233	89,680	103,023	116,198	129,390	129,390	129,390
TAS	1,955	3,869	5,872	8,021	10,289	12,597	14,872	17,114	19,329	21,444	21,444	21,444
NT	1,938	4,264	7,178	10,450	14,331	18,529	22,835	27,139	31,413	35,714	35,714	35,714
ACT	1,515	3,095	4,762	6,511	8,275	10,020	11,743	13,444	15,127	16,805	16,805	16,805
Cumulative difference in energy exported by PV (MWh)												
NSW	42,138	84,325	130,305	180,133	230,826	279,745	326,806	372,167	416,077	458,628	458,628	458,628
VIC	35,695	70,359	106,585	146,391	190,704	236,005	280,272	322,698	363,636	403,912	403,912	403,912
QLD	1,198	2,420	3,757	5,206	6,673	8,051	9,339	10,593	11,817	13,016	13,016	13,016
SA	-1,580	-3,245	-5,016	-6,892	-8,802	-10,708	-12,608	-14,503	-16,394	-18,298	-18,289	-18,280
WA	7,719	15,910	24,747	34,131	43,917	53,531	62,974	72,345	81,598	90,863	90,863	90,863
TAS	1,209	2,393	3,632	4,961	6,364	7,792	9,199	10,585	11,956	13,264	13,264	13,264
NT	1,066	2,347	3,951	5,753	7,892	10,207	12,581	14,957	17,316	19,691	19,691	19,691
ACT	926	1,893	2,911	3,979	5,055	6,120	7,170	8,206	9,231	10,252	10,252	10,252

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cumulative change in gas consumption (TJ)												
NSW	-15	-31	-49	-68	-88	-107	-126	-145	-164	-182	-182	-182
VIC	-274	-541	-820	-1,128	-1,472	-1,824	-2,169	-2,501	-2,823	-3,140	-3,140	-3,140
QLD	-3	-6	-9	-13	-17	-20	-24	-28	-32	-35	-35	-35
SA	-8	-15	-23	-33	-43	-53	-63	-72	-81	-90	-90	-90
WA	-32	-65	-102	-141	-181	-221	-260	-299	-338	-376	-376	-376
TAS	-02	-3	-5	-6	-8	-10	-12	-14	-16	-17	-17	-17
NT	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0
ACT	-5	-10	-16	-22	-28	-34	-40	-45	-51	-57	-57	-57

[a] Totals may not add up due to rounding.

Source: ACIL Allen analysis

K.3 Federal and state energy policies

The Australian Government continues to be committed to the Paris Agreement target of between 26 and 28 per cent reduction in GHG emissions below 2005 levels by 2030. Each year, the Government releases economy-wide emissions projections to measure progress towards its 2030 target. Its 2021 projections show that the incremental abatement required in the period 2021-22 to 2029-30 to meet the 2030 commitment is now between -148 and -80 Mt CO2-e (the range reflecting the bounds of 26 to 28 per cent reduction). This means there is an overachievement of 4.3 to 2.3 per cent of emission reduction over the period 2021-2030. The reason Australia is projected to reach the Paris Agreement target of 26-28 per cent early is the announcement of the early closure of Yallourn and the Altona Refinery, as well as the impact of additional decarbonisation policies on federal and state level.

All governments have a net zero emissions target by 2050. To achieve their objective, each jurisdiction is implementing its own policies with most focusing their efforts in the electricity sector, which is well understood to provide the most cost-efficient and least challenging abatement opportunities in the short-term, given the available renewable energy technologies. (Comparatively, abatement in other sectors such as agriculture and transport is more challenging and will take time to implement.) The electricity sector also currently accounts for about one third of Australia's emissions.

The Large-scale Renewable Energy Target (LRET) was met in September 2019. In 2020, a number of states legislated new renewable energy policies (see Figure K.9). Tasmania legislated ambitious renewable targets of 150 per cent by 2030 and 200 per cent by 2040 (TRET). New South Wales legislated their Electricity Infrastructure Roadmap (the Roadmap). These are in addition to the QRET[21] and VRET which were already in place.

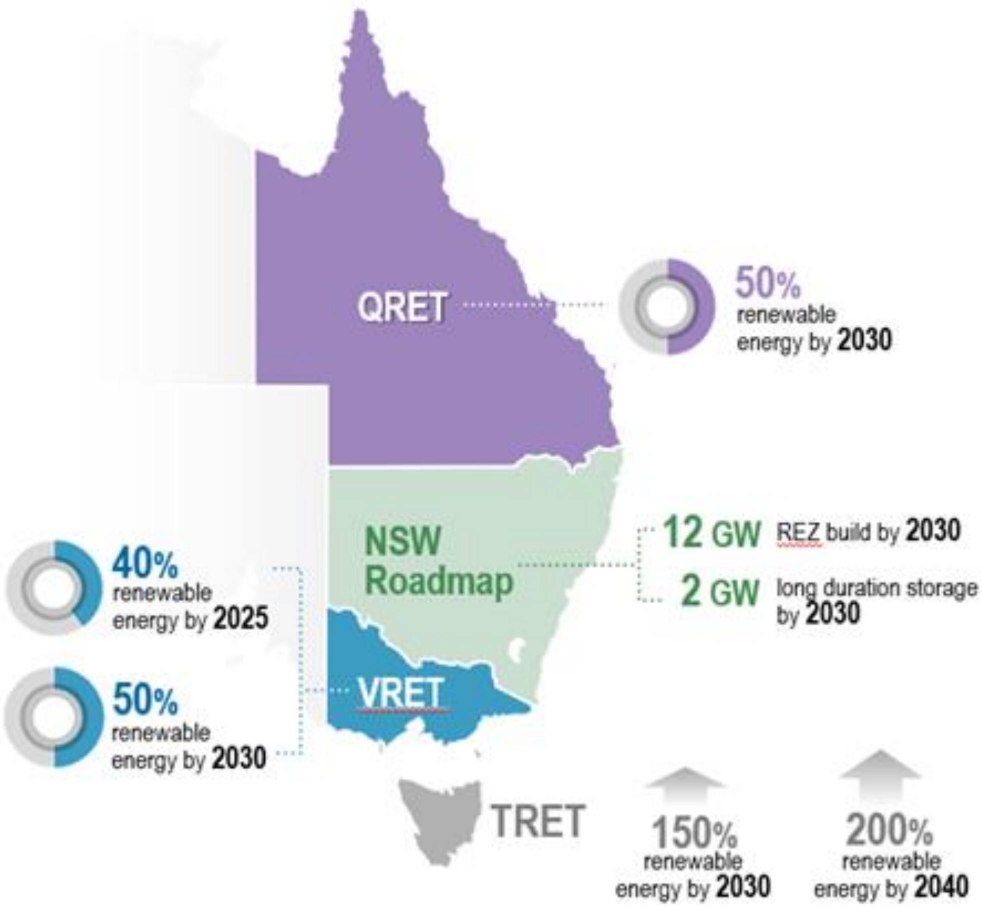
There has also been a particular focus from the state governments of New South Wales, Queensland and Victoria to support the development of Renewable Energy Zones (REZ) as laid out by AEMO's Integrated System Plan (ISP). The development of these zones will assist them to achieve their renewable energy targets.

The following sections cover the current renewable energy policies which affect the NEM along with a discussion of ACIL Allen's modelling assumptions to implement these policies in our market projection.

The reference case energy policy assumptions for the period post-2030 are detailed in Appendix K.3.2.

[21] The QRET is at this time not a legislated target.

Figure K.9 State renewable energy policies included in reference case



Note: South Australia has indicated an ambition of 100% net renewable energy generation by 2030 in their Climate Change Action Plan (2021-2025).
Source: ACIL Allen

K.3.1 Current energy policies

The LRET

The Commonwealth Government's LRET has a direct impact on the electricity sector through the incentives it provides for the development of centralised renewable generation. However, in more recent years, a combination of favourable electricity market conditions and the rapidly declining cost of renewables has encouraged a significant amount of investment in new large-scale wind and solar capacity in the NEM.

The reference case assumes an annual LRET target of 33,000 MWh from 2020 to 2030, which is the current policy. The target has been met and the scheme is now oversubscribed.

In the reference case, the projected price of Large-scale Generation Certificates (LGCs)[22] reduces the short-run marginal cost (SRMC) of all semi-scheduled wind and solar farms.

The NSW Roadmap

The New South Wales Electricity Infrastructure Roadmap (the Roadmap) requires 12,000 MW of renewables to be developed by 2030:

— 8,000 MW in the New England REZ

— 3,000 MW in the Central-West Orana REZ (referred herein as *Central West*), and

— another 1,000 MW in the remaining REZs (South West, Central Tablelands and/or Central Coast).

The Roadmap also requires an additional 2,000 MW of long-duration storage (not including Snowy 2.0) to be built by 2030. The Roadmap is set out in the *Electricity Infrastructure Investment Act 2020*.

The reference case assumes the Roadmap capacity is added to the market in approximately a straight-line over the period from 2023 through 2027 and is then assumed to ramp up further to 2030 as the New England REZ is fully developed (see Figure K.10).

ACIL Allen has identified a total of 1,923 MW of committed and operational projects which are potentially eligible to form part of the Roadmap. These projects are for the most part located in either the New England or Central West zones and were identified as committed or existing in a generation information page published by AEMO under the National Electricity Rules after 14 November 2019 (per the eligibility requirement outlined in the Act). They are assumed to enter the market between 2021 and 2024 and include:

— Crudine Ridge wind farm (135 MW, Central West)

— Nevertire solar farm (105 MW, Central West)

— Goonumbla solar farm (69 MW, Central West)

— Molong solar farm (36 MW, Central West)

— Gunnedah Solar Farm (110 MW, Central West)

— Metz solar farm (115 MW, New England)

— West Wyalong Solar Farm (90 MW, South West)

— Suntop Solar Farm (150 MW, Central West)

— Wellington solar farm (174 MW, Central West)

— Crookwell 3 wind farm (58 MW, Southern)

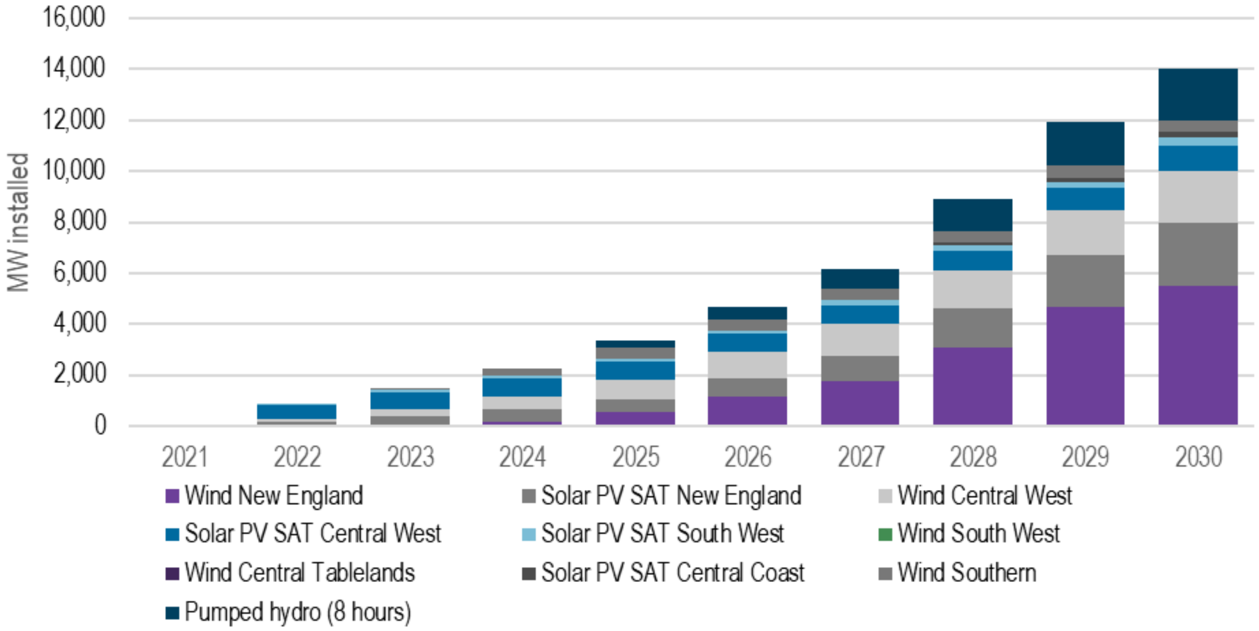
— New England solar farm (400 MW, New England)

— Rye Park wind farm (396 MW, Southern)

— Hillston Sun Farm (85 MW, South West).

[22] 1 LGC represents 1 MWh of eligible renewable generation

Figure K.10 Assumed New South Wales Roadmap capacity, by technology type and REZ (MW), 2021 to 2030



Source: ACIL Allen

The ACT's 100% renewable energy target

In 2016, the ACT Government legislated a target of sourcing 100 per cent of its electricity consumption from renewable sources, either in the ACT or across the NEM, by 2020. Reverse auctions were held to meet this target.

The legislation was subsequently amended to require this target to be maintained. The ACT Government will procure new renewable energy sources as required to manage future increases in electricity consumption.

The Queensland RET

There are several initiatives by the Queensland Government under the Powering Queensland Plan including:

— affirming a target of 50 per cent renewable energy in Queensland by 2030 (QRET)

— establishment of CleanCo based around Wivenhoe and Swanbank E (and hydro plant in north Queensland) with the objective of 'firming up' contracted renewable energy and supporting up to 1,000 MW of majority Government owned renewable energy projects. In May 2020, CleanCo committed to:

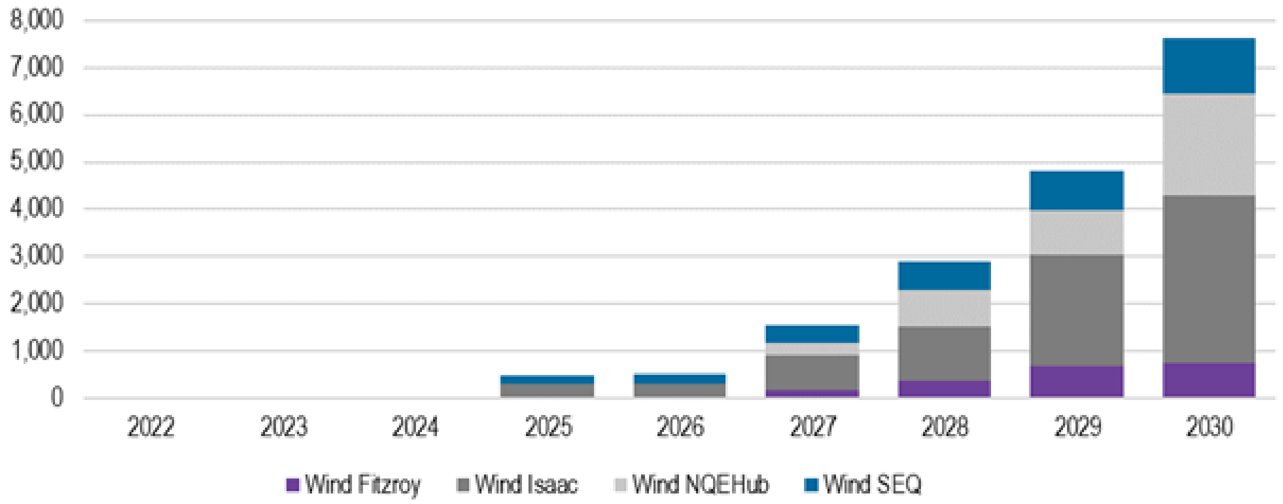
  – a 400 MW power purchase agreement with the owners of MacIntyre wind farm resulting from the Government's Renewables 400 initiative. CleanCo also announced that it will build its own 100 MW wind farm on the same site.

