Energeia DER Simulation Platform Technical Report

Prepared by ENERGEIA for the Energy Networks Association

November 2016

Table of Contents

Table of Tables

Table of Figures

Disclaimer

While all due care has been taken in the preparation of this report, in reaching its conclusions Energeia has relied upon information provided by third parties as well as publicly available data and information. To the extent these reliances have been made, Energeia does not guarantee nor warrant the accuracy of this report. Furthermore, neither Energeia nor its Directors or employees will accept liability for any losses related to this report arising from these reliances. While this report may be made available to the public, no third party should use or rely on the report for any purpose.

The modelling results are supplied in good faith and reflect the knowledge, expertise and experience of the consultants involved. Energeia does not warrant the accuracy of the model nor accept any responsibility whatsoever for any loss occasioned by any person acting or refraining from action as a result of reliance on the model. The model is for educational purposes only.

For further information, please contact:

Energeia Pty Ltd
Suite 902, 171 Clarence Street
Sydney NSW 2000

T: +61 (0)2 8097 0070
E: info@energeia.com.au W: www.energeia.com.au

1 Introduction

1.1 Background

CSIRO and the ENA (CSIRO/ENA) are partnering to develop an Electricity Network Transformation Roadmap (ENTR), a blueprint for transitioning Australia's electricity system to enable better customer outcomes. Focused on the next decade, the Roadmap development process involves collaboration with consumer representatives, service and technology providers, policy makers, regulators, and academia with the overall objectives to:

- Update and build upon the CSIRO Future Grid Forum (FGF) work completed in 2013[1]
- Identify new services and technologies that future customers will value
- Identify the options for regulation, business models and electricity pricing that are best able to support delivery of the future services that customers want, while ensuring an efficient, competitive, and economically robust value chain.

As part of this, ENA/CSIRO has engaged Energeia to undertake modelling to understand how market and policy settings have the potential to respond to the challenges of integrating distributed energy resources (DER) to improve customer outcomes.

This report is one of a series of reports produced by Energeia as part of the ENTR, all of which aim to provide the evidence base to underpin recommendations for action by Australia's electricity sector over the Roadmap period.

This report focusses on technical modelling in terms of both the approach adopted, key assumptions and detailed results. The report should be read in conjunction with the Energeia summary reports including:

- Network Pricing and Incentives Reform
- Role and Incentives for Microgrids and Stand Alone Power Systems.

The technical modelling was undertaken by Energeia with inputs and assumptions developed by CSIRO as nominated throughout this document. This report should accordingly also be read in conjunction with the two CSIRO technical reports:

- Future Grid Forum – 2015 Refresh: Technical Report
- Economic Benefits of the Electricity Network Transformation Roadmap: Technical Report

Energeia acknowledges CSIRO for their inputs, guidance, and support in completing the project.

1.2 Purpose of the Technical Report

The purpose of this report is to provide a detailed description of the technical modelling as well as detailed results at the state level. The report is technical in nature and should be read by those seeking to obtain a deeper understanding of:

- The key methodologies, assumptions and inputs and corresponding limitations
- The technical basis underpinning the results and recommendations within the summary reports
- The results themselves including state based differences (only NEM level results are presented in the summary reports).

[1] CSIRO 2015. *Future Grid Forum – 2015 Refresh: Technical Report*. CSIRO report for the Energy Networks Association, Australia

1.3 Structure of the Technical Report

The technical report is structured as follows:

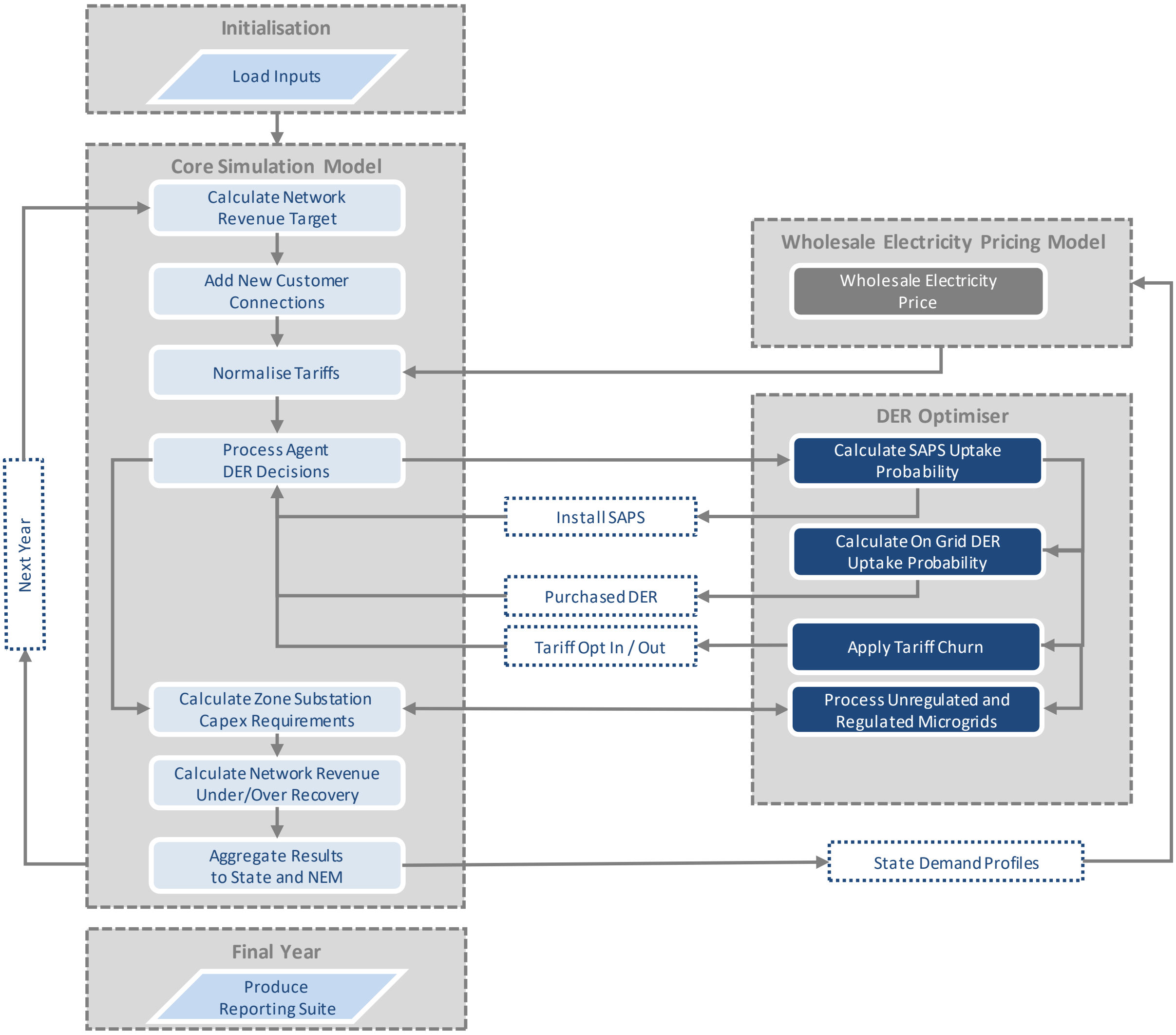
- **Section 1 –** Provides the background and overall objectives of the report
- **Section 2** – Outlines the model structure, and how the calculations flow through different parts of the model and iterate through the calculation process
- **Section 3 –** Provides a summary of the inputs used in the model, at a high level
- **Section 4 –** Provides a summary of the modelling results, at a state level, including a summary of DER and tariff uptake, impacts on network peak demand, cross subsidies, and economic benefits

2 Model Structure

2.1 Overview

Energeia has developed, configured, and operated its Distributed Energy Resource simulation platform to model how various scenarios of market and policy settings influence outcomes in the Australian electricity system. Energeia's DER simulation platform has been used to provide insights into the linkages between tariff reform and energy system response for several studies.

Figure 1 – Overview of DER Simulation Platform



Source: Energeia

2.1.1 Simulation Outcomes

The DER simulation platform seeks to identify how different market and policy settings:

- Incentivise the uptake, sizing, mix and operation of distributed energy resource technology
- Make use of investment in smart meter infrastructure
- Influence network expenditure patterns
- Impact network price rises and consumer bills
- Affect requirements for generation

- Impact the greenhouse gas emission intensity of Australia's electricity system
- Improve the overall economic efficiency of Australia's electricity system in the long-term interest of consumers
- Reduce the extent of cross subsidisation between passive customers and customers who are engaged in distributed energy resource technology and demand management more broadly.

2.1.2 Agent Based Modelling

The DER simulation platform is an agent[2] based model which simulates customer level decision making with respect to DER investment and operation under different tariff, technology, and macro-economic settings, and estimates the corresponding impact of agent decision making on electricity networks investments and wholesale markets.

2.1.3 Scenario Configurations

For the purposes of the NTR, the model was configured per a series of scenarios constructed to assess the relative performance (in terms of economic efficiency and equity outcomes) of:

- network tariff and incentives structures;
- tariff assignment mechanisms, and;
- DER optimisation mechanisms.

Six different scenarios were developed by Energeia in close collaboration with the ENA and CSIRO to represent a range of different longer term outcomes in the electricity market:

2.1.3.1 First Wave Scenarios

- **Scenario 1** – Represents the ***base case*** approach to network tariff and incentive design whereby the current tariff structures, peak and residual charge mechanisms, and tariff assignment mechanisms, as proposed by the DNSPs in their inaugural Tariff Structure Statements, are retained over the period to 2050.
- **Scenario 2** – Has the same assumptions as Scenario 1 with respect to tariff design, but with a slightly more proactive response to the existing network tariff assignment and uptake policies in most jurisdictions. Customers are assigned to maximum demand tariffs and provisioned with advanced metering for all new and replacement customers, including any customer who adopts DER for the first time or additional DER
- **Scenario 3 –** Uses the same tariff design assignments, but with a further proactive increase in response to network tariff assignment and uptake policies whereby all customers are assigned to maximum demand tariffs and provisioned with advanced metering in 2021 on an opt-out basis, meaning customers are still able to select their current tariff, but must actively do so
- **Scenario 3 (Adjusted)** – Has the same proactive increase in network tariff and advanced metering assignment as Scenario 3, but with a restructuring of the residual component of each DNSP tariffs in 2021 at the same time as the opt-out tariff assignment mechanism is implemented to reduce the volumetric kWh component of the tariff.

[2] Agents are the principal decision makers within the simulation. It is the decisions that Agents (and the customers they represent) make that drive network decisions, energy prices and the fate of the grid.

2.1.3.2 *Second Wave Scenarios*

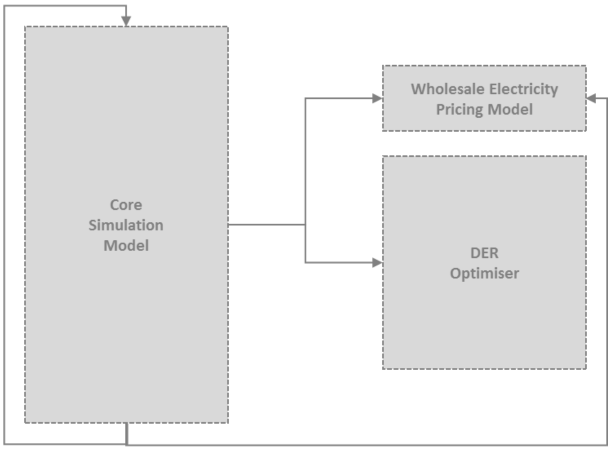
- **Scenario 4 –** Represents a shift to more dynamic tariffs compared to those offered in the current Tariff Structure Statements (but still without any locational signals). Scenario 4 is underpinned by Scenario 3, with the addition of a Critical Peak Price in 2021, offered on an opt-in basis
- **Scenario 5 –** Represents a move towards locational and dynamic pricing mechanisms. Instead of a Critical Peak Price option, the scenario models an incentive structure whereby consumers receive an incentive in exchange for operational access to energy output from batteries at the local level
- **Scenario 6 –** As per Scenario 5, but includes an additional level of sophistication to address any gaps in the level of available DER required to defer augmentation. The scenario enables short-term contracting (up to 3 years) of additional DER in the zone up to the level required for the deferral.

2.1.4 Iterative Approach

The DER simulation platform operates across a range of different functions and modules, through an iterative process year-on-year, for each year of the simulation period. The key modules include:

- **Core Simulation Platform** – Contains the main customer and network function of the models (as outlined in Section 2.2), and is linked to the DER Optimiser and the Wholesale Electricity Spot Pricing Model
- **DER Optimiser** – Calculates the optimal DER configuration for a customer or microgrid given the provided constraints (explained in more detail in Section 2.3), forming a subset of the Core platform
- **Wholesale Electricity Spot Pricing Model** – Sets the wholesale energy component of retail tariffs and the Feed-in-Tariff (FiT) offered by retailers to agents that export solar PV generation (summarised in Section 0).

Figure 2 – Simplified Relationships between Different Model Components



The functions and sub-functions of each of the above modules of the simulation platform are summarised below, including a high level of overview of interactions between different parts of the model, limitations of assumptions and their impact on modelling.

2.2 Core Simulation Platform

The core simulation platform is made up of the main customer and network functions of the model:

- The simulations begin with agents, which use real world customers. Agents are the principal decision makers within the simulation
- The agents are then aggregated to network assets, which are made up of multiple zone substations.

Decisions to purchase DER systems, switch tariffs/incentives or disconnect from the grid are made by agents and zone substations. The results then feed back into network operating and capital costs, which determine network revenue allocations in the following year.

The following sections outline the core simulation platform, and how: inputs and variables are used, target network revenues are calculated, new customers are added, tariffs are normalised, agent decisions are processed, zone substation capex requirements are calculated, results are aggregated, and reports produced.

2.2.1 Inputs and Variables Set-up

Most inputs are loaded directly into the model in their raw form, however, customer data requires pre-processing to be made into usable inputs for the model. The subsections below discuss this customer pre-processing, which begins with define populations and segments, assigning the customers to agents and finally mapping agents to zone substations.

The raw inputs for the model, including the inputs into the pre-processing steps, are detailed in the Section 3.

2.2.1.1 Electricity Customers

The first step in setting up the simulation platform is to generate the residential and commercial customer population connected to the NEM and the SWIS. Energeia worked with CSIRO[3] to develop a data set that included:

- The number of customers on and the load profile of each zone substation
- An estimate of the number of solar PV systems of each zone substation
- The total installed capacity of solar PV on each zone substation
- An estimate of the breakdown of customers on each zone substation by customer class and premise type.

This data was used to define the population of the NEM and SWIS.

Each customer in the population has a set of characteristics, including:

- Parent zone substation
- Customer class (residential or commercial)
- Premise type (house or unit for residential connections and warehouse or suite for commercial connections)
- Annual consumption
- Existing solar PV system size.

The number of customers within each class and premise type on each zone substation is not known with certainty and was estimated by the CSIRO from ABS data. This was cross-checked using RIN data at the zone substation level.

To assign an annual consumption to each customer, a value from a log-normal distribution is selected. The mean value in the distribution is equal to the average annual consumption of the actual customers on the model customer's parent zone substation. This ensures that when there are a reasonable number of customers on a zone substation, the aggregate annual consumption of the model customers closely resembles the annual consumption of the actual zone substation.

Some customers are assigned as existing solar PV customers. The number of solar customers on each zone substation is equal to the estimate of the number of solar PV systems on the zone substation that was provided

[3] More detail on how this data set was constructed can be understood from the complementary CSIRO Technical Report: CSIRO 2016. *Economic Benefits of the Electricity Network Transformation Roadmap: Technical Report*. CSIRO report for the Energy Networks Association, Australia

to Energeia by CSIRO. The size of the system each solar PV customer receives is selected randomly from a log-normal distribution. The mean of the distribution is the average size of the solar PV systems on each zone substation from the estimates that were provided to Energeia.

In total, this process generated more than 9 million unique customers, representing the total customer base within the model.