  – a 320 MW power purchase agreement with the owners of Western Downs solar farm.

ACIL Allen assumes that the CleanCo portfolio will include a further 100 MW of battery storage to compliment these renewable off-take agreements (in line with the original intent of the Renewables 400 reverse auction).

Our analysis shows that a further 7,900 MW of new wind capacity[23] will be required by 2030 to meet the QRET. This capacity is assumed to be added to the market from 2026 such that the state's renewable energy penetration increases approximately linearly to 2030 (see Figure K.11).

Figure K.11 Assumed QRET capacity, by technology type and REZ (MW), 2022 to 2030



Source: ACIL Allen

The Victorian RET

The Victorian Government has committed to renewable energy generation targets (VRET) of 40 per cent by 2025 and 50 per cent by 2030, which are being met through the Victorian Renewable Energy Auction Scheme (VREAS). The scheme involves establishing power purchase agreements with entrant renewable projects which are allocated through reverse auctions.[24]

For the first round VRET auction, six projects totalling 928 MW of grid-based wind and solar PV projects were announced in September 2018.

In September 2020, the Victorian Government announced it would procure an additional 600 MW of new solar and wind energy capacity through a second VRET auction (VRET2) to make the energy requirements of government operations 100 per cent renewable.

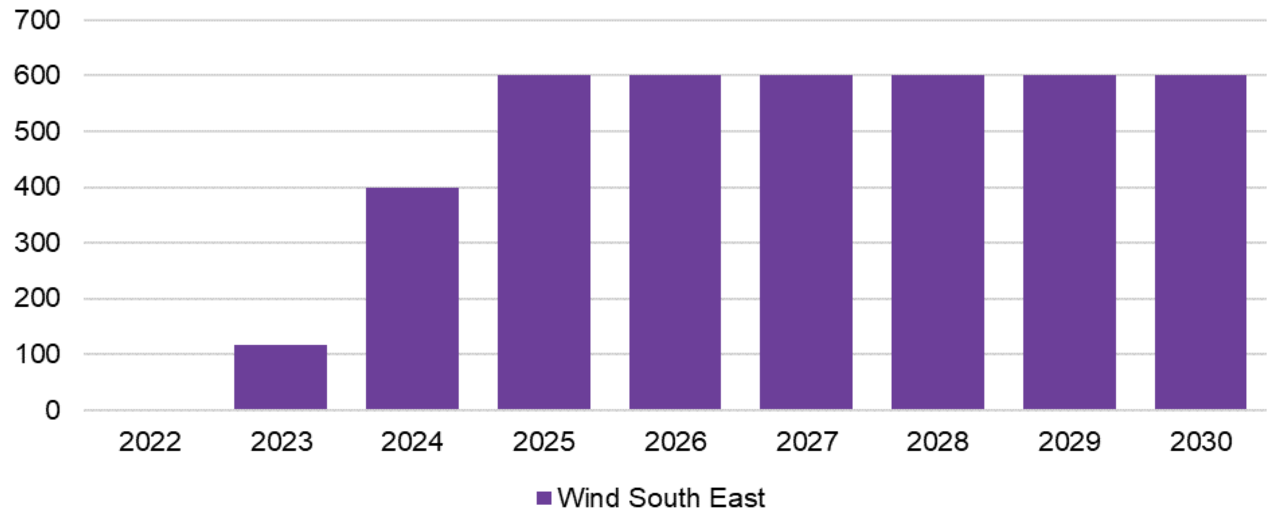
[23] ACIL Allen's modelling shows that given the high uptake of utility-scale solar as well as rooftop PV in Queensland which are cannibalising the wholesale revenues for solar, investment in new utility solar is much less attractive than for wind.

[24] Section 7C in the Federal RET legislation effectively invalidates any state-based scheme which is substantially similar to the Federal scheme. This effectively prohibits the states from employing a certificate-based market scheme to encourage additional renewables. This is a key reason why state governments have preferred power purchase agreements allocated through reverse auctions.

The Victorian Solar Homes Program will also contribute to these targets, increasing the installations of rooftop solar PV in Victoria.

In the reference case, it is assumed the additional 600 MW of new renewable capacity is committed and enters the market by 2025[25] (see Figure K.12). Under the reference case assumptions, this results in the 50 per cent target being met by 2025.

Figure K.2 Assumed VRET2 capacity – by technology type and REZ (MW), 2022 to 2030



Source: ACIL Allen

The Tasmanian RET

The Tasmanian Government announced the TRET in mid-2020, and passed the required legislation in late 2020. The TRET requires renewable generation equivalent to 150 per cent and 200 per cent of the region's energy requirements by 2030 and 2040, respectively. This equates to an additional 5,250 GWh and 10,500 GWh of annual generation by 2030 and 2040, respectively.

The reference case assumes that the new renewable generation capacity is added to the market in approximately a straight-line over the period from 2027 through 2040 and that most of the TRET will be met by new large-scale wind generation, with a smaller contribution from new rooftop solar PV.

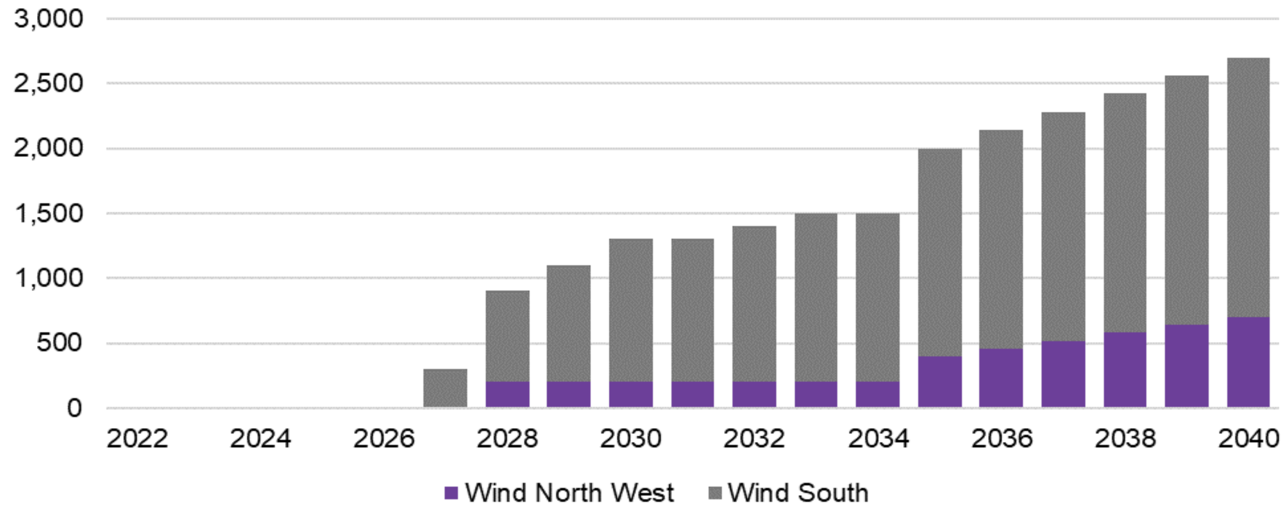
The reference case assumes that the targets of 5,250 GWh by 2030 and 10,500 GWh by 2040 are met using *expected* generation outcomes (based on renewable resource) from new renewable capacity in Tasmania.

Our modelling shows that on top of the TRET capacity increased demand in Tasmania as a result of electrification creates opportunity for additional commercial wind to be built. Increased interconnection between Tasmania and Victoria after 2032, as a result of the commissioning of the two Marinus links

[25] Since the outcomes of VRET2 are not yet known (including technology type and location), ACIL Allen has used the projected market performance of the different technology types in different locations against their build costs to determine the build on a commercial basis. This has resulted in a build of only wind capacity, located in the southeast of the State.

between 2028 and 2032; creates more opportunities for export, hence the build of more commercial wind. By 2040 another 900 MW of wind enters the Tasmanian energy market on top of the TRET capacity shown in Figure K.13.

Figure K.13 Assumed TRET capacity – by technology type and REZ (MW), 2022 to 2040



Source: ACIL Allen

South Australia’s 100% net renewable energy ambition

South Australia has indicated an ambition of 100 per cent net renewable energy generation by 2030 in their Climate Change Action Plan (2021-2025). In 2021, South Australia met 100 per cent of its operational demand from renewable resources on 180 days (49 per cent).[26] Accordingly, there has been no indication to date of potential reverse-style renewable auctions or off-take agreements such as in the other states.

As such, ACIL Allen has not explicitly included the South Australian target in the reference case.

Western Australia’s Energy Transformation Strategy

In recent years, the SWIS has started a transformation driven by changes to the mix of grid-connected large-scale generation technologies, changes in consumer demand patterns, and growth in the penetration of distributed energy resources (DER), such as solar photovoltaics (PV) and battery storage systems, connecting “behind the meter” on commercial and residential sites.

26 https://www.energymining.sa.gov.au/growth_and_low_carbon/leading_the_green_economy#:~:text=South%20Australia%20is%20at%20the,in%20just%20over%2015%20years., accessed 11 April 2022

In particular:

— increasing penetration of behind-the-meter rooftop PV generation – collectively the largest generation system in the SWIS – is leading to significant changes in demand patterns
— increasing penetration of large-scale intermittent generation in areas of the SWIS where transmission capacity is constrained
— the impact of the increasing penetration of large-scale intermittent generation and DER-driven low daytime demand has also led to a significantly higher prevalence of negative pricing.

To address these challenges, a number of changes are being made to the Western Australian Electricity Market, which are scheduled to commence in October 2023, featuring changes to network access, essential system services and the Reserve Capacity Market, and the introduction of a real-time market.

K.3.2 Energy policies beyond 2030

The LRET will end in 2030, and most of the states' renewable energy policies only extend to 2030. It is unclear at this stage what specific action the states may take to reach their respective net zero emissions targets by 2050 and how this will be targeted to different sectors of the economy.

Therefore, ACIL Allen does not assume any further renewable energy state targets post-2030 (except for Tasmania which has legislated its 2040 target). We do however assume that none of the incumbent coal fleet will have the social license to continue their operations through to 2050. That is, we assume they will retire by 2050.

K.4 Generation capacity

ACIL Allen's approach to modelling the NEM's electricity supply is to:

1. incorporate changes to **existing supply** where companies have formally announced the changes – mothballing, closure and change in operating approach
2. include plants that are considered to be **committed projects** (generally once a final investment decision has been reached) as named projects in the model database
3. include additional **capacity requirements to satisfy government policies** (including renewable energy targets assumed in the reference case) as generic entrants
4. include additional **capacity determined to be commercially viable** by the modelling as generic entrants.

K.4.1 Plant closures

NEM

With the exception of those plant that are assessed as being committed to close, ACIL Allen assesses the net revenue on a per kW/year basis for each generator (capital return per installed kW after accounting for variable operating and maintenance (O&M) costs and fixed O&M costs).

Where net revenues become negative on a sustained basis, the generator is closed. While this is, in effect, an exercise in perfect foresight which would not be available to plant owners, we consider that, on balance, it is a reasonable approach to modelling likely outcomes.

The O&M cost profiles for major coal-fired power station is not smooth as it is correlated with major maintenance cycles. However, the modelling assumes a smoothed fixed O&M profile for each station in the NEM as ACIL Allen does not have detailed maintenance schedule information. Therefore, the closure of a given generator, as suggested by the modelling, may in practice be brought forward or delayed slightly by the actual timing of major maintenance outages.

The reference case assumes coal-fired generator operation does not extend beyond the end of their technical life (see Table K.3). Life extension of coal-fired generators is considered unlikely given the continued trend in investment in renewable generation and less emissions intensive firming generation. Coal generators are unlikely to have the social license to continue operating in the long-term given the states' net zero emissions targets by 2050.

Owners of coal fired generators have submitted to AEMO an expected closure year as required by the National Electricity Rules (NER). In most cases the expected closure year is within one year of the end of technical life. Owners are required to provide this information, and update it immediately if it is to change, as it affects AEMO's and the network service providers' system planning activities. The reference case assumes coal generators will not operate beyond their expected closure year.