The key limitations of the customer generation process are:

- Individual model customers do not represent an actual customer connected to a network. Model customers are generated randomly from aggregate characteristics and only match the real-world in aggregate, not individually
- In the real world, there are many more characteristics that customers are defined by, such as whether they have a gas connection, number of occupants, etc.

2.2.1.2 Agents

Modelling each of the more than 9 million customers connected to the NEM and the SWIS is not computationally feasible, so the customer base is represented by a smaller number of agents in the model. Each agent has a unique set of characteristics (Agent Type) and represents a distinct group of customers or population segment. Each agent can represent hundreds of thousands of individual customers.

The process of agent creation and customer assignment has three steps:

- Firstly, agent types are created that cover all the population segments (e.g. possible permutations of load profiles, premise types and existing solar PV), resulting in 6 agent types (see Table 1)
- CSIRO provided 45 customer load profiles for each class of customer (residential or business) for each network, which were assigned to each of the 3 agent types per class, resulting in 135 agents per class.
- Customers were then assigned to the agent within their agent type with closest annual consumption match.
- Finally, additional characteristics of the agents are calculated from the average of the same characteristic of the customers the agent represents, e.g. solar PV system size, rounded to 0.5kW.

Table 1 – Agent Types by Customer Class, Premise Size and Solar PV Usage

		Business Customer Class		**Residential Customer Class**	
		Warehouse	**Suite**	**House**	**Unit**
Solar PV Usage	**Yes**	Agent Type 1	Agent Type 3	Agent Type 4	Agent Type 6
	No	Agent Type 2		Agent Type 5	

The total number of agents per network is therefore 270, composed of 135 per customer class and 45 per agent type, which are defined above.

The limitations of the agent creation process are:

- The range of actual customers' annual consumption is wider than the range of annual consumptions in the load profiles of the agents. This meant that the largest and smallest agents represented all the customers in the tail of the distribution, which in some cases resulted in the agent having a much larger weight within the model than would be preferred
- This also applies to the uneven distribution of agent's annual consumption within the range of extremes. Where three agents have a very similar annual consumption, very few customers will have an annual consumption closer to the middle agent than the other two agents

- All existing DER held by agents was set to have a purchase year of 2015 due to lack of any other information and as a conservative assumption. DER has a limited lifetime and having all agents starting with the same age systems provides no diversity in system replacements.

2.2.1.3 Zone Substations

In the simulation, zone substations are individually modelled. This is because of the importance of zone substations in determining network costs and especially costs incurred by peak demand growth. Peak demand management and reducing the cost of distributing energy is a key focus of the simulation and the zone substation is an important cost component.

In the simulation platform, the term zone substation primarily refers to the substation itself, but also includes related network assets and their associated operating, maintenance and replacement costs. Related assets are modelled on a zero-growth basis (i.e. depreciation = repex) and operating and maintenance costs are fixed over time. Related assets include:

- Upstream sub-transmission feeder lines (defined as the length of line that cannot serve any other zone substation).
- Downstream HV feeder lines
- LV distribution assets.

Each zone substation is assigned a type from the AER classification system: Long Rural, Short Rural, Urban or CBD. The value of all network assets was obtained from each network's most recent Regulatory Information Notice and divided into asset categories. The value of each asset and operating and maintenance costs was normalised by a dividing factor (lines as $/km, vegetation management as $/km, substation value as $/kVA etc.). The assignment of current value and costs was done on a network basis by categories of assets as follows:

- **Upstream Sub-Transmission Feeder Lines –** The value of sub-transmission feeder lines was determined on a $/km basis for the whole network. Each zone substation was assigned a length of line calculated as the straight-line distance to the nearest neighbouring zone substation, using geographic coordinate data provided to Energeia. The left-over km of sub-transmission line was assigned to a shared network assets balancing item
- **Zone Substation Assets** – Zone substation assets were normalised on 2016 $/kVA basis. The Regulated Asset Base (RAB) value and operating expenses were assigned to each zone substation based on its rated capacity.
- **Downstream HV Feeder Lines** – Downstream HV feeder line lengths were assigned equally to each zone substation within a type, i.e. all long rural zone substations had the same length of downstream lines and the associated RAB values and maintenance costs
- **LV Distribution Assets** – LV distribution assets were assigned based on the number of customers on the zone substation, reflecting the largely fixed cost and value nature of these assets

The limitations of zone substations in the simulation are:

- No investment is required for augmentation of HV feeder lines and LV distribution assets over time despite growth in the number of connections
- No new zone substations are allowed by the model, the only method for network expansion is to increase the capacity of existing sites
- Geographic coordinate data was not available for all zone substations or was provided but was obviously inaccurate. In such cases the zone substation was assigned an upstream line length of 0 km.

2.2.2 Calculate Network Revenue Target

The target network revenue represents the revenue that the network aims to recover across all customer classes. It is made up of four components:

- Operating expenses
- Capital costs
- Balancing item
- Adjustment for under or over recovery of revenue in previous years.

The revenue target is calculated at the start of each year modelled using a simplified version of the methodology used by the AER when setting network revenue allowances:

$$Target\ (\$) = Opex\ (\$) + Return\ on\ RAB(\$) + Depreciation\ (\$)$$
$$+Balancing\ Item(\$) + Unders\&Overs\ (\$)$$

The sections below discuss each component of the network revenue target in detail.

2.2.2.1 Operating Expenses

Operating expenses for networks include all operating and maintenance costs. Where these costs can be assigned to individual network assets or categories of assets from RIN data they have been. All remaining operating expenses are assigned to an operating expense balancing item.

2.2.2.2 Capital Costs

Capital costs are made up of two components, return on the RAB and a depreciation allowance:

$$Return\ on\ RAB\ (\$) = RAB\ (\$) * WACC\ (\%)$$

Where:

- The RAB is the RIN estimate for each asset. The WACC is unique to each network and was taken from the most recent AER determination for each network
- The weighted average cost of capital is fixed for each network. This assumes interest rates and the required rate of return on equity in Australia and the risk profile of electricity distribution businesses do not change over time.

Depreciation is calculated by multiplying the RAB value for each asset category by a depreciation rate:

$$Depreciation\ (\$) = \sum^{a} RAB_a\ (\$) * Rate_a\ (\%)$$

Where:

- The depreciation rate is unique to each asset and was calculated using data from each network's RIN by dividing reported depreciation by reported asset value for each category of asset
- This results in the depreciation allowance in the initial model year matching the year the RIN data was collected.

The RAB value for each asset is updated annually by the following formula:

$$RAB_{a,t}(\$) = RAB_{a,t-1}(\$) - Depreciation_{a,t-1}(\$) + Repex_{a,t-1}(\$) + Augex_{a,t-1}(\$)$$

Where:

- For all asset categories, excluding zone substation assets, repex is set equal to depreciation and augex is set to zero so the RAB value does not change. The only exception is when the asset is removed from the network, such as when it is made redundant by a conversion of a zone substation to a microgrid.
- For zone substation assets, a depreciation calculation is only required when replacement or augmentation expenditure is made. For subsequent years, the value of the asset depreciates to zero using straight line depreciation over the course of the assets' life.

2.2.2.3 Under and Over Recovered Revenue from Previous Year

When customers make decisions to change tariffs, purchase DER and move to a stand-alone power solution, the amount of revenue collected by the network will fall short of the revenue target for the year. To protect networks from lost revenue, and consistent with the revenue cap regulatory framework, an allowance is provided to recover the missed revenue during the following year.

$$Under\ and\ Over\ Recovered\ Revenue_t\ (\$) = \big((\$) - Revenue_{t-1}(\$)\big) * (1 + WACC(\%))$$

Where:

- The compensation for missed revenue is increased by the WACC to reflect the missed opportunity to reinvest the revenue that was not recovered in the previous year
- If the network over-recovered revenue during the previous year, this item will reduce the network's revenue in the current year.

2.2.3 Add New Customer Connections

New connections are a key source of demand and consumption growth for electricity networks, and the energy sector as a whole. In the model, new connections are modelled by creating additional agents. One residential and one commercial agent is spawned each year for each network and each is assigned a load profile randomly selected from the 45 profiles available within each class and then assigned to all new connections.

A key characteristic of new connections is that they are assigned to the default tariff for their network. The selection of a default tariff is important because:

- Though new agents will have the opportunity to change tariff immediately, tariff change is dependent upon a bill savings achieved by the tariff change
- Over the model period of 35 years, the population growth rates on some networks result in new customers making up close to half of the final customer base in 2050. Therefore, the assignment of the default tariff has a significant bearing on the penetration of different tariffs on a network.

Agents representing new connections are assigned scaling factors that represent the population of new customer connections on each zone substation. The population growth factors are exogenous model inputs and are unique to each zone substation.

The limitations of this approach are:

- The premise type of the new agent is selected at random from the two options (house/unit or warehouse/suite) with equal probability
- Using only a single agent to represent all new connections in a given year can cause volatility if the randomly selected profile for the new agents is extreme.
- Probability weightings are not applied to demand profile selection so a very large profile has the same probability of being selected as a standard customer profile. This is most noticeable for commercial connections, where the range of customer sizes is wider than for residential.

The model has the capability to generate any number of new agents to increase diversity, but this option was not used to improve model run time.

Under current settings, the number of agents in the model almost doubles by the final year of the model run.

2.2.4 Calculate Tariffs

Tariffs are initially calculated each year to ensure that networks can recover their revenue allowance. The initial calculation formula assumes that there are no changes to the demand profiles of customers during the year (such as load growth, adoption of a Stand-alone-power-system or SAPS, changing tariffs or taking up DER). Under this constraint, the network will exactly recover its regulated revenue.

The limitations of this approach are:

- That customer demand profiles change from the profiles used so revenue recovery will always be different than target
- Tariffs will under-recover whenever the effects of SAPS take-up, changing tariffs and taking up DER are greater than the effect of demand growth
- If per-connection population and demand growth is negative, networks will always over-recover.

The below sub-sections discuss the tariff calculation process. The calculation of the SAPS tariff is discussed separately in the final sub-section due to the unique circumstance of this tariff.

2.2.4.1 Categorisation

The tariff calculation method used in the model requires that revenue targets are set by customer class. The rates for each tariff is set such that the tariffs for each class will fully recover their revenue target if all customers within the eligibility class are on the tariff.

Customers that choose to adopt an off-grid SAPS, or are on a SAPS tariff, are not counted towards the revenue requirement for standard tariffs. This is because they are deemed ineligible to reconnect to the network (SAPs) or revert to a standard tariff (SAPS tariff customers).

For more detail on the SAPS tariff see the SAPS Tariff sub-section below.

2.2.4.2 Peak Revenue Allocation

Networks recover enough revenue from the peak component of the tariff to cover the cost of the contribution to peak demand by each customer class. Peak components are tariff mechanisms that specifically target customers during peak demand periods (these include the peak period of a time of use or maximum demand tariff, critical peak events, and similar components in other tariffs).

The amount of revenue recovered by peak mechanisms across all tariff classes by a network at the zone substation level is:

$$Coincident\ peak\ Revenue\ (\$) = Coincident\ peak\ (kW) * \ \ LRMC(\$/kWh)$$

Where:

- Coincident peak kW is the peak half hour of the load of all residential and commercial customers during the year
- The time of the coincident peak event does not have to be within the peak times defined by the tariffs peak mechanism.

This is then divided between commercial and residential based on the percentage of the peak event that was due to each class.

Each tariff must be able to recover this amount from its peak mechanism such that the rate on the peak mechanism will be:

$$Peak\ Charge\ (\$\ per\ kWh) = \frac{Coincident\ Peak\ Revenue\ (\$)}{Chargeable\ Demand\ (kWh)}$$

Where a tariff has multiple peak components, the relative rates on individual components in 2016 will be kept constant. For example, a calculated tariff based on a network tariff that has both a summer and winter peak, where the summer peak charge is 20% higher than the winter peak charge in the initial year, will retain the 20% premium on the summer peak component.

For tariffs that do not have a peak mechanism, the non-peak mechanisms collect all revenue.

The averaging of different peak components limits peak revenue allocation:

- Where a tariff has multiple peak components, it may have been the intention of the network to have different rates to capture the probability of a peak event occurring during each of the peak times. By maintaining the current rate differential, changes in peak demand patterns will not be captured over time. Future versions will recalculate more complex tariffs automatically.

2.2.4.3 Dynamic Peak Day Calculation (for Certain Dynamic Tariffs)

Critical Peak Periods (CPPs) are set to occur at the same time that network peak events are expected. There is no restriction on when a CPP event can be called, except that two events cannot occur on the same day.

The selection of CPP events[4] requires multiple steps:

- Firstly, generating a network demand profile that excludes the effect of batteries owned by customers on CPP tariffs
- Secondly, ranking every day of the year by the highest demand interval of each day and selecting the top N days (where N is the number of CPP events per annum), before
- Thirdly, finding the peak interval of each of the selected days and setting this as the mid-point of the CPP event
- Finally, setting the start of the event to H/2 intervals before the mid-point and the end of the event to H/2 intervals after the mid-point (where H is the number of hours the event must last for and intervals are of 30min in duration).

To accurately model CPP events, the model must identify when the peak would occur if batteries are not applied to smooth the peak in order to account for the iterative impacts of battery usage on peak definition and the complexities this introduces into the model[5].

2.2.4.4 Residual Allocation

Network revenue that is not recovered through a peak mechanism is allocated to the residual components of a tariff. While some tariffs do not have a peak component, all tariffs have at least one residual component. Residual tariff components are components that do specifically avoid targeting peak demand. The most common types of residual tariff components are a daily fixed charge and an energy charge that is billed on all consumption regardless of time of day (e.g. Ergon's Anytime Energy).

Residual revenue is allocated between customer classes based on the allocation ratio implied by the current tariff settings by each network. As the model progresses, and the value of residual revenue allocated to the network rises, this ratio is retained.

For each tariff, the allocation of residual revenue between different residual tariff components is dependent on the scenario-specific settings applied to each tariff:

- Under the default allocation method, all residual components are grown at the same rate, maintaining the initial year ratios between the different charge rates
- Alternative settings allow and all revenue changes to be assigned to residual components on a fractionary basis.

Residual components charges are set to maintain a ratio of revenues. However, the chargeable quantity for each residual tariff component may change over time, resulting in the revenue ratio between different residual components changing. For example, if a tariff has Fixed and Anytime Energy residual charges and network wide

[4] Only the timing of the event is dynamic. The length and number of events is fixed for a model run.

[5] This is because the batteries can reduce a peak event, which may result in a different interval becoming the new peak. Selecting the new peak rather than the old one would result in batteries no longer being discharged during the original peak, making it into a peak again. Since it was selected first, this peak must be bigger than the one now being clipped by batteries, meaning the network is worse off and may need to invest in additional augmentation. Therefore, the model must identify when the peak would be if batteries were not available.

consumption halved, the charges for both components would rise to recover the lost revenue, but the percentage of revenue recovered from the Anytime Energy charge would halve.

The model has a mechanism for realigning revenue recovery ratios, which is covered in Section 0.

2.2.4.5 Tariff Restructuring

The model contains two mechanisms for restructuring tariffs:

- **Price Rebalancing –** The residual rebalancing mechanism allows the residual tariff prices to be rebalanced so that each component generates a target share of residual revenue. The residual rebalancing mechanism readjusts the relative sizes of the residual charges on a tariff. The purpose of this mechanism is to change the price signals provided by a tariff to test how the structure of residual charges impacts DER uptake.

  The mechanism also corrects for the drift in revenue recovery ratios between the different residual components caused by the tariff calculation. Price based normalisation causes all tariff components to increase in price when revenue from one component falls, such as when customers reduce their grid consumption by using solar panels, causing their anytime energy bill to fall. Since this mechanism is only available at most once per model run, the percentage of revenue recovered by each component will continue to drift from the specified ratio over time

- **Tariff Restructure –** The residual restructure mechanism resets a tariff to have its residual components simplified or standardised. The residual restructure mechanism sets new tariff components, essentially creating a new tariff. It may be used to simplify a tariff by reducing all but one component, e.g. daily fixed charge. For the purposes of the study this was set to replace residual components with a fixed charge and an anytime energy charge, although in theory any restructuring is possible within the model.