Table K.3 Assumed end of technical life date and expected closure year

Generator	End of technical life date	AEMO expected closure year
Liddell	2022	2023
Vales Point B	2029	2029
Callide B	2028	2028
Gladstone	2029	2035
Yallourn	2032	2028
Eraring	2033	2033
Bayswater	2035	2035
Tarong	2036	2037
Mt Piper	2043	2040

Generator	End of technical life date	AEMO expected closure year
Stanwell	2045	2046
Loy Yang A	2048	2048
Callide C	2051	Unknown
Millmerran	2052	2051
Tarong North	2052	2037
Loy Yang B	2056	2047
Kogan Creek	2057	2042

Source: ACIL Allen, AEMO

Western Australia

The reference case assumes the following plant closures in Western Australia:

— BP cogeneration unit by calendar year end 2024 – the long-term prospects for this unit are tied to the viability of the Kwinana refinery which ceased operating in 2021

— Muja C in 2024

— Pinjar AB in mid-2025

— Muja D in 2028

— Tiwest cogeneration unit in 2028

— Pinjar C & D in 2031-32

— Pinjarra cogen in 2035-36

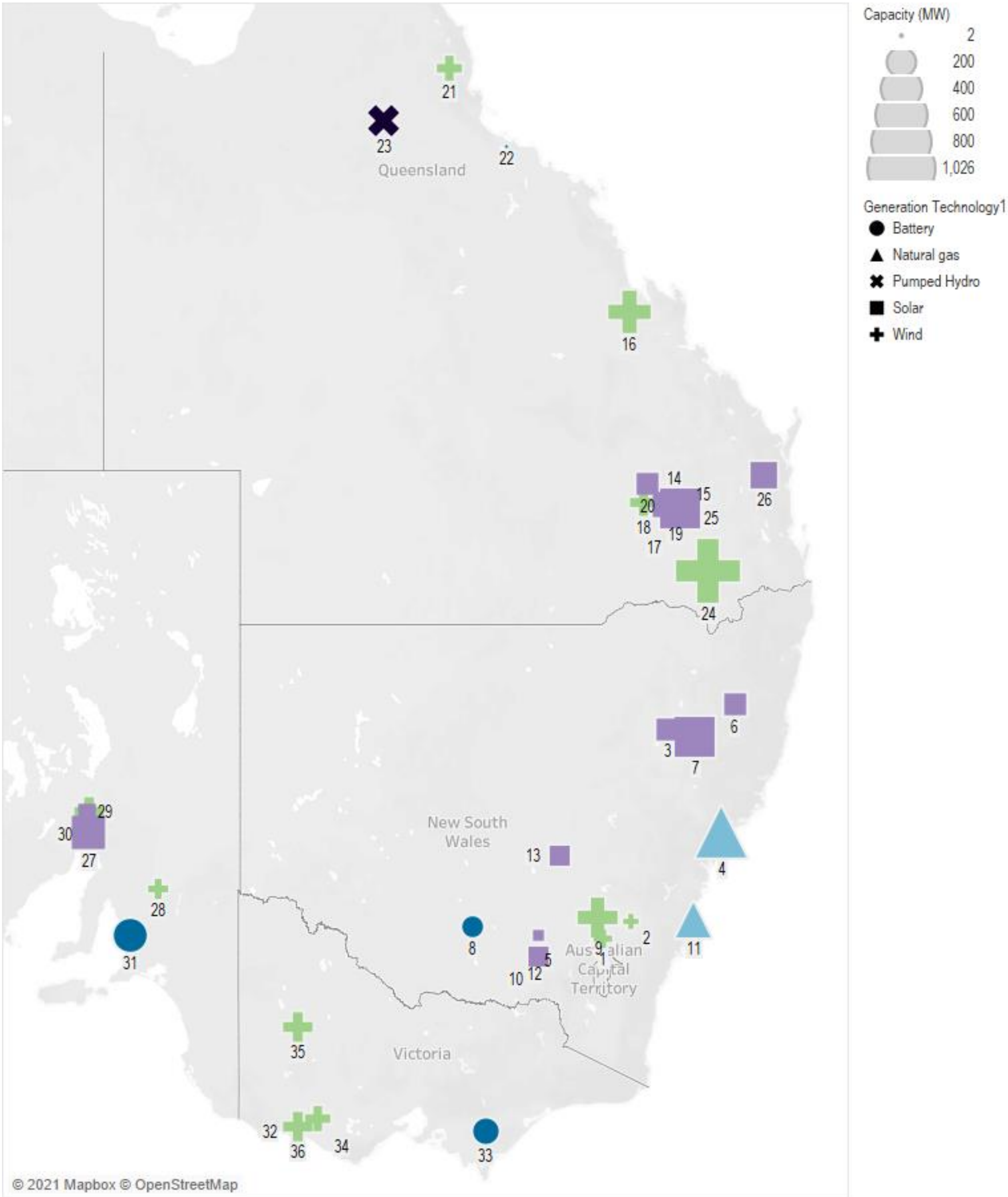
— Cockburn in 2039.

K.4.2 New committed supply

NEM

Figure K.14 and Table K.4 show the near-term entrants that ACIL Allen considers are committed projects and are therefore included in the reference case for the NEM. These projects have not yet commenced exporting energy to the grid but are expected to come online in the near-term future.

Figure K.14 Near-term addition to supply



Note: See Table K.4 for generator project details per ID number on map.
Source: ACIL Allen

Table K.4 Near-term addition to supply

ID	Region	Name	Generation Technology	Capacity (MW)	First energy exports
1	NSW1	Bango Wind Farm (extension)	Wind	85	Q3 2023
2	NSW1	Crookwell 3 WF	Wind	58	Q1 2023
3	NSW1	Gunnedah Solar Farm	Solar	115	Q1 2022
4	NSW1	Hunter Power Project	Natural gas	660	Q4 2023
5	NSW1	Junee Solar Farm	Solar	30	Q4 2022

ID	Region	Name	Generation Technology	Capacity (MW)	First energy exports
6	NSW1	Metz Solar Farm	Solar	115	Q1 2022
7	NSW1	New England Solar Farm	Solar	400	Q3 2022
8	NSW1	Riverina Energy Storage System Discharge	Battery	100	Q1 2023
9	NSW1	Rye Park WF	Wind	396	Q1 2024
10	NSW1	Sebastopol Solar Farm	Solar	90	Q2 2022
11	NSW1	Tallawara B Power Station	Natural gas	316	Q4 2023
12	NSW1	Wagga North Solar Farm	Solar	30	Q1 2022
13	NSW1	West Wyalong Solar Farm	Solar	90	Q1 2023
14	QLD1	Bluegrass Solar Farm	Solar	148	Q3 2022
15	QLD1	Chinchilla Solar Farm	Solar	100	Q1 2022
16	QLD1	Clarke Creek WF	Wind	450	Q3 2023
17	QLD1	Columboola Solar Farm	Solar	162	Q3 2022
18	QLD1	Dulacca WF	Wind	180	Q1 2023
19	QLD1	Edenvale Solar Park	Solar	146	Q1 2023
20	QLD1	Gangarri Solar Farm	Solar	120	Q1 2022
21	QLD1	Kaban WF	Wind	157	Q1 2023
22	QLD1	Kennedy Battery	Battery	2	Q1 2022
23	QLD1	Kidston Storage Hydro	Pumped Hydro	250	Q3 2024
24	QLD1	Macintyre Wind Farm	Wind	1026	Q1 2023
25	QLD1	Western Downs Solar Farm	Solar	400	Q1 2022
26	QLD1	Woolooga Solar Farm	Solar	176	Q4 2022
27	SA1	Cultana Solar Farm	Solar	280	Q2 2023
28	SA1	Goyder South WF	Wind	100	Q3 2024
29	SA1	Port Augusta Solar Farm	Solar	79	Q1 2022
30	SA1	Port Augusta WF	Wind	210	Q1 2022
31	SA1	Torrens Island BESS	Battery	250	Q1 2023
32	VIC1	Hawkesdale WF	Wind	109	Q3 2022

ID	Region	Name	Generation Technology	Capacity (MW)	First energy exports
33	VIC1	Hazelwood Battery	Battery	150	Q4 2022
34	VIC1	Mortlake South WF	Wind	157.5	Q1 2022
35	VIC1	Murra Warra 2 WF	Wind	209	Q3 2022
36	VIC1	Ryan Corner WF	Wind	218	Q3 2022

Source: ACIL Allen

Western Australia

The only committed new supply in Western Australia is the 100 MW Cunderdin solar farm, scheduled for completion in 2023.

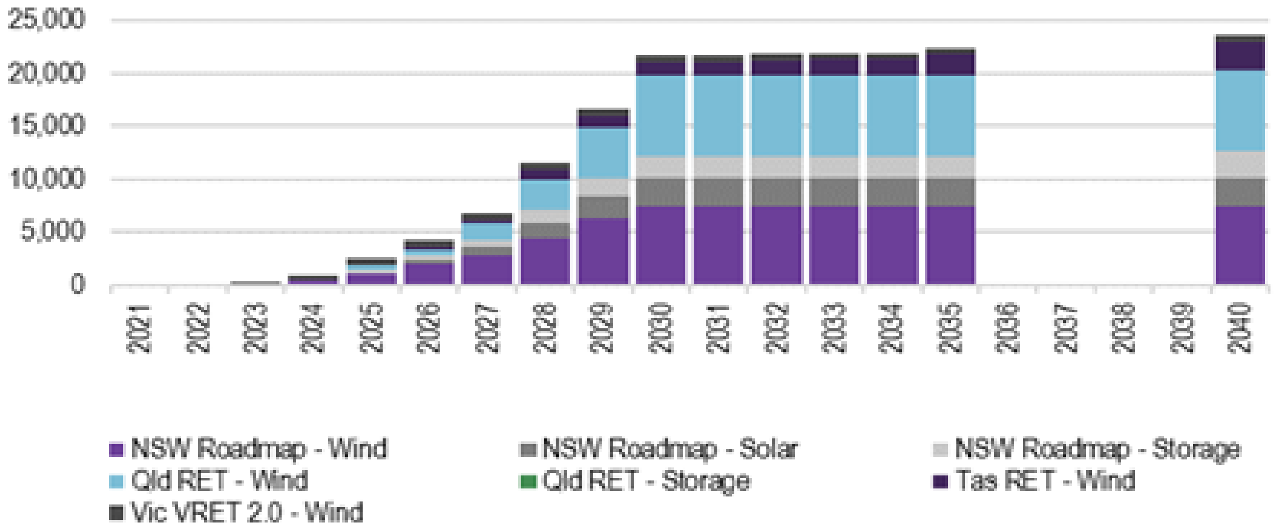
K.4.3 New supply to meet state renewable energy targets

Our analysis shows that the assumed state based renewable energy policies in the reference case will require about 21,700 MW of new investment between 2022 and 2030 as shown in Figure K.15. Although a huge task, about 12,000 MW of renewable capacity has been commissioned in the NEM within the past decade.

Unless specified as part of the relevant policy, the reference case introduces new investment to satisfy each policy on a least cost basis in terms of technology, location and timing.

The projected new investment by state is described in further detail in Section K.3.1.

Figure K.15 Projected new investment resulting from assumed state based renewable energy policies (MW), 2021 to 2050



Note: 1. No state targets assumed beyond 2040. 2. The wholesale energy market is modelled annually to 2035, then in each fifth year from 2035 to 2050, with the results extrapolated in the intervening years..
Source: ACIL Allen

K.4.4 New commercial investment

Beyond the new investment considered as committed to enter the market over the next 12 to 24 months, and the investment required to satisfy government policies, *PowerMark* introduces utility scale new investment in generation capacity based on price signals, rather than using some form of centralised planning criteria.

This approach attempts to mimic the investment decisions made by project proponents. The modelling assumes perfect foresight and introduces the most profitable new entrant, in terms of scale, technology and location, provided that once it is introduced, it meets its required investment return over the long term.

A note on reserve levels

It should be noted that this approach to modelling new entry may result in reserve levels which are below what AEMO might consider to be required to ensure reliability criteria are met. Where this is the case, it is implicitly assumed in the reference case that AEMO utilises its Reserve Trader Role to contract for additional supply and that this supply is offered to the market at the market price cap and therefore only operates when unserved energy is likely to occur. This additional supply therefore does not affect projected market price outcomes.

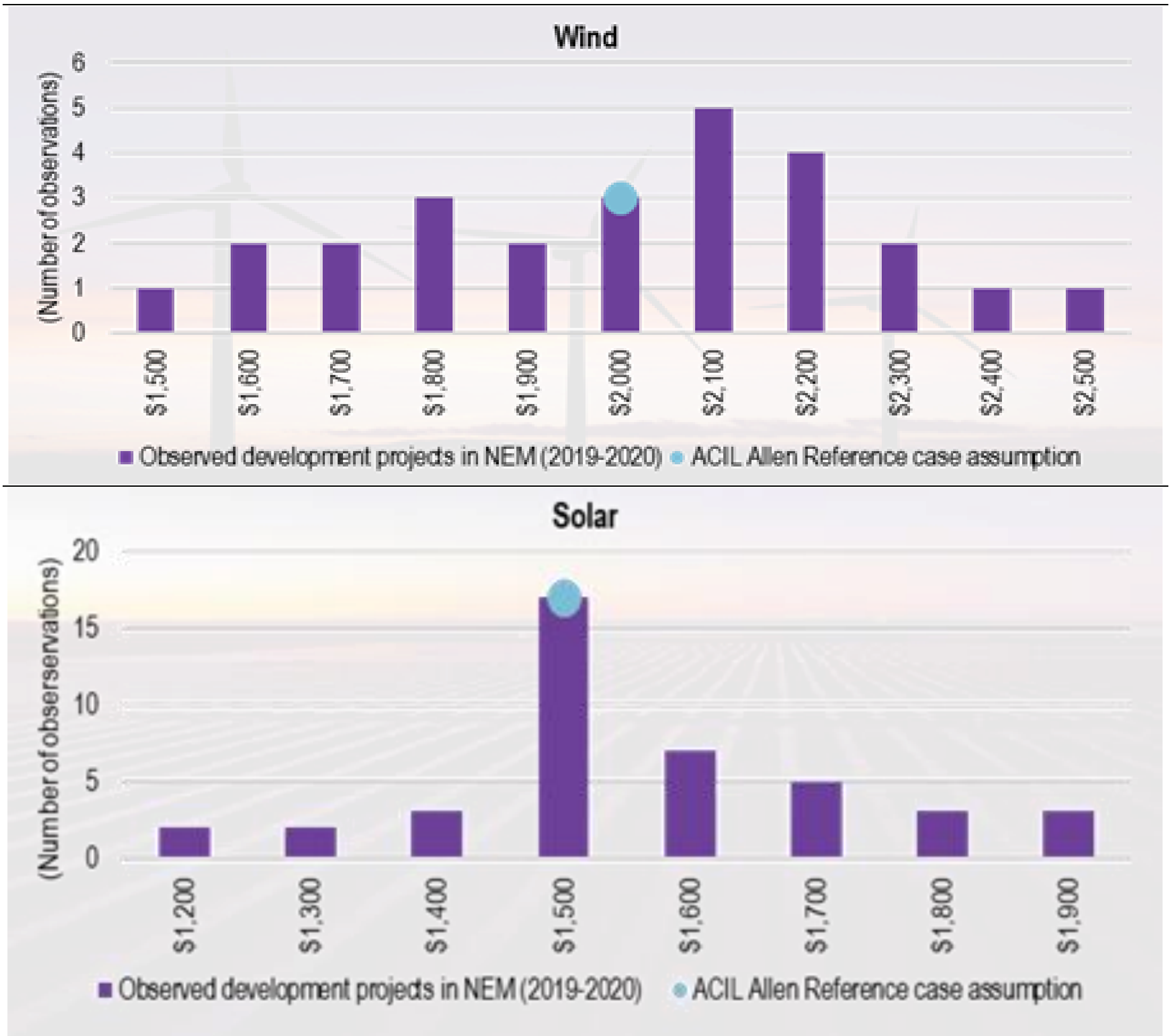
Assumed capital costs of new candidate technologies

PowerMark includes a number of different technologies as candidates for commercial new investment in the reference case.