Each of these mechanisms are only available once to each tariff in a single model run.

2.2.4.6 Wholesale Energy Prices

Wholesale energy prices are the prices paid for electricity in the National Electricity Market (NEM). Wholesale energy prices are obtained from the Energeia Wholesale Electricity Spot Price Forecasting Model. These prices contribute to customer tariffs in two ways:

- Through the amount paid for the retail tariffs generation cost component
- The amount retailers will pay as a feed-in-tariff (FiT) for rooftop solar PV exports.

The Energeia Wholesale Electricity Spot Price Forecasting Model produces a wholesale market clearing price for each state for each 30-minute interval of a given year. The model uses the demand profile of each state within each interconnected system that is output from the Simulation Platform to determine generator dispatch profiles and prices. The model is described in more detail in Section 0.

Wholesale energy prices are a component of the retail tariff and compensate retailers for the cost of purchasing electricity in the spot market:

- This cost is averaged across all customer classes; residential customers get the same price as business customers
- The wholesale electricity price is applied at the same pass through rate to all peak and non-peak tariff components that are energy based charges.

All tariffs have a Feed-in-Tariff (FiT) component that is available to customers with exports. The FiT rate is set by determining the average $/kWh a solar PV system would earn if it exported all the energy it generated for the year and was paid the wholesale market price in each interval (except where it falls below certain threshold levels).

2.2.4.7 Retail Overhead and Profit

Retail tariffs are the tariffs that customers see and pay. It is assumed that retail tariffs are structurally the same as their corresponding network tariff but with an additional wholesale, fixed and FiT component.

Retail tariffs are determined using an overhead plus profit margin calculation for each component of the tariff using the following formula:

$$\begin{aligned} Retail\ Price\ (\$) = {} & Wholesale\ Price\ (\$) + \\ & Network\ Price\ (\$) * \left(1 + RetailOverheadPct\ (\%)\right) \\ & + RetailProfit \qquad (\$) \end{aligned}$$

Where:

- The wholesale charge is based on energy consumed and is only applied to energy based tariff components
- The retail overhead factor is an additional charge retailers levy on network components. This charge means that as network prices change, retailer margins move in the same direction. This premium is the same for all applicable components of a tariff
- The retail profit margin is an additional charge that is set in the initial year of the simulation and held constant thereafter. Where a tariff is available today, the retail profit value is set so the charges equal those currently available to eligible customers. For new tariffs developed for the project, the retail profit value is an adjustable input.

2.2.5 Process Agent DER Decisions

Agents are the principal decision makers within the simulation. It is the decisions that agents (and the customers they represent) make that drive network decisions, energy prices and the fate of the grid.

Agents go through three different 'decision' processes. Each agent will go through a set of decision making steps to consider moving off the grid, changing tariffs or taking up DER. These decisions are made in a specific order and when a decision to take an action is made the process ends immediately with no further decisions being made.

Each of the individual decisions utilise the DER Optimiser, which determines the optimal DER configuration for an agent subject to the inputs provided. The DER Optimiser also completes a range of other tasks, such as applying technology dispatch algorithms and calculating bills. The DER Optimiser is discussed in detail in Section 2.3.

The following sub-sections discuss the decision-making steps of agents and the decisions they face.

2.2.5.1 Load Growth

Each agent begins the model with a single year demand profile. As the model progresses, this demand profile is adjusted to represent underlying trends in customer electricity demand patterns. This is achieved through the application of two growth factors:

- **Peak Growth** – The growth rate applied to the largest 5% of all half hourly interval loads for a customer
- **Consumption Growth** – The growth rate of total annual consumption for the agent, used for determining the growth rate applied to the lowest 95% of half hourly interval loads

If the peak growth rate is greater than the consumption growth rate, the agent's load profile becomes peakier. Load growth is applied to the customer's original demand profile and so is unaffected by customer decisions, such as tariff, DER and grid independence.

2.2.5.2 Calculate SAPS Uptake

Stand-Alone Power Systems, or SAPS, are microgrids consisting of a single customer. The first decision an agent makes each year is whether to become independent of the grid by installing a SAPS. The SAPS decision involves determining a mix of DER that optimises the cost of the system while minimising unserved energy, capital expenditure, and operating costs.

The optimisation process for SAPS is different to that of a standard grid connected DER system. During the SAPS optimisation, the available technology options have larger maximum sizes and step sizes, diesel generators are available and electricity bills are replaced with a value of unserved energy.

The uptake function for SAPS is the same as the uptake function for an on-grid DER system but with the following additional constraints:

- **Available Technology Options –** Agents are allowed a set of larger DER systems compared to an on-grid DER purchase decision when considering SAPS, which reflects the greater dependence the agent has on DER when they are disconnected from the grid. The number of different sizes of each technology allowed for each agent is the primary contributor to model run time. To contain run time, the larger system sizes available to SAPS are matched with larger step sizes so the number of size combinations is similar to a standard grid connected DER optimisation
- **Diesel Generators –** Diesel generators are only available for SAPS and MGs. Diesel generators have a low capital cost, but this is tempered by high running costs in the form of fuel consumption. Diesel fuel prices include fuel tax rebates that are available when fuel is used for electricity generation. An external fuel price forecast is provided as an input into the simulation that incorporates a range of factors that are expected to drive the cost of diesel higher over time. The fuel price forecast is augmented to include the carbon pricing assumption in the simulation
- **Value of Unserved Energy** – Agents value unserved energy and treat the cost of unserved energy in the same way they treat an electricity bill, minimising the bill to the extent it makes financial sense. The value of unserved energy is derived from Value of Customer Reliability (VCR) figures produced by AEMO. The VCR is a $/kWh figure and is applied to all unserved energy. The VCR is unique to different customer classes and networks, and remains constant in real terms.

In scenarios 3, 3adj, 4, 5 and 6, networks take an active approach to encouraging customers to stay on the grid. In these scenarios, networks offer a semi-disconnected SAPS tariff as an alternative to full grid independence. Networks are incentivised to do this to ensure that their residual costs are recovered. Where residual costs are not recovered due to uptake of off-grid SAPS, residual costs are recovered by remaining customers, creating potential issues for intergenerational equity.

Networks can reduce the impact of off grid SAPS uptake on the bills of remaining customers by allowing customers that are considering off-grid SAPS to maintain a grid connection in exchange for payment of residual charges. In return, the SAPS customers are disconnected from the grid during times of network peak demand. This means that customers on the SAPS tariff do not contribute to the network peak demand event and so are only charged their share of the network residual revenue, less an incentive discount.

The DER Optimiser calculates the best configuration of technologies and whether the best option for the customer is to take up a SAPS tariff (if available). This result is then provided to an uptake function that determines the probability that the agent takes up the configuration.

The uptake function for a SAPS is the same as that for an on-grid DER configuration, but with the additional constraint that the net present value (NPV) of the system must be positive. The uptake function then uses a payback metric to determine the probability of purchasing the system. This probability is then compared to a randomly generated number from a uniform distribution in the range 0 to 1. If the probability is greater than the randomly generated number, the agent makes the purchase.

At this point their decision-making process for the current year is complete and the simulation moves on to the next agent. Once an agent has purchased an off-grid SAPS, they cannot revert to a grid connection. This constraint also extends to customers that switched to a SAPS tariff.

The method used to model SAPS has the following limitations:

- Individual customers' VCRs are much more varied than the single figure being used for all customers in a class for each network. However, due to the agent based approach, including more varied VCR values would increase the number of agents required, which would impact on simulation run time
- The SAPS decision is made using the customer's demand profile in the current year and no allowance is made for future demand growth. If the system was sized correctly for future growth, the SAPS may not be economic and may not have been purchased. This is however considered realistic as a customer is likely to base their decision on current energy needs
- The SAPS decision is made without changes to either energy efficiency or demand response, which are both likely to happen under real world conditions.

2.2.5.3 Calculate On-Grid DER Uptake

The DER uptake decision is made by customers that are connected to the grid. This decision includes the choice by agents to purchase DER, change tariffs or both. The selection of the best DER and tariff combination is done within the DER Optimiser, which selects the combination with the highest NPV based on the inputs provided. An uptake function is then applied to the best option to determine the uptake probability and whether the agent made a purchase. Agents that do not purchase any DER or change tariffs are eligible for the third and final decision making step, tariff churn.