The starting points for our capital cost estimates for wind, solar, combined cycle gas turbine (CCGT) and aeroderivative gas turbine (GT) technologies are derived from our internal database of observed new entrant projects. Starting capital costs for storage technologies are based on a combination of published sources supplemented with de-sensitised information we have gathered when working for clients on development projects of similar type.

Figure K.16 shows that the starting capital costs assumptions we adopt for the two most dominant new entrant technologies, wind and solar, in the reference case sit close to the mid-point of the distribution of recent development project costs.

Figure K.16 Distribution of observed wind and solar farm capital costs in the NEM ($AUD/kW, real 2021)

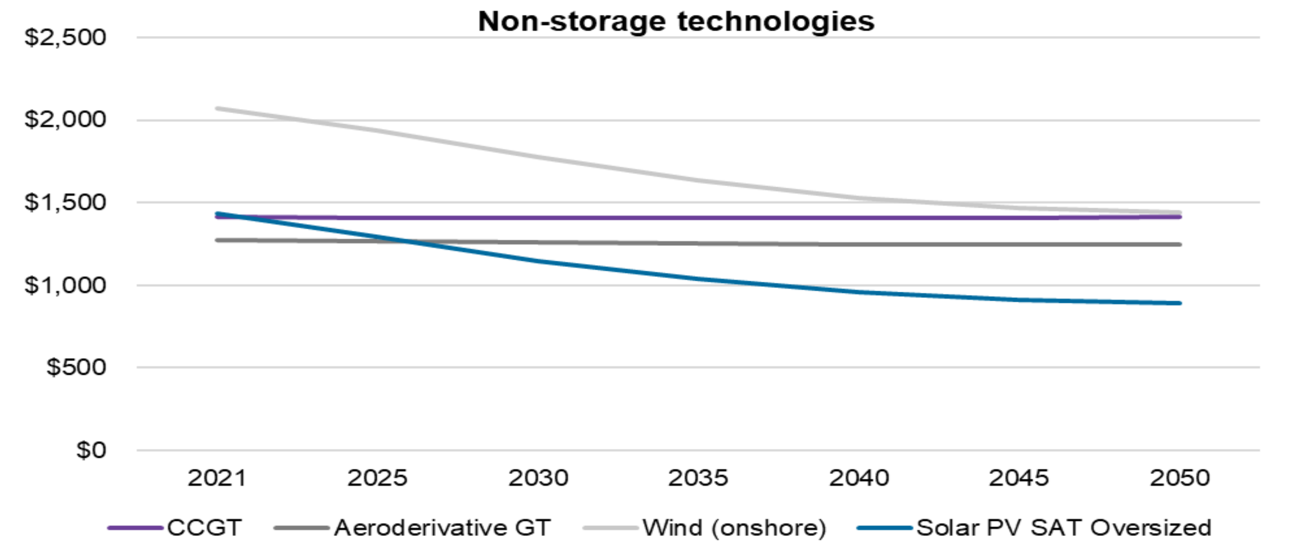


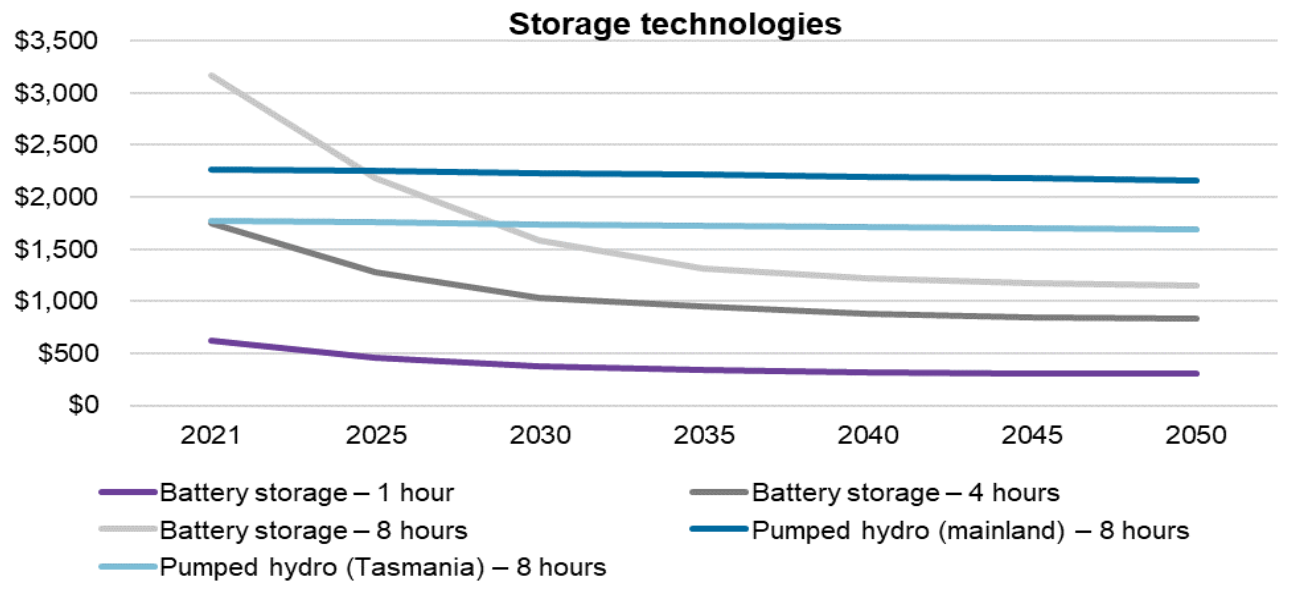
Source: ACIL Allen analysis of public announcements

Figure K.17 summarises the trend in assumed capital costs for non-storage and storage technologies in the reference case. Mature technologies, such as gas fired generators and pumped hydro, are assumed to experience little if any further decline in capital costs. Wind and solar capital costs are assumed to experience a decline of about 20 and 30 per cent respectively between now and 2035, and battery storage costs are assumed to decline by about 50 per cent by 2035.

ACIL Allen maintains a database of cost and technical data for other technologies in addition to those shown above. However, we limit the list of candidate technologies adopted in the modelling to those which are viable under a range of different scenarios.

Figure K.17 Assumed capital costs by new candidate technology and year of commissioning ($AUD/kW, real 2021)





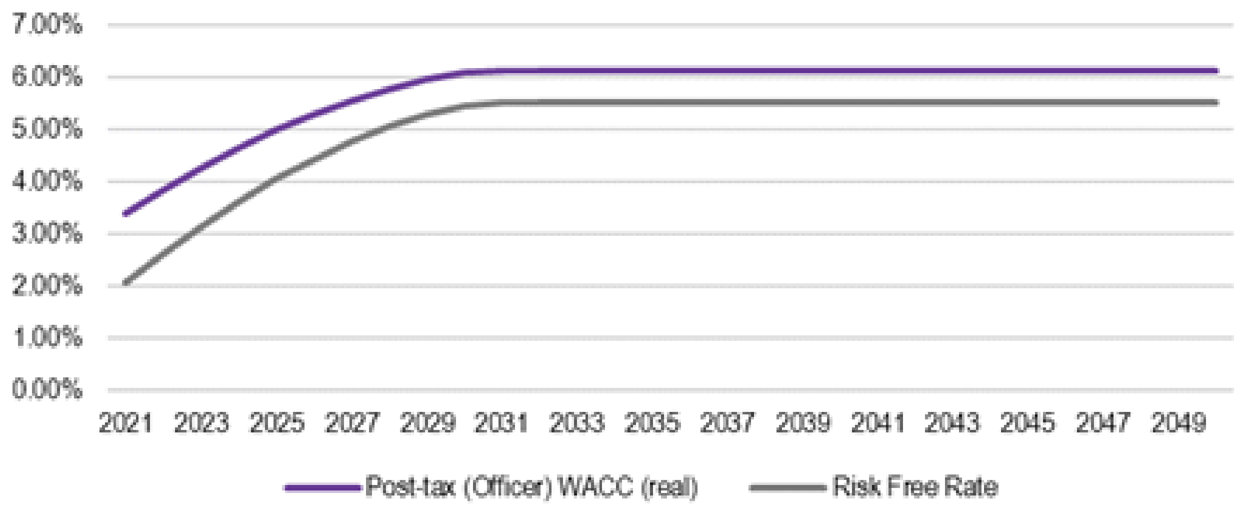
Source: ACIL Allen

Weighted Average Cost of Capital

The required returns for new entrant power generation projects are derived using a discounted cash flow model with a discount factor set at the investment's assumed WACC. We use a standard post tax real officer WACC formulation.

Our estimate of the current post tax real WACC for power generation projects is 3.40 per cent based on the lower current interest rates. The reference case assumes interest rates normalise by the mid-2030s and similarly the WACC recovers to a long-term assumption of 6.13 per cent (see Figure K.18).

Figure K.18 Assumed WACC and risk-free rate (%)



Source: ACIL Allen

Resulting Levelised Cost of Electricity (LCOEs)

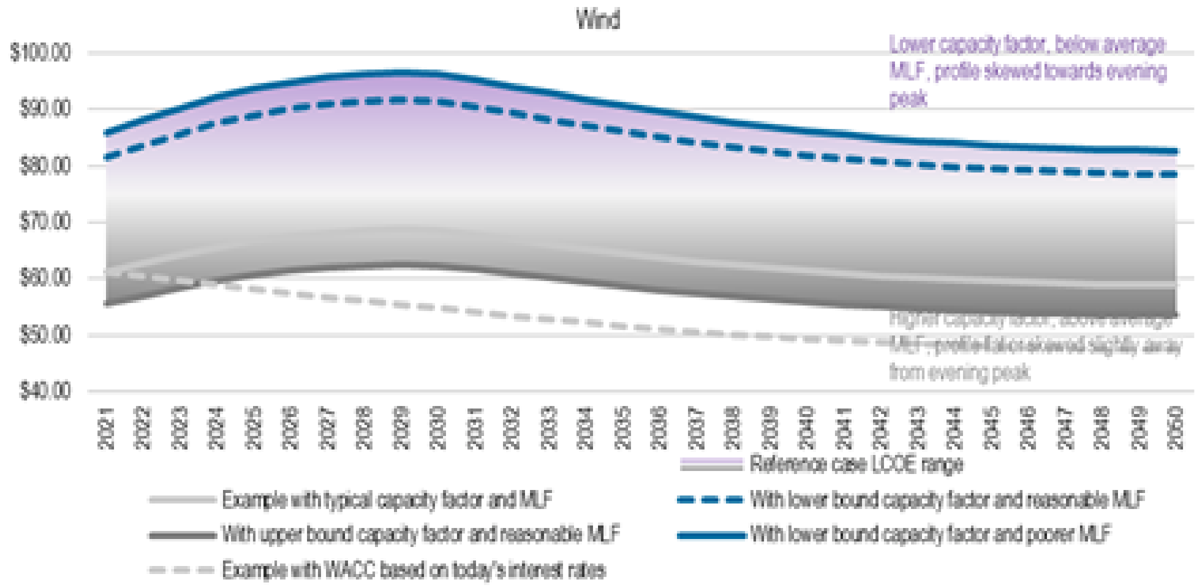
ACIL Allen takes the assumed new entrant costs inputs and calculates the **annualised capital costs** of new entrant generation projects in the NEM using a discounted cash flow (DCF). The values are expressed in $ per kW of installed capacity per year. These values are then **added to O&M costs**, to arrive at the **levelised cost of electricity (LCOE)**, which takes into account the volume of generation, or capacity factor, of the given new entrant project.

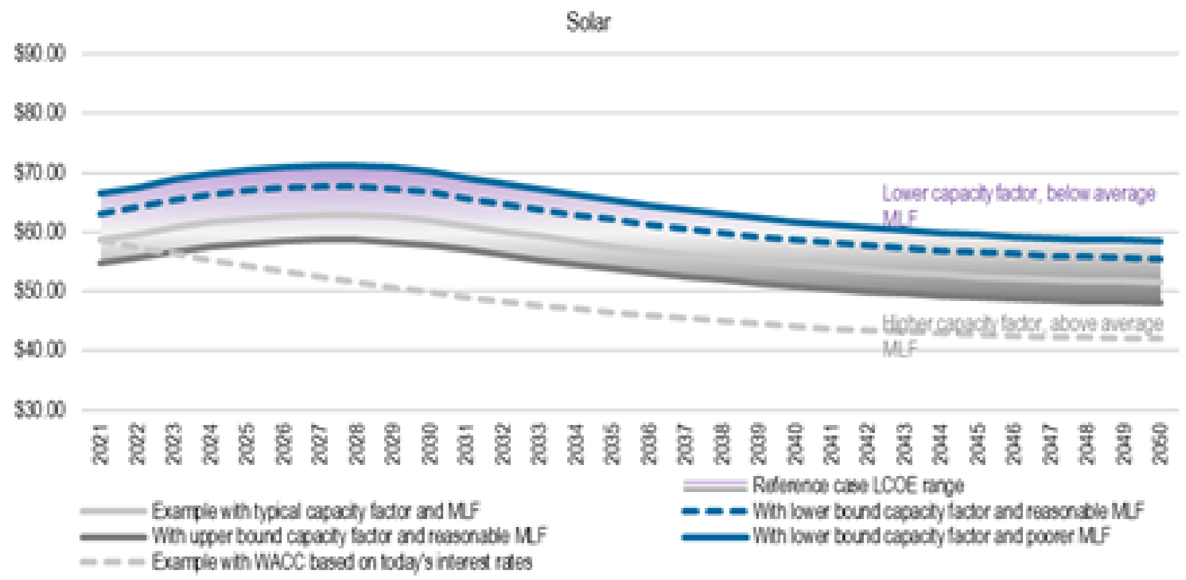
PowerMark's modelling framework uses the **annualised capital costs**, rather than the LCOE, which fluctuates due to variations in capacity factor, when assessing new investment viability.

Figure K.19 shows the assumed LCOEs for wind and solar throughout the projection period. The LCOEs presented in these graphs are measured at the regional reference node, and therefore are inflated to account for auxiliaries (internal usage of electricity) and adjusted (either inflated or deflated) for marginal loss factors (MLFs). The graphs show a range of LCOEs for each technology – this is a function of the range in capacity factors observed in the modelling.

Capacity factors for wind and solar vary across the NEM due to differences in the renewable energy resource (for example, Tasmania has a wind resource that in general results in higher capacity factors than other locations in the NEM), and the extent of curtailment (that is, the extent that the available resource is not dispatched into the NEM for commercial or network limitation reasons[27]).