Table 2 – Min/Max/Step Sizes - Solar PV, Batteries, Diesel

Class	Connection Type	Solar PV Size			Battery Size			Diesel Size		
		Min (kW)	Max (kW)	Step (kW)	Min (kWh)	Max (kWh)	Step (kWh)	Min (kW)	Max (kW)	Step (kW)
Residential	On Grid	2	10	2	2	10	2	N/A	N/A	N/A
Residential	Off Grid	2	10	2	4	20	4	1	10	1
Commercial	On Grid	5	25	5	4	20	4	N/A	N/A	N/A
Commercial	Off Grid	5	25	5	8	40	8	10	100	10

The uptake function for a DER purchase is the same as that for a SAPS and constant across states and time. The uptake function uses a payback metric as an input. From this the function produces a probability of the agent purchasing the system. The ROI is calculated by dividing the bill savings achieved by the system by the cost of the system, based on an uptake function parametrised using actual historical solar PV uptake

When an agent's best option is a tariff change only, no investment is made. A second uptake function covers the tariff only case, which calculates an uptake probability based on the agent's bill saving from the tariff change as a percentage of the agent's current bill. The uptake function for a tariff only change results in a considerably lower probability than a DER uptake decision. This is to reflect the low level of observed tariff changes by customers in the current market, despite many customers having the opportunity to make savings on their bills.

There is an additional pathway that determines DER uptake when an agent has a DER system that has reached the end of its life. Except for batteries, it is assumed DER system components fail immediately when they reach a set age. Due to the uptake function, a DER purchase would ordinarily occur with a probability of less than 100%, meaning agents could end up with gaps where they do not own DER. It is more likely that an actual customer would immediately repurchase a DER system after it has failed. To incorporate this behaviour after a DER component fails, the probability of uptake in that year is set to 100% if:

- The purchase has a positive NPV
- The best option includes a purchase of some technology (not only changing tariff)

If an agent purchases a DER system or changes tariff the simulation moves on to the next agent. If the agent did not make a change, they are sent to the tariff churn function.

2.2.5.4 Apply Tariff Churn

Tariff churn is a function that is applied to agents that are connected to the grid and have not purchased a DER system or voluntarily changed tariff in the current year. Tariff churn represents the effect of changes in occupancy at a premise and new and replacement meters. When a customer moves in or out of a house or business premise or the meter on the premise is replaced, the connection is changed to the default network tariff.

Tariff churn is represented in the simulation by switching agents from their current tariff to the default tariff. All other characteristics of the agent are retained, including their load profile and DER systems they have previously purchased. The rate of tariff churn is an input, with values specified for every year, customer class and network. Because of the approach, agents that are already on the default tariff will not change.

For the agents that are potentially subject to this funciton, a random number is generated from a uniform distribution between 0 and 1. If the number generated for a particular agent is lower than the applicable rate of tariff churn for that agent, the agent's tariff is changed to the default tariff.

Regardless of the result of the tariff churn, the agent's decision making process is now complete. The simulation moves on to the next agent.

2.2.5.5 Agent to Zone Substation Scaling/Aggregation

After agents have been processed, the results, including new load profiles, DER quantities and bills, are applied to networks. This process starts by applying the results of each agent to all the applicable zone substations the agent may be related to. Each agent represents a set of real world customers that may be spread throughout the Agent's parent network (see Section 2.2.1.2 for a full explanation).

As the results of each agent are added to the individual zone substations, the results are multiplied by a scaling factor that represents the number of customers the Agent represents that are connected to the zone substation. agent scaling factors vary between zone substations.

2.2.6 Calculate Zone Substation Capex Requirements

The modelled cost of a network is built around the zone substation. As discussed in Section 2.2.1.3, the value of remaining network assets is largely held constant. The exception is the zone substation asset class, which has a set capacity and requires replacement and augmentation as the simulation progresses.

The sections below step through the process of determining the cost of a zone substation. This starts with determining whether the zone substation is in breach of its reliability requirements (see Section 0). If a breach has occurred, a demand profile forecast is generated, which is used in developing a remediation plan.

A network can defer augmentation of a zone substation by:

- Leasing a battery to temporarily reduce peak demand
- Investing in a microgrid solution
- Taking the traditional option and augmenting the substation
- Installing new equipment with higher rated capacities, to meet reliability targets, depending on the options allowed by each scenario.

Zone substations have finite lifetimes due to deterioration in their condition, and when the end of life is reached the substation must be replaced. When this occurs, the same steps are taken as in the augmentation case.

Following the zone substation augmentation/replacement/microgrid decision, information about the zone substation and its customers is aggregated to the parent network. The simulation then progresses on to network level calculations to size and select the least cost solution.

2.2.6.1 Capacity Limits

The simulation assumes all zone substations are rated on an N-1 basis[6]. This assumes individual zone substations have capacity more than their rated capacity but are required to have 100% asset redundancy at all times. The simulation allows for a reasonable amount of exceedance of the N-1 rating. This allowed exceedance is expressed as the number of half hour intervals per year when the demand on a zone substation is greater than its rated capacity. The number of intervals is an input into the simulation.

If a zone substation has not breached a capacity limit and has not reached the end of its life, it takes no further actions for the current year. If this is not the case, the zone substation moves to the next step, which is to calculate a demand forecast.

The method used to model capacity limits has the following limitation:

- Actual installation of N-1 redundancy differs by state, network and within networks. Some areas, such as CBDs, have greater than N-1 redundancy whereas others have no redundancy.

2.2.6.2 Demand Forecast

The construction of a new zone substation or a microgrid firstly requires knowledge about the future demand profile of the asset to be replaced. The chosen construction option must be built large enough to service demand decades into the future. Running the full model to develop a forecast is not computationally feasible given time constraints, so a simplified forecast is used (which also reflects the in-practice approach of network planners who do not have perfect foresight).

A linear extrapolation is used to produce a 20-year forecast of future demand, based on previous years' peak demand growth. In the first four years of the simulation a shortened demand history is used. For forecasts in the initial year of the simulation, when no historical demand is available to create a forecast from, a simulation wide default growth rate is used.

The growth rate derived from peak demand growth is applied uniformly over the asset's interval demand profile to generate a full year profile of half hourly demand for each forecast year.

The method used to forecast demand for determining asset build sizes has the following limitations:

- The forecast is dependent on two data points, current demand and demand growth of (up to) five years previously. If demand is volatile, the forecast may vary widely one year to the next. Therefore, the year when a constraint is breached may have a large influence on the augmented capacity of an asset
- Forecasts in the first few years of the model are unlikely to be representative of the long run given less historical data is available
- DER investment by customers may reduce demand over a period, resulting in a forecast decline, but if penetration of DER is near the maximum the declining demand may not be sustainable. This can lead to zone substation reaching the end of its life being replaced smaller than necessary for the target lifetime and require rebuilding a few years later when demand growth resumes
- All intervals are grown at the same rate. However, it is more likely the growth rate of the maximum value will be more extreme than the average growth rate of the individual intervals. The peak demand could also be declining while total consumption is rising. This issue applies only to microgrids as they use the full demand profile, whereas augmentation of the zone substation only requires sizing based on peak demand.

[6] N-1 refers to having the ability to supply all demand on the zone substation when one set of equipment (transformer, switchgear, sub transmission feeder line etc.) is down.

2.2.6.3 Contracted Battery Option

In scenario 6, networks have the option to lease a battery and place it at a zone substation (or to contract to customers within that zone substation). The battery can be used to remediate shortfalls of the zone substation (due to demand exceeding capacity) by discharging when demand is above the substation's rated capacity.

It is assumed that networks can obtain contracted batteries on a one year lease basis. The battery leasing business requires a higher rate of return on their investment than the network's own WACC and includes an assumption for recovery of depreciation over an assumed battery life. In return, networks gain the flexibility to use the batteries for a short period of time.

Contracted batteries are dispatched with the objective to keep demand on the zone substation below the rated capacity. The contracted battery will only operate to reduce demand to the rated capacity, it will not reduce demand further, solar shift or wholesale price arbitrage. Adding these capabilities to reduce the cost of the network is a future development direction.