Figure K.19 Projected range of LCOE for wind and solar by year of commissioning ($/MWh), 2021 to 2050





Source: ACIL Allen

Figure K.19 shows that wind farm technology has a much larger range of LCOEs when compared with solar (about 2.5 times the range). This is not surprising, as the wind resource across the NEM is more varied than the solar resource.

[27] The PowerMark modelling takes into account commercial curtailment only (except for any assumed curtailment in the short-term due to known network limitations).

This does not necessarily mean that a wind farm project with a low capacity factor will be less attractive than a wind farm with a higher capacity factor. The relative viability of a project will be a function of its:

— **Time of day and seasonal resource profile –** with resources skewed towards the evening peak more viable since they are more likely to benefit from high priced outcomes during the day.
— **Marginal loss factor** – with resources located in favourable parts of the grid, close to load centres, being able to earn a higher revenue per unit of output compared with projects located further from load centres.
— **Capacity factor** – an increase in volume of output per unit of capacity installed increases the revenue earnt for the same capital cost.

LCOEs are assumed to increase slightly between 2022 and 2035, before decreasing slightly between 2030 and 2050. This is primarily a result of an **assumed recovery in interest rates** (and hence, in the weighted average cost of capital) from recent very low levels to more normalised levels over the next decade or so. In other words, the real decline in capital costs is more than offset by an increase in interest rates during this period.

As a point of illustration, Figure K.19 includes the assumed LCOE for an example of a typical project **if interest rates were to remain constant** in real terms throughout the projection period. If interest rates were to remain at today's levels, the LCOE of a typical wind farm project would decrease from about $61/MWh today to about $48/MWh in 2050; and the LCOE of a typical solar farm would decrease from about $59/MWh today to just under $42/MWh by 2050. (The LCOE will not decrease at the same rate as the decline in capital costs since O&M costs are assumed not to decline.)

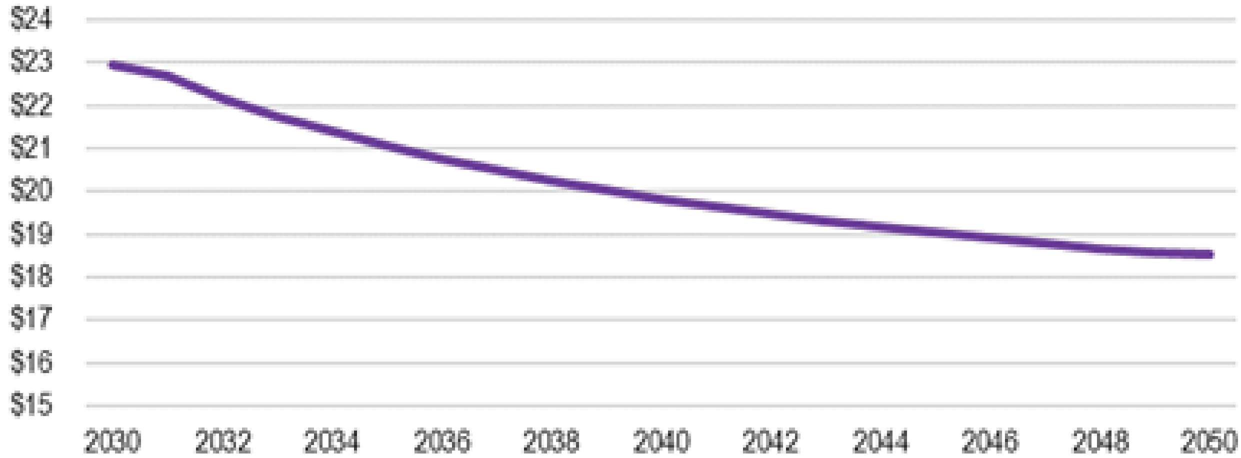
K.5 Fuel costs

Fuel costs are an important input in a natural gas or coal generator's short-run marginal cost. Other technology types such as wind and solar have zero fuel cost, while pumped hydro and batteries face the cost of recharging at the pool price. The marginal cost of acquiring water for hydro plant is usually zero or close to zero per MWh generated (although they are usually energy constrained and so the water has an opportunity cost i.e., the value of its next best use).

K.5.1 Hydrogen prices

This reference case introduces hydrogen as a fuel type from 2040 onwards. Assuming that new peakers and combined cycle gas turbines built after 2030 are hydrogen-ready, by 2040 all gas turbines transition from natural gas to hydrogen. The assumed hydrogen fuel cost in this reference case is based on the cost curve from AEMO's Hydrogen superpower scenario in its Draft 2022 ISP. We have assumed an added cost for transport of $0.5/kg and storage cost of $0.5/kg. Figure K.20 shows the hydrogen cost curve from 2030 up to 2050.

Figure K.20 Assumed NEM-wide hydrogen fuel cost ($/GJ, real 2021), 2030 to 2050



Source: ACIL Allen

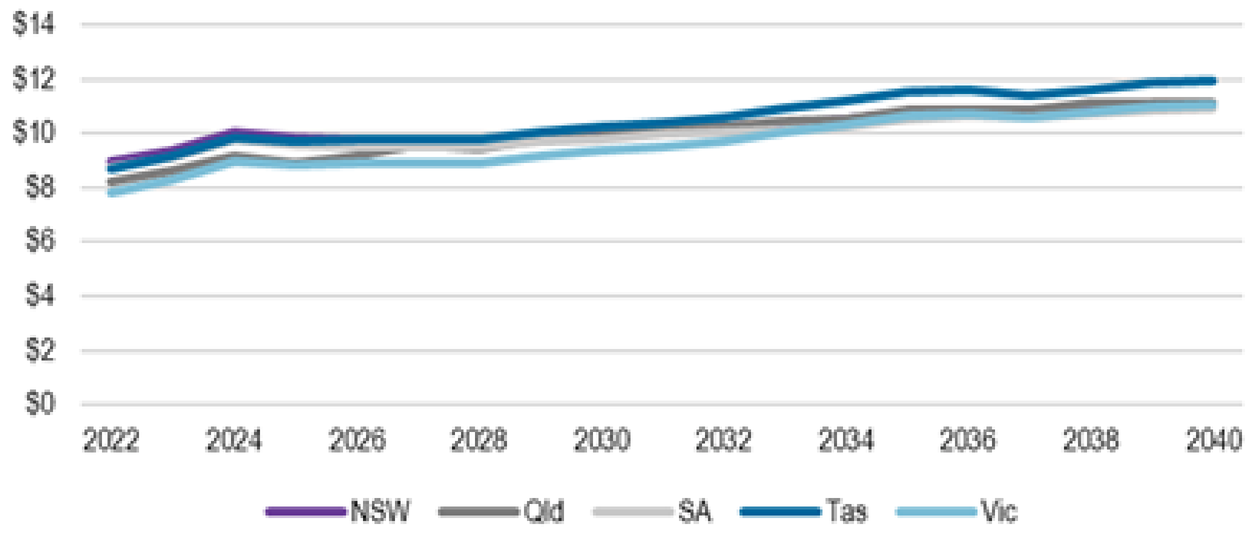
By 2040 the cost of hydrogen has come down to $19.80/GJ and it is assumed that under this cost hydrogen is a commercially viable fuel type option in the reference case.

K.5.2 Gas prices

Assumptions regarding the future price of gas used as fuel for electricity generation are drawn from ACIL Allen's September 2021 Eastern Australia Gas Market Projection report, which utilises modelling undertaken with the firm's GasMark model (noting this was prior to the impact of the current conflict in the Ukraine on gas prices).

Figure K.21 shows the modelled wholesale prices for gas delivered to representative nodes in each region of Eastern Australia under the reference case assumptions for a gas fired combine cycle gas turbine (CCGT). The prices are inclusive of high-pressure gas transmission charges. Prices delivered into peaking plant have a $2/GJ premium added to account for the intermittency of their consumption.

Figure K.21 Assumed wholesale gas prices ($/GJ, real 2021), 2022 to 2040



Source: ACIL Allen's September 2021 Eastern Australia Gas Market Projection report

In the short-term:

— Wholesale gas prices are expected to **edge above $8/GJ from 2022** in most southern markets. Domestic gas prices are now recovering quicker than expected after the impact of COVID-19 in 2020 and early 2021.

— Recovering global oil and LNG demand have been significant factors in driving domestic gas prices upwards. This is resulting in higher international LNG prices which is incentivising LNG proponent to export more gas into the international market.

— Weaker supply expectations from the Gippsland Basin Joint Venture (GBJV) is also projected to lead to slightly higher domestic prices over the short term and into the medium term.

In the medium-term:

— Gas prices are projected to increase to **between $9 and $10/GJ by the mid-2020s** with LNG export demand a primary driver of domestic price outcomes, once again potentially placing pressure on domestic supply.

— Weaker supply from the GBJV is also expected to maintain upward pressure on domestic prices

— However, from the mid-2020s through to the early-2030s, ACIL Allen expects domestic gas prices to then remain relatively stable, **averaging between $9.50-$10.50/GJ**. The following supply is projected to come online and provide some stability to prices:

  – Incremental supply from projects in the Gippsland Basin and the Otway Basin (and some brownfield development in the Gippsland)

  – The development of an LNG import terminal. ACIL Allen anticipates the Port Kembla terminal to now be the first LNG terminal likely to be built with first gas online by 2023.

  – The Narrabri Gas Project by Santos

  – Small volumes of commercial production during this period emerging from the Beetaloo Basin in the Northern Territory.

In the long-term, gas prices are projected to increase gradually in real terms through to the end of the projection period, **reaching levels of between $11-$12/GJ**. The fundamentals of declining reserves from mature gas producing regions and weak long-term investment in supply beyond current projects in feasibility is the major reason for escalating gas prices.

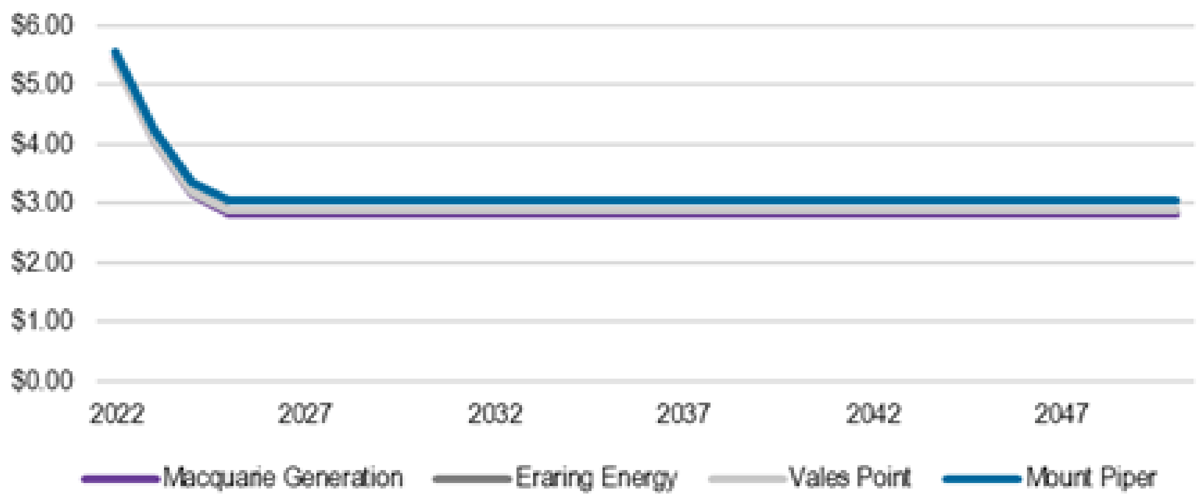
K.5.3 Coal prices

In this report the price of coal for power generation refers to the marginal price of coal.

NSW black coal generators

The delivered marginal coal prices into the NSW coal power stations are assumed to be linked to export parity and therefore follow the assumed movement in export coal prices (see Figure K.22). Eraring and Vales Point are assumed to have the same coal prices. Of the NSW generators, Mt Piper is assumed to incur the highest coal price as it is expected to obtain its supply from the higher cost northern western fields once its current supply from the Springvale mine ceases in the mid-2020s.

Figure K.22 Assumed coal price into NSW stations ($/GJ, real 2021), 2022 to 2050

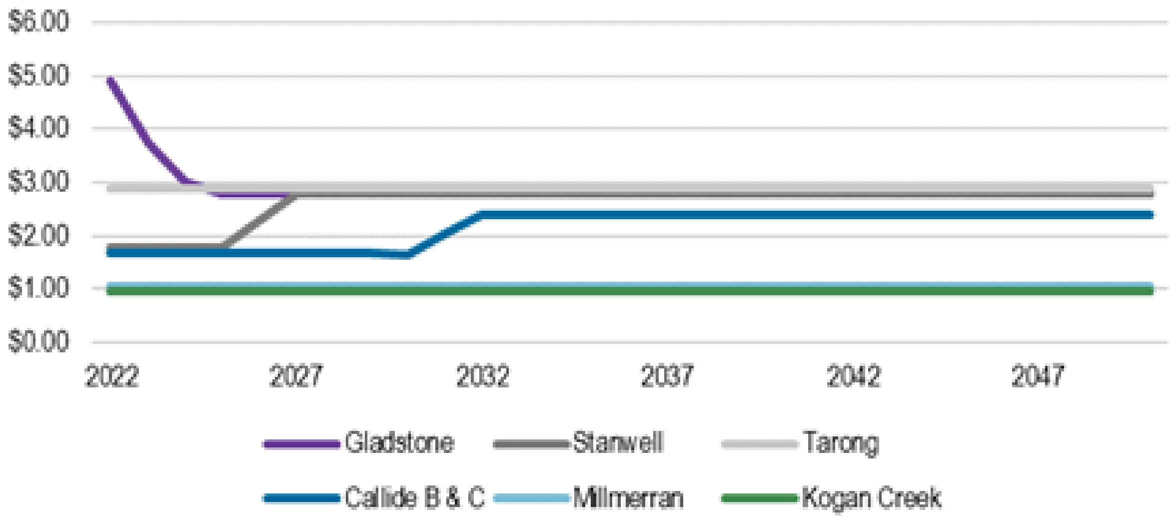


Source: ACIL Allen

Queensland black coal generators

Where domestic prices are exposed to the export coal price, coal prices are similar in Queensland and NSW. However, there is a significant volume of coal from captive mines in Queensland which has noticeably lower prices (see Figure K.23**Figure**).

Figure K.23 Assumed coal price into Queensland stations ($/GJ, real 2021), 2022 to 2050



Source: ACIL Allen

In Queensland there are four types of coal supply arrangement.

Mine mouth – own mine

Power stations in Queensland relying on their own mine mouth coal supply are least likely to be affected by export prices and it has been assumed that they will offer marginal fuel costs into the market. They are Tarong, Tarong North, Kogan Creek and Millmerran.

Mine mouth – captive third-party mine

Callide B and Callide C are power stations with a mine mouth operation with a third-party supplier and are therefore likely to be under pressure to accept higher prices more in line with export parity particularly with price reviews and contract renewal.

Transported from captive third-party mine

Stanwell power station has been in a long-term supply arrangement with the Curragh mine since 2004. In 2018-19, Stanwell signed a new supply agreement which will extend its coal supply to 2038. We have assumed that Stanwell will move to an export parity arrangement which is an imputation of the coal netback price when the current arrangement expires in the late 2020s.

Transported from third-party mine

Gladstone which relies on transported coal from third party mines is most exposed to pass through of export prices. The Callide Boundary Hill mine is the lowest cost potential supplier of coal into Gladstone as this coal has poor yield for export. It is assumed that Gladstone moves to an arrangement where half its future coal supply will be at prices at export parity and half from the lower cost Callide mine.

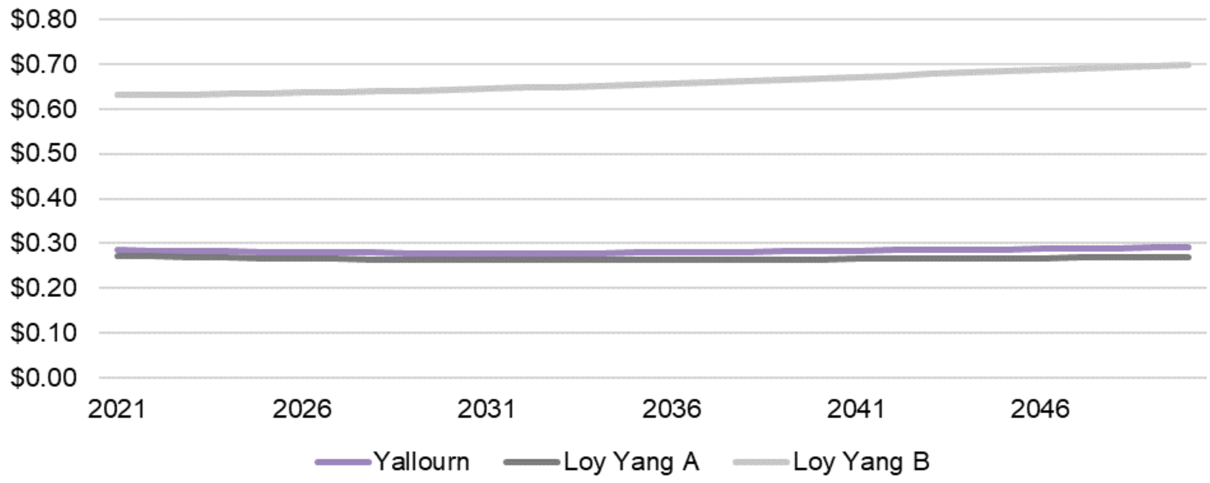
Victorian brown coal generators

Coal mined for power generation in Victoria is not suitable for export and hence not affected by fluctuations in export prices. Extensive deposits of brown coal occur in the tertiary sedimentary basins of the Latrobe Valley coalfield which contains some of the thickest brown coal seams in the world.

Mine mouth dedicated coalmines supply all the power stations. The coalmines are owned by the same entities that own the power stations with one exception: the Loy Yang B power station is supplied by the adjacent Loy Yang Power mine (owned by the owners of the nearby Loy Yang A power station) under a coal supply agreement which expires around 2050.

The marginal price of coal for the Victorian power stations is generally taken as the marginal cash costs of mining the coal (see Figure K.24).

Figure K.24 Projected coal price into Victorian stations ($/GJ, real 2021)



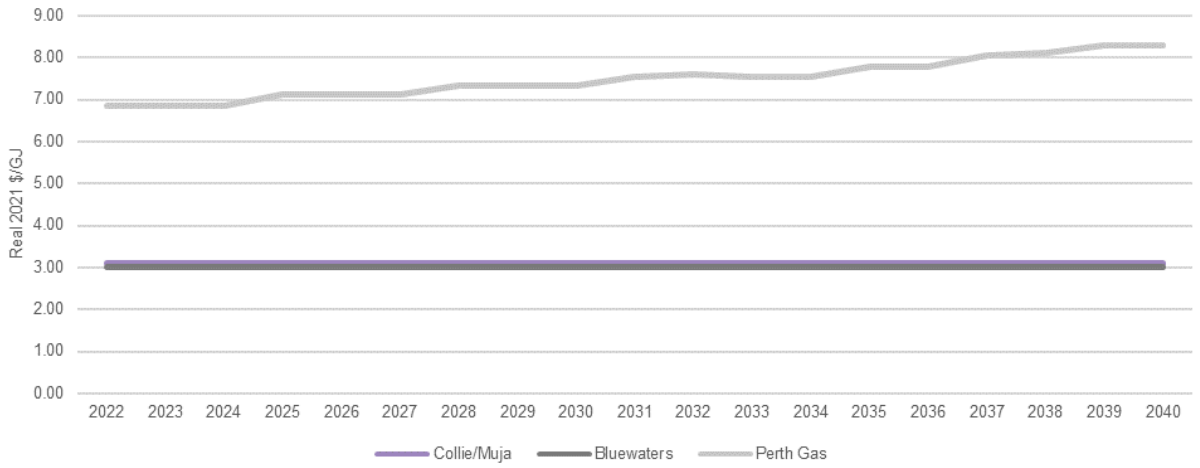
Source: ACIL Allen

K.5.4 Fuel costs in Western Australia

The modelling for Western Australia assumes consistent gas price commodity assumptions for all gas-fired generation. Only variable charges on the Dampier to Bunbury pipeline are included in the generators' short run marginal cost (SRMC). Some variations around this generic gas price series are applied to generators which operate based on legacy contracts such as NewGen, which is assumed to operate on its existing gas contract until expiry.

Figure K.25 summarises the fuel cost assumptions for both natural gas and coal in Western Australia.

Figure K.25 Assumed headline fuel costs in Western Australia, 2022 to 2040



Source: ACIL Allen

K.6 Interconnectors

In the NEM, interconnectors can either be a source of lower priced electricity coming into a region, or a means to export surplus capacity. A summary of the interconnectors and interconnector expansions assumed in the reference case is shown in Table K.5.

K.6.1 Existing interconnectors

This section details the modelling assumptions of existing interconnectors in the NEM.

Assumed capacity

Interregional interconnection capacity assumed in the reference case considers limitations of the transmission system. For this reason, the assumed interconnector capacities may well be less than the capacity of the physical interconnectors.

For example, the total of the physical interconnector capacity between NSW and Queensland is about 1,000 MW – but the location of the interconnectors and the constraints of the NSW grid limits the flow of generation from the Hunter Valley region in NSW to Queensland such that the effective capacity of the NSW to Queensland interconnection is about 600 MW, reducing even further during peak and shoulder periods.

The Basslink interconnector

It is important to mention the difference in operation of the Basslink interconnector compared to other interconnectors in the NEM. Basslink is set in PowerMark as an entrepreneurial interconnector linking Tasmania to Victoria.

Basslink is owned and operated by Keppel Infrastructure Trust. Hydro Tasmania pays an annual facilitation fee for the exclusive right to offer Basslink capacity to the market and receives all spot market revenues (interregional settlements residues). In response to competition concerns, the Tasmanian Government has imposed restrictions on Hydro Tasmania requiring all import capacity to be offered at zero dollars (but for exceptional circumstances) and a prohibition on offering negative prices in either direction.

Therefore, it is bid in a way that attempts to maximise the net revenue of the Hydro Tasmania assets but at the same time accounting for the energy constrained capacity in Tasmania.

K.6.2 New interconnectors and upgrades

All of the interconnector upgrades assumed in the reference case are included in AEMO's 2020 ISP list of "actionable projects". The one exception is the QNI Medium upgrade which is considered by AEMO to be part of the ISP's optimal development path.

AEMO stated in their ISP report (published before the legislation of the NSW Electricity Infrastructure Investment Act) that should the New England REZ development be accelerated through NSW government policy, then it could be expected that works for the NSW side of the interconnector projects such as the QNI Medium could be brought forward as part of the REZ development.

ACIL Allen's own modelling shows that, without an upgrade to the QNI following the deployment of the NSW Roadmap's 12,000 MW of renewable capacity, a non-negligible volume of renewable generation would be commercially curtailed in New South Wales. Given AEMO's comments and ACIL Allen's own findings, it is reasonable to assume that the QNI Medium development would occur to allow increased resource sharing between NSW and Queensland (noting that the current total transfer capability from NSW to Queensland is limited to about 450 MW). We have therefore included the QNI Medium upgrade in the reference case.

The Victorian Big Battery

Before the summer of 2021-22, the capacity of the interconnector between Victoria and New South Wales will be expanded for certain periods of the day. The Victorian Government requested AEMO to undertake a procurement process for a System Integrity Protection Scheme (SIPS) for the Victoria to New South Wales Interconnector. In November 2020 it was announced that Neoen had won the tender to build and operate the 300 MW/450 MWh battery (the "Big Battery") to be installed at the Moorabool Terminal Station in the Geelong region. The battery will provide a service allowing an additional flow of up to 250 MW at peak times across the Victoria-New South Wales interconnector (VNI) from New South Wales to Victoria from late 2021.

It is assumed that in summer months (November to March) the battery provides the SIPS service such that the interconnector capacity is expanded by 250 MW when the price differential between the two regions exceeds $100 / MWh. For the remainder of the year, the battery is assumed to operate commercially in the NEM. This SIPS service is assumed to be available for ten years.

Table K.5 Assumed interconnector capacity

Interconnector	Forward direction	Year	Capacity (MW)
VNI	Vic to NSW	2021	800 (590[a])
		Sep 2022 (VNI Minor)	1,070 (590[a])
Heywood	Vic to SA	2021	460 (500)
		Jul 2024	560 (600)
Murraylink	Vic to SA	2021	220 (180)
Basslink	Tas to Vic	2021	478 (478)
QNI	NSW to Qld	2021	450 (1,100)
		Sep 2022 (QNI Minor)	600 (1,290)
		Jul 2032 (QNI Medium)	1,432 (2,050)
Terranora	NSW to Qld	2021	50 (150)
EnergyConnect	NSW to SA	Jul 2024	800 (800)
VNI West	Vic to NSW	Jul 2026	1,930 (1,800)
Marinus Link	Tas to Vic	Jul 2028 (first link)	750 (750)
		Jul 2032 (second link)	1,500 (1,500)

[a] This is expanded by 250 MW when the SIPS service is operational in summer months (assumed to occur when the price differential between the regions exceeds $100/MWh).

Note: Forward capability, with backward capability shown in brackets.

Source: ACIL Allen analysis of AEMO data

L Wholesale electricity market modelling – demand assumptions

In simple terms, electricity consumption (and peak demand) can be thought of as having the following key components:

1. industrial demand (including energy intensive mining, smelting, LNG extraction and other industrial processes)
2. business or commercial demand (including less energy intensive manufacturing, small and medium businesses)
3. residential demand.

These components describe what we refer to as the *underlying* demand and is influenced by changes in:

— economic and broader market conditions

— price of electricity

— population growth

— adoption of energy efficiency measures.

Each of these components has its own degree of uncertainty. This makes projecting demand for electricity a challenging exercise, as demonstrated by the regularly updated demand forecasts produced by AEMO.

The following pages detail how the electricity demand met by the generators in the NEM is modelled in the reference case, including the impacts of behind-the-meter technologies (rooftop solar PV, battery storage and electric vehicles).

L.1 The demand modelled in PowerMark

PowerMark models the segment of the market to be satisfied by the NEM, that is, by scheduled and semi-scheduled generation. This is the underlying demand less rooftop PV output, plus electric vehicle charging requirements and behind-the-meter storage round trip losses.

PowerMark is run at the hourly resolution level[28] to produce the reference case. This requires an hourly operational demand trace for each region and year of the projection period. The key inputs used by ACIL Allen to produce an hourly demand trace are:

1. An underlying hourly demand trace applicable for the beginning of the projection period
2. Parameters to grow the underlying demand trace for each year of the projection period
3. Hourly rooftop PV, behind-the-meter BESS, and EV charging traces applicable for the beginning of the projection period
4. Parameters to grow the rooftop PV, behind-the-meter BESS, and EV charging traces for each year of the projection period
5. Consideration of any step changes in demand that may not be contemplated in the demand forecast parameters, such as the closure of an aluminium smelter or other industrial load.

L.2 Standardised underlying hourly demand traces for start of projection

It is possible to use the set of actual hourly electricity demands for any of the past recent years and then grow this set to the annual demand projection parameters. However, since demand is affected by weather, the risk of using this approach is to wrongly assume that the weather of the chosen past year is typical and will continue in future years.

Instead of making this assumption, the approach used in creating a set of hourly underlying demands attempts to remove atypical weather effects to produce a demand profile that could be expected given a typical weather pattern.

The simulated hourly demand profile for each region is based on actual underlying hourly demand observations for the previous four years and temperature data dating back to 1970-71. The underlying demands are created by taking the actual operational demands and adjusting for known rooftop PV, BESS and EV uptake. The datasets are used, along with a matching algorithm, to produce multiple sets of weather related underlying hourly demand profiles, from which a single standardised profile is selected.

L.3 Underlying demand projection parameters

A key input in producing the demand trace is the set of annual energy requirements and summer/winter peak demand parameters. Peak demand is the maximum instantaneous demand for electricity placed on the system over a given period, measured in MegaWatts (MW). Energy is the amount of electricity scheduled in the system during a given period, measured in GigaWatt hours (GWh) or MegaWatt hours (MWh). These two inputs broadly describe the energy consumption of the NEM.

[28] It can also simulate the NEM at the half-hourly level.

The reference case makes use of the latest energy and peak forecast produced by AEMO – specifically the forecast based on the medium economic outlook and normal weather conditions (also referred to as the 50 per cent probability of exceedance or P50 peak demand case). This is done by taking the operational demand parameters from the AEMO projection and then adjusting for AEMO's assumed uptake of rooftop PV, BESS and EVs to arrive at a set of underlying demand projection parameters.[29]

Growing the standardised underlying demand traces for each year

The set of standardised underlying hourly demands is scaled for each year of the projection based on the projected underlying demand parameters using a non-linear transformation method.

The outcome of this process is a set of underlying hourly demand values that could be expected given typical weather conditions and the projected growth in demand.