The battery in general has no preference in terms of when it charges itself. The exception is when the zone substation has net negative demand caused by large volumes of rooftop solar PV exports by customers of the substation. When negative demand is available the battery will attempt to charge from this to increase minimum demand.

The utilisation rates of contracted batteries are generally very low, only discharging when demand is greater than the rated capacity of the zone substation, occurring a handful of times a year. Due to this low level of utilisation, battery degradation due to cycling is negligible in most cases and so is not included in the pricing function for the battery lease.

The method used to model the contracted battery option has the following limitation:

- Battery lease costs could be lower if the battery could also be used for wholesale electricity price arbitrage in the spot market. This could improve the viability of deferring an augmentation with a grid connected battery.

2.2.6.4 Process Unregulated and Regulated Microgrids

There are two distinct types of microgrids, Unregulated Microgrids and Regulated Microgrids. Unregulated Microgrids are microgrids that are installed by private operators that are not regulated by the AER, whereas Regulated Microgrids are installed by distribution networks and are operated as regulated entities under the guidance of the AER and the National Electricity Rules.

Although the physical structure of the two microgrid options is identical, the economic drivers and available cost savings of the two options differ:

- **Unregulated microgrids –** Unregulated microgrids are a response to an inefficient pricing mechanism that allows a private operator to identify a zone substation where the customers are being overcharged for electricity (including access to the distribution and transmission networks) compared to their cost of supply
- **Regulated microgrids –** In contrast, regulated microgrids take advantage of the potential cost savings from not having to augment or replace a zone substation.

A key difference between the two options in the model is the ownership model and cost base assumed for the downstream distribution assets:

- **Unregulated microgrids –** The operator of an unregulated microgrid must purchase the downstream distribution assets from the network owner. These assets are required to connect all the customers to the microgrid. The simulation assumes that these assets will be made available by networks at their current RAB value. The Unregulated Microgrid operator then takes over the responsibility to maintain the purchased assets and replace them as they reach the end of their operating lives. The network will remove the downstream assets from their RAB[7]

- **Regulated microgrids** – When a network converts a zone substation into a microgrid, the network retains ownership of all affected network assets. As with unregulated microgrids, the zone substation and dedicated upstream feeder line will no longer be used or maintained, but will remain in the networks RAB until each depreciates to zero value. It is the reduced expenditure on operating and replacement of these assets that provides the economic incentive for the network to install a microgrid. The downstream distribution network will be retained and used to service the microgrid.

In each of the scenarios being simulated for the Network Transformation Roadmap, only one of the two microgrid options is available.

The selection of the optimal DER sizes and combinations, for both the regulated and unregulated microgrid, utilises the DER Optimiser. The optimiser is required to find a DER combination that results in zero unserved energy. This reflects the expectation that a microgrid operator, regardless of whether it is a network or a private company, would not be able to obtain the relevant approvals if it could not satisfy the requirement that all electricity demand will be satisfied. Other than this constraint, the optimiser works in an identical fashion as it does to optimise for an individual agent's SAPS.

2.2.6.5 Augment or Replace with New Zone Substation

The traditional response to an ageing or over capacity zone substation is to replace it with a new, correctly sized substation. Despite the new options that are now available, a new substation is still the primary method for maintaining the network and supplying electricity to customers.

The process for constructing a new zone substation in the simulation is the same whether the reason for the upgrade is age or capacity increase. The peak demand forecast for the substation is used to determine an appropriate build size. The build size must be large enough that in the final forecast year the asset will not breach its rated capacity. Then an additional margin is applied to this size and the result is rounded up to the nearest available size.

$$MW_{New} = max\left(PeakMW_t, PeakMW_{t+y}\right) * (1 + margin\ \%)$$

The number of years the forecast is for is an input to the model. Zone substations have a lifetime of up to 50 years, and in some cases longer than this. However, they are typically built to accommodate 20 to 25 years of growth, with an upgrade mid-lifetime to reach the final configuration capacity.

2.2.6.6 Zone Substation to Network Aggregation

Zone substations are treated differently at a DNSP level depending on whether or not they are replaced by a microgrid, and which type of microgrid replaces them:

- **Unregulated microgrids** – If the zone substation has been replaced with an unregulated microgrid, only the value of unused network assets, which depreciate to zero over their remaining lives, are assigned to the network. In the year that the microgrid is installed the network also collects offsetting revenue from assets that were sold to the unregulated microgrid operator. For unregulated microgrids, DER costs are not included in network costs
- **Regulated microgrids** – If the zone substation has been replaced with a regulated microgrid, the demand profiles of customers are treated as if they are still connected to the network. The microgrid customers contribute to network regulated revenue allocations and are used in the tariff normalisation function. The bills of customers that are on a regulated microgrid are treated differently because the

[7] The network will also stop maintaining the now redundant parts of the network, that are have not been purchased by the unregulated microgrid operator. The zone substation and any dedicated upstream feeder lines that previously served the zone substation, although now redundant, remain in the network's RAB and continue to contribute to network revenue allocation. The assets will depreciate over their remaining lifetimes until they are eventually completely removed from the RAB.

network now collects the full customer bill rather than only the network component. Only the network component contributes directly to fulfilling the network's regulated revenue requirement. The additional revenue contributes to total network revenue only. This is the only source on non-regulated network revenue that is calculated in the simulation. For regulated microgrids, DER capex is included within network repex, whereas operating costs are included as part of network opex.

In the case where the zone substation is not replaced, and remains connected to the grid, all customer and networks bills are aggregated to the parent network.

2.2.7 Aggregate Results to State and NEM

The simulation platform works primarily on a network level, with each network operating independently of other networks. This means that agent and network decisions are contained within a single network. The exception to this is the setting of wholesale electricity prices. Wholesale electricity prices are calculated by the Energeia Wholesale Electricity Spot Price Forecasting Model at the state level (see Section 0).

The simulation platform calculates the total electricity demand profile for each state, which is then passed to the wholesale electricity price model. State demand is the sum of industrial, commercial and residential demand in each network in the state from the simulation, plus an additional balancing item for the large scale industrial demand within the state.

Large scale industrial customers are those connected to a zone substation that does not serve any residential or commercial customers, or are connected directly to a sub-transmission line or bulk supply point. These customers are not modelled in the simulation and are only relevant for determining prices in the spot market. The load profiles of large industrial customers do not change over the course of the simulation.

2.2.8 Produce Reporting Suite

The final step of the simulation is to produce the reporting suite. The aim of reporting is to provide a comparison of results across the simulated scenarios. Outputs are produced at the most granular level of the simulation and aggregated to higher levels (individual agents, networks, etc.). Additional calculations are made during the reporting stage to produce estimates of the economic benefits and cross subsidies of each scenario.

Presenting all detailed outputs here is not feasible due to the large number of outputs[8] and so the results presented are limited to state and NEM level.

2.3 DER Optimiser

The DER Optimiser is one of the core modules within the simulation platform and is used throughout the simulation. It calculates the optimal DER configuration for a customer or zone substation given the specified options and constraints.

The DER Optimiser takes a brute force approach, testing every valid combination of technologies, sizes and tariffs that are available for each customer or zone substation.

For each combination of DER and tariff, the first step taken by the optimiser is to apply the behaviour change effect of the tariff in the combination. The optimiser then loops through all the allowable sizes of solar PV, diesel, battery and inverter technologies that are contained in the combination being tested.

With a specific set of explicitly sized DER technologies, the optimiser applies each piece of DER to the demand profile of the customer or microgrid. Solar PV, which is not controllable, is applied first, followed by the battery and then inverter. Finally, if the optimiser is running for a SAPS or microgrid, diesel generators are tested[9].

[8] As an example, a single simulation of one scenario for one network produces more than 50GB of data outputs.

[9] The treatment of diesel generators differs from other technologies in that if the customer or microgrid does not currently have one, a diesel generator of the optimal size for the remaining (after solar and battery) load profile is selected via an

The DER adjusted profile is then used to calculate the customer's retail electricity bill. This bill, plus the cost of DER and value of unserved energy is used to calculate the NPV, payback and other summary statistics for each technology and size combination. From all the combinations, the option with the highest NPV is selected for the customer or microgrid, even when the highest NPV is negative. The payback of this "winning" combination is then used by the uptake function to determine if the customer or microgrid purchases the combination.

Each of the below sections discusses a specific feature within the DER Optimiser in detail. In the sections below a customer can refer to an agent considering a DER system or SAPS or a zone substation considering a microgrid.

2.3.1 Technology and Tariffs Combinations Loop

The first step of the DER Optimiser is to select a combination of tariffs and technologies. A combination is made up of a tariff and, at most, one variant of each DER technology. The combination is tested against some restrictive criteria, such as whether the combination is valid. Examples of an invalid combination are a solar panel without an inverter, a battery with a DER restricted tariff or the customer's current tariff with no DER.

Some technologies can be augmented, with new purchases adding to the existing capacity installed, whereas other technologies must be fully replaced as follows:

- Solar PV and batteries can both be augmented. When a solar PV system is augmented, the system is assigned the life of the new system
- Batteries do not have a remaining life as they deteriorate based on usage
- Inverters and diesel generators must be scrapped when a new system is purchased.

Technology combinations add further complexity:

- Inverters can be retained even as the solar PV systems and batteries they serve are augmented. The customer or microgrid will have the option of purchasing an augmentation option that uses their current inverter or purchasing the augmentation with a new inverter. The existing inverter may become a constraint on the operation of the newly acquired capacity, justifying an inverter upgrade
- If a customer does not currently own a battery, they are required to purchase a new inverter. This constraint is applied to force existing solar customers to purchase a new inverter as most currently available inverters are not compatible with battery storage systems.

2.3.2 Tariff Induced Behaviour Change

The demand profile of the customer or microgrid using the DER Optimiser is first adjusted for the effects of behaviour change. Behaviour change is implemented as a percentage reduction in consumption applied to every half hour interval when peak tariff mechanisms are active. Peak mechanisms that are more concentrated have larger behaviour change effects. For example, the behaviour change effect of a Critical Peak Price tariff, which has a handful of event days each year, has a larger behaviour change effect during peak events than a Maximum Demand tariff that has a peak period on every weekday of the year.

Behaviour change effects are exogenous inputs from previous studies and are applied similarly to classes of tariffs.

The method used to model tariff induced behaviour change has the following limitations:

- Behaviour change is applied to all intervals within the peak period for the tariff, regardless of whether the interval contributed to the total bill for the peak mechanism (i.e. a peak interval with demand of only

algorithm that trades off capital costs for additional unserved energy. This contrasts with the brute force approach that is used for non-diesel DER.

half the current monthly peak will be reduced by behaviour change despite the interval not increasing the customer's bill)

- Behaviour change reduces total customer consumption but does not shift consumption to an off-peak time. In practice, it could be expected that at least some portion of the energy avoided during peak periods would be shifted to off peak times.

2.3.3 Tech Size Combinations Loop

Given a tariff and a set of DER technology variants, the DER Optimiser tests each allowable combination of technology sizes. The allowable sizes are subject to the following constraints:

- Minimum and maximum DER technology size for a single purchase and technology step size
- Customer roof or storage space constraint
- Existing DER technology capacity

The DER Optimiser loops through the sizing and capacity constraints to develop a set of optimum combinations:

- **DER Technology Sizing** – The first three constraints apply to, and are set uniquely for, each DER technology variant. The minimum, maximum and step sizes represent available off-the-shelf sizing options for each technology. As the number of size combinations to test is a significant driver of simulation run time, the size options available have been reduced wherever it does not have a material impact on the results of the simulation
- **Customer Roof or Storage Capacity Constraints** – Roof or storage space are constraints applied to customers based on physical constraints. These constraints limit the total installed capacity of a technology and differ by technology type.

Where a customer has already purchased a piece of DER, they can only augment it up to the size that will fill their remaining space constraint. If the minimum purchase size cannot fit in the customers remaining roof or storage space, no purchase can be made and the current combination will be ruled invalid.

The DER Optimiser loops through all DER sizes sequentially, applying the solar PV, battery, inverter and diesel generator functions described in the sections below, to find the optimum combination of DER.

2.3.4 Solar PV Model

Solar PV is not controllable by its owner and is therefore unaffected by most variables once the size is determined. Due to this, solar PV is the first DER technology that is applied to the demand profile:

- A solar profile trace, multiplied by the size of the solar PV system, is subtracted from the demand profile. The simulation platform contains an annual solar PV output profile for each state. The same profile is applied to all residential and commercial customers and microgrids in the same state and is obtained from the actual output of a representative 1kW solar PV system. Since the profile is from an actual solar system's output, it includes the effects of seasons and weather effects such as cloud cover. Solar profiles do not change between years
- Solar PV systems do not degrade over time but have a finite life and fail immediately when the end of life is reached. However, if a solar PV system is augmented, the new system, including the capacity retained from the old system, will have the lifetime of a new system.

The method used to model solar PV has the following limitations:

- All customers within one state have the same solar profile, which excludes the beneficial effects of geographic diversity on solar PV output. Clouds, which greatly reduce solar PV output, affect all panels within a state simultaneously
- The solar output profile source does not necessarily align to the original dates of the demand profiles that agents in the model have. In many cases, customer and network peak demand occurs on very hot,

sunny days. Since the source data does not align, the network peak event may for example coincide with high cloud cover, rendering solar PV ineffective at reducing peak demand.

2.3.5 Battery

Batteries are used to increase the value of solar PV generation and to arbitrage tariffs by shifting the battery owner's grid demand to times when retail electricity prices are lower.

Batteries have a set of characteristics that limit their ability to complete their objectives:

- **Depth of Discharge** – The depth of discharge (DoD) of a battery is the maximum percentage of the battery's rated capacity that can be used. A battery with a rating of 1kWh and a 90% DoD can be discharged to a minimum level of 0.1kWh. At this point the battery must be recharged. This is a built-in feature by the manufacturer of the battery that improves the lifetime of the battery. Discharging to very low levels has a greater effect on the battery's degradation. However, the manufacturing cost of a battery is driven by the total capacity, which is a function of the volume of materials that go into the final product
- **Output Limits** – Batteries are constrained by how quickly they can be charged or discharged. Higher rates of charging or discharging generate additional heat and degrade the battery faster. The charging and discharging limit is measured by *c*, which is the number of times a battery can be discharged in one hour. For example, a battery with *c*=0.5 can be discharged fully in two hours. In the simulation, the same constraint is applied to both charging and discharging for a battery
- **Losses** – In the simulation, batteries incur losses during charging and discharging. The rate of losses can differ for charging and discharging, but does not vary based on the rate of charging of discharging. These factors are an input into the simulation and can be set uniquely for each battery variant
- **Battery Degradation** – Battery degradation is an important factor in determining the NPV of purchasing a battery. Unlike other DER technologies in the simulation platform, batteries degrade each year. Other DER technologies have a constant maximum capacity/output over their lifetimes and then fail immediately when they reach the end of their lives. Batteries do not have an end of life failure, they continue to operate indefinitely, albeit with a lower level of capacity

  Battery degradation is a factor of two effects, calendar degradation and cycle degradation.

  - *Calendar Degradation* – A decrease in capacity because of age, which is applied as a percentage reduction in remaining capacity at the end of each year
  - *Cycle degradation* – Cycle degradation is caused by battery use and is dependent on the total amount of use the battery gets and how much of its capacity is discharged in a single cycle. A battery that is discharged fully each time it is used will degrade faster than a battery that cycles constantly between 90% and 100% of capacity. Cycle degradation is calculated for each charge, discharge cycle and summed across each year to calculate total degradation as a percentage of initial capacity. Since batteries degrade over time and do not have a finite lifetime, they are assigned a lifetime for the purposes of calculating the net present value (NPV) and payback of a battery purchase. This brings them into line with other DER technologies. The battery lifetime is the number of years until the battery is expected to degrade to 70% of its initial capacity. This is calculated by assuming the battery will degrade at the same rate every year as it did in the first year it was purchased.

The method used to model batteries has the following limitations:

- Each battery variant has the same c[10] for all sizes