Annual energy requirements and Peak demand from electrification

Part of AEMO's underlying demand trace is the increased energy consumption from the switch from natural gas equipment to electricity. The speed at which this transition takes place differs between the different scenarios that AEMO set up. ACIL Allen assumes a higher rate of transition than is assumed in AEMO's Steady Progress scenario. Though we are using the energy and peak demand forecast from AEMO's Steady Progress scenario, we have replaced the electrification demand in this trace with the electrification energy requirements as part of AEMO's Strong Electrification scenario.

L.4 Projection of rooftop PV uptake

ACIL Allen's projections for uptake of rooftop PV systems, shown in Figure L.1, are a function of payback periods for residential and business customers taking into consideration the number of suitable dwellings, roof-space and saturation levels. Inputs for the uptake model consist of system costs, retail electricity prices and government feed-in-tariffs and upfront subsidies.

NEM-wide, installed capacity is projected to grow from about 12,700 MW in 2021 to about 28,000 MW by 2030.

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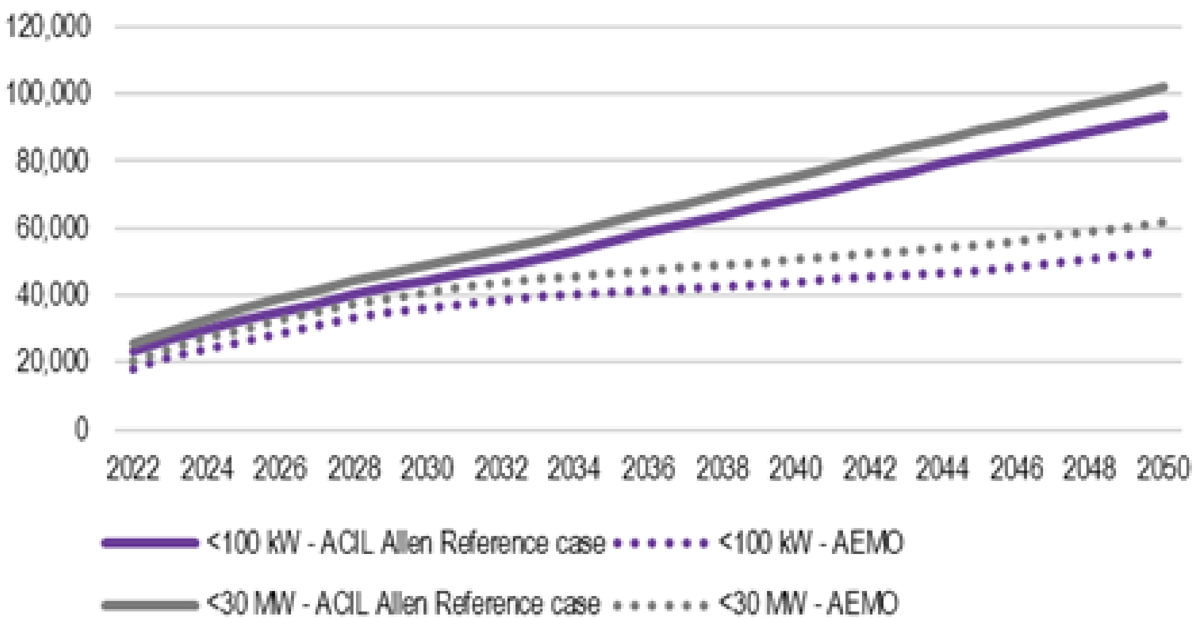
[29] ACIL Allen also deducts an estimate of significant non-scheduled generation from the operational demand parameter to arrive at a scheduled and semi-scheduled parameter (the segment of the market supplied by the NEM).

Figure L.1 Projected cumulative installed rooftop PV capacity by region (MW), 2021 to 2050

Note: Installations less than 100 kW.
Source: ACIL Allen

Figure L.2 compares the NEM-wide projected generation of rooftop PV in the reference case with AEMO's latest projection. The projected generation in the Reference case and AEMO's projection are similar up to 2030. After 2030 the projected uptake of rooftop solar in the Reference case diverges to be about six per cent higher than AEMO, which likely relates to differences in long term projected retail price outcomes (noting that we use our own retail price projections which are internally consistent with the reference case wholesale price projection).

Figure L.2 Comparison of NEM-wide projected rooftop PV generation (GWh), 2022 to 2050



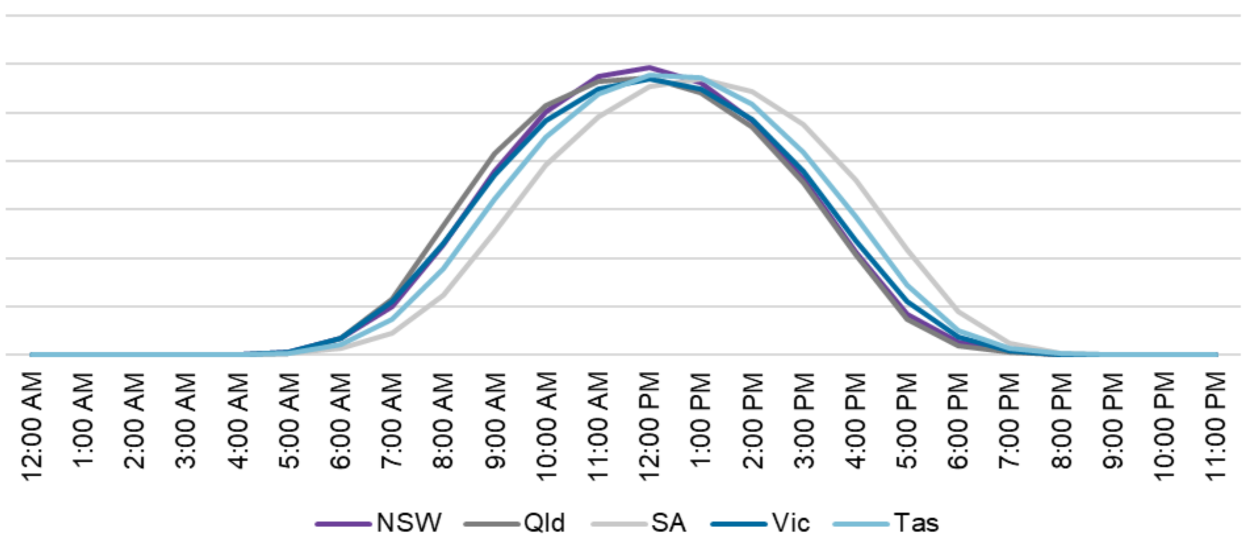
Source: ACIL Allen; AEMO

Growing the rooftop PV generation traces for each year

ACIL Allen has constructed a representative hourly PV output trace for PV systems installed in each region (see Figure L.3). The traces are derived from data on real system output obtained from pvOutput.org. The PV traces are from systems distributed over a wide geographic area which accounts for the diversity of systems installed in each region.

These traces are then scaled to the assumed annual generation parameters. The scaled traces are then deducted from the projected hourly underlying demands.

Figure L.3 Annual average time of day rooftop PV generation profile



Source: ACIL Allen

L.5 Projection of behind-the-meter BESS uptake

Household battery storage systems are currently economically unviable, due to high installation costs, technical limitations relating to depth of discharge and the number of charge/discharge cycles that can be achieved. The number of cycles that can be achieved with a system plays a crucial role in determining its profitability. At a given rate of use, the number of cycles amounts to the system's useful life.

Benefits to end user customers from using an energy storage system include:

— storing solar generation that would otherwise be exported to the grid, thus enhancing the financial value of that electricity to the customer

— avoiding network charges especially charges related to peak network demand charges (noting that most households are not charged for peak demand at present, though this is likely to change in the medium term)

— using lower priced electricity to meet daytime energy demand.

By storing excess solar generation in a BESS, customers forego any payments they would otherwise receive for electricity exported to the network (renewable energy buyback rates or feed-in tariffs). The net benefit to households from storing excess solar generation arises from the difference in the renewable energy export rate and the variable electricity tariff.

In addition to storing excess solar generation, customers who install a BESS and face different tariffs for energy consumption depending on the time of consumption can buy electricity during low price periods and use it when electricity from the grid would be more expensive.

ACIL Allen's assumptions, NEM

ACIL Allen's BESS uptake model relates installation rates of home BESS to the NPV a household achieves by installing such a system. We have assumed that the relationship between NPV and installations rates of home BESS will be similar to the relationship between NPV and installation rates of PV systems which is observable. All existing and future solar installations are assumed to be candidates for the installation of BESS.

The economics of battery installations are also affected by the technical characteristics of battery technology. The nature of battery cycling affects battery life – non-optimal cycling can lead to shorter battery life. We assume daily cycling of the battery with a depth of discharge of 80 per cent and a lifetime of 10 years (equivalent to 3,650 cycles in its lifetime). For our projections we have assumed that battery costs decline by six per cent per annum in real terms.

The projected cumulative installed behind-the-meter BESS capacity in the NEM regions is illustrated in Figure L.4

Figure L.4 Projected cumulative installed behind-the-meter BESS capacity by NEM region (MWh)

Source: ACIL Allen

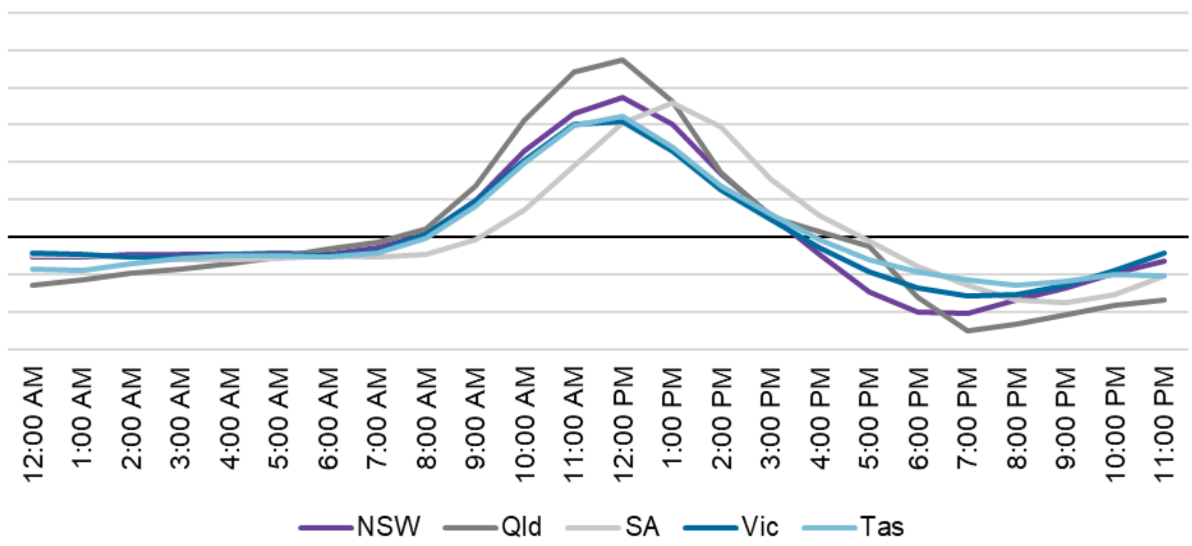
Growing the BESS operation traces for each year

The impact of home energy storage systems will depend on the way these systems are charged and discharged as well as the overall system size.

In the reference case we have assumed that charging and discharging will occur on the basis of a daily cycle where excess solar generation is stored until the storage capacity is reached. Once household electricity demand exceeds solar generation the storage system is fully discharged – typically during the evening peak (see Figure L.5).

Similar to the treatment of rooftop PV, the BESS operation trace is grown and deducted from the projected underlying hourly demands.

Figure L.5 Annual average time of day BESS operation profile, NEM

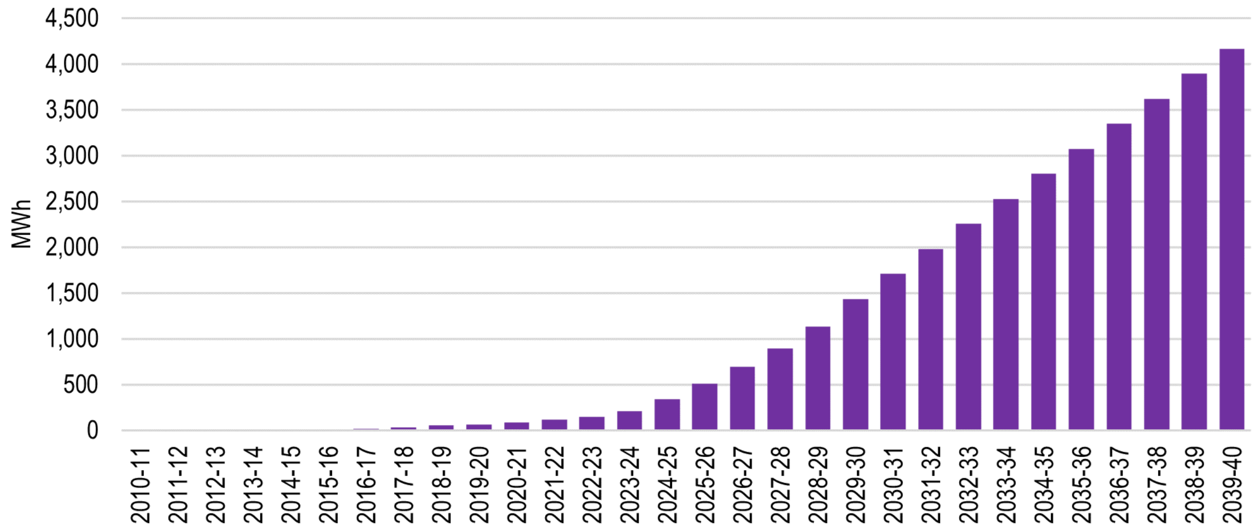


Source: ACIL Allen

ACIL Allen's assumptions, Western Australia

As discussed in appendix K.2.2, ACIL Allen adopts the behind the meter battery projection from the AEMO 2021 ESOO (which extends to 2031) and extrapolates this through to 2040 as shown in Figure L.6.

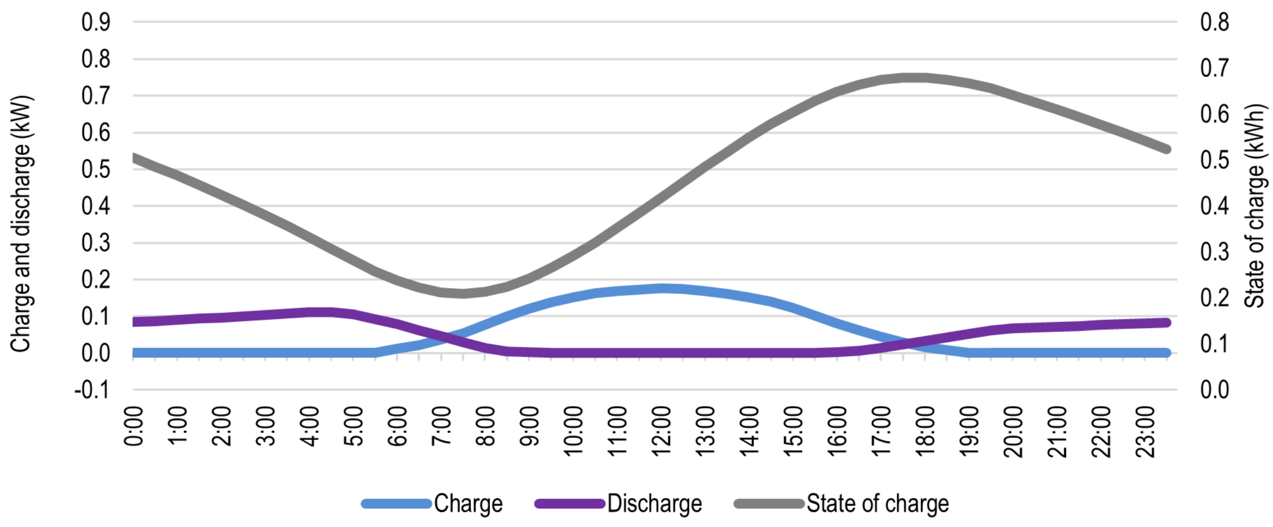
Figure L.6 Behind the meter battery capacity assumed, Western Australia, 2010-11 to 2039-40



Source: ACIL Allen

The underlying charge and discharge profiles are utilised to modify the demand trace at a half-hourly level (see Figure L.7).

Figure L.7 Behind the meter battery charge profile assumed, Western Australia



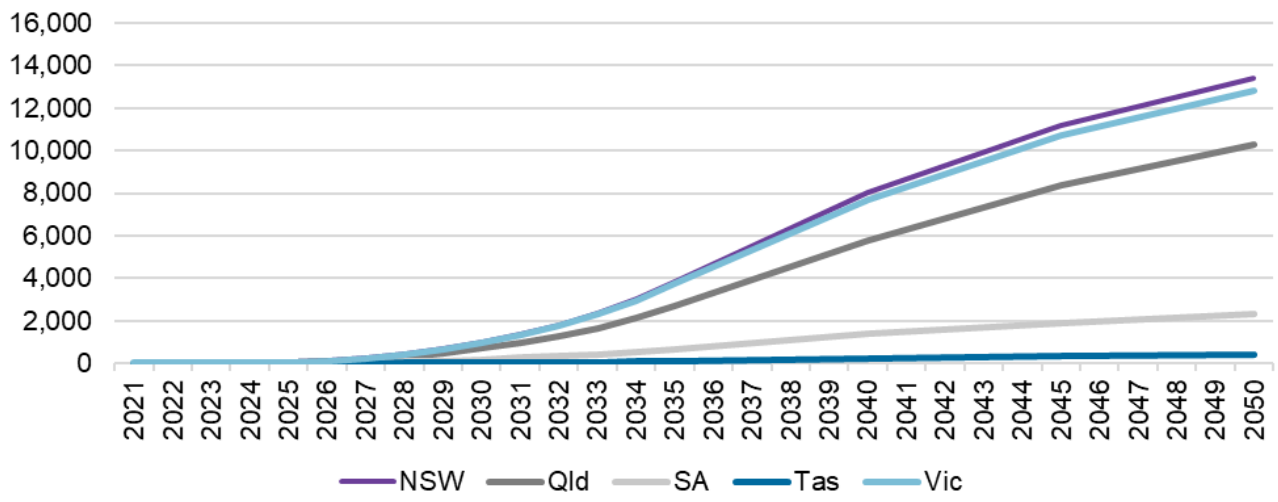
Source: ACIL Allen

L.6 Projection of EV uptake

ACIL Allen has adopted AEMO's projection on the uptake of EVs as published in its latest Draft 2022 ISP. The projected uptake of EV in the NEM suggests little uptake prior to 2030. This is not surprising given the price differential between EV and conventional vehicles at present, as well as the limited choice of model.

However, by 2030, the economics of EV are projected to have improved. This, coupled with various producers announcing moving to EV production only from 2030 onwards leads to a substantial uptake in electric vehicles. The annual contribution of electric vehicles to each region's energy consumption is shown in Figure L.8 and amounts to about 43,000 GWh by 2050 NEM-wide.

Figure L.8 Projected annual energy requirements of EV charging (GWh)

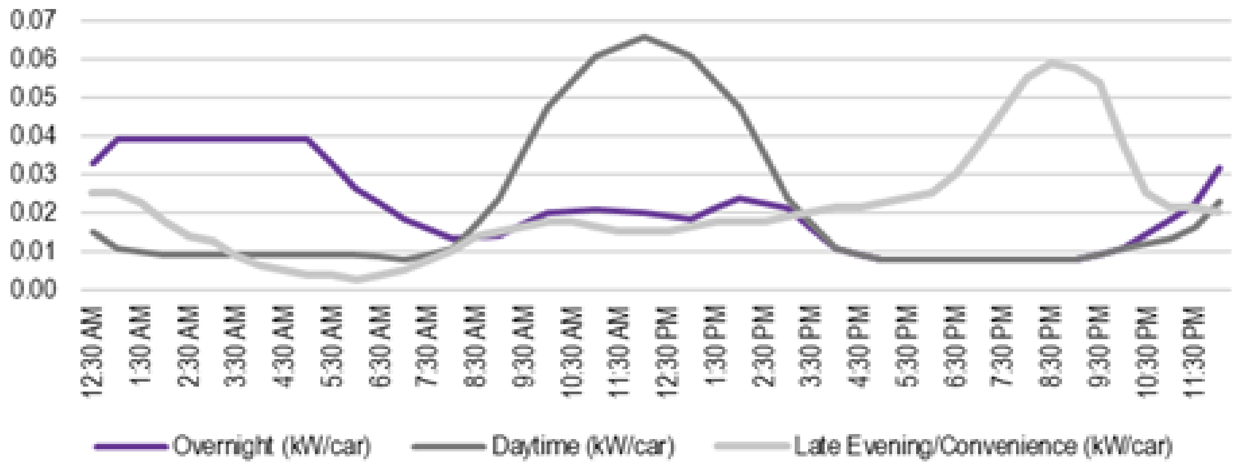


Source: ACIL Allen analysis of AEMO data

Growing the EV charging traces for each year

We have assumed three different charging profiles for EVs, namely a late evening or convenience profile, a daytime profile and an overnight profile (see Figure L.9). The convenience profile has its peak between 18.00 and 22.00, The overnight profile has its peak in the early morning between 1.00 and 5.00 and finally the daytime profile has its peak during the day between 10.00 and 14.00.

Figure L.9 Average time of day EV charging profiles (kW/car)

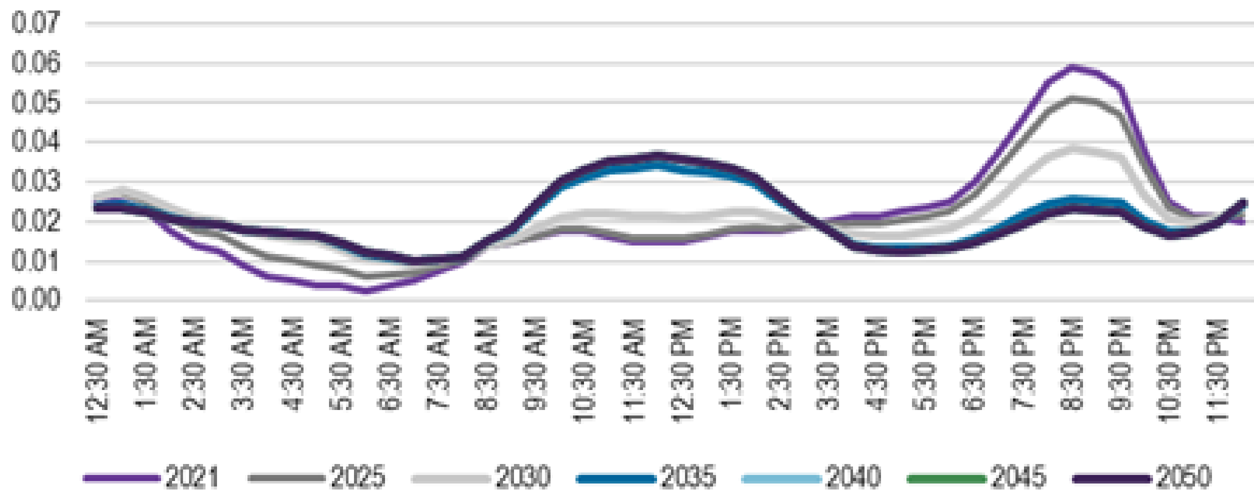


Source: ACIL Allen analysis of AEMO data

The reference case assumes the EV fleet adopts a mix of these charging profiles, and the mix evolves throughout the projection period (see Figure L.10). Initially, the charging regime of the EV fleet is skewed towards the Convenience profile, with most charging occurring over night at households where the EVs are garaged since it is likely that most EV owners charge their EVs at home due to a lack of availability and accessibility of rapid charging stations at different locations.

As charging infrastructure is further developed, charging speeds increase and there is a further evolution in battery swap systems, coupled with electricity tariff reform, we expect a higher proportion of EVs to be charged during the day, allowing them to take advantage of lower daylight hour electricity tariffs. This means that over time the charging profile shifts from a late evening peak to a daytime peak.

Figure L.10 Weighted average combined time of day EV charging profile (kW/car)

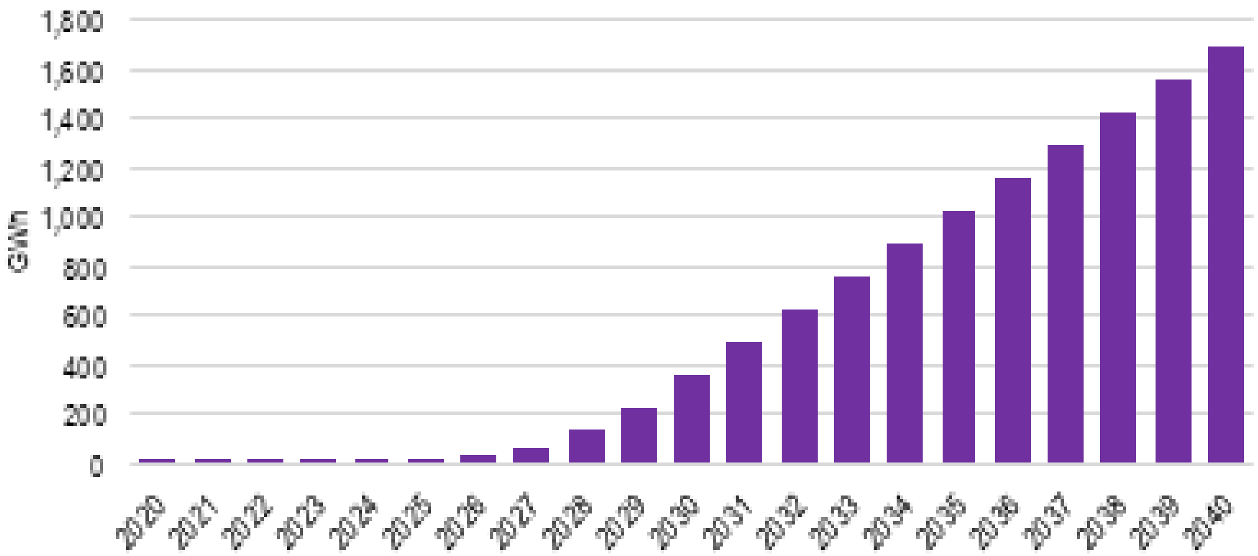


Source: ACIL Allen analysis of AEMO data

EV assumptions, Western Australia

As discussed before, ACIL Allen adopts the EV energy projections from the AEMO 2021 ESOO (which extends to 2031) and extrapolates this through to 2040 as shown in Figure L.11.

Figure L.11 Incremental demand from electric vehicles, Western Australia, 2020 to 2040



Source: ACIL Allen

L.7 Aluminium smelters

The continued operation (or closure) of Australia's aluminium smelters is an important assumption in the demand forecast of the NEM as they are significant consumers of electricity, representing over 10 per cent of the total NEM operational consumption. The latest ESOO central scenario assumes the smelters remain in operation. The reference case makes the same assumption.

Based on analysis ACIL Allen has undertaken in previous engagements with various stakeholders in the aluminium smelting industry, our understanding is that existing smelters in Australia sit in the lower to mid-quintiles of the global supply cost curve at present. This is largely due to competitive power supply contracts, including subsidies for generation and transmission costs.

Our understanding is that should annual time-weighted wholesale electricity prices rise above $50 / MWh on a sustained basis (so as to impact the renewal of their electricity supply contracts), the smelters would be unable to maintain their competitive position in the global supply curve and would therefore be likely to close down their operations.

Given that the projected wholesale prices in the reference case tend to sit below this level out to 2030, as a result of the large volume of additional generation supply (almost exclusively driven by state government policies), the smelters are assumed to continue their operations throughout the projection period. Post 2030, prices are projected to rise above $50 / MWh, however, as has been observed in the past, government subsidies also play an important role in determining whether a smelter continues to operate. It is difficult to determine what the political appetite may be by 2030 to support Australia's aluminium smelting industry. ACIL Allen has therefore aligned with AEMO's demand forecast and kept the smelters operational post 2030.

M Stakeholder consultations

As part of the development of this RIS, ACIL Allen undertook informal consultations during with a limited number of stakeholders to gather stakeholder views about the impacts of proposed amendments to the NCC.

The stakeholders consulted through these workshops are outlined in the table below. Their views and input have been reflected where appropriate throughout the RIS.

Table M.1 Stakeholders consulted during preparation of this RIS

Organisation	Date
Australian Glass & Window Association Building Products Industry Council Lighting Council Illuminating Engineering Society of Australia & New Zealand Insulation Council of Australia & New Zealand Gas Appliance Manufacturers Association of Australia Australian Water Heating Forum Australian Industry Group	Thursday 20 May 2021
Master Builders Association Australian Institute of Architects National Association of Steel Framed Housing Australian Institute of Building Surveyors Master Builders Queensland Master Builders Victoria Property Council	Thursday 20 May 2021
Housing Industry Association	Monday 24 May 2021
Australian Energy Regulator	Tuesday 25 May 2021
Energy Networks Association	Friday 28 May 2021
Australian Energy Market Operator	Tuesday 1 June 2021
Australian Energy Market Commission	Friday 4 June 2021

Source: ACIL Allen.

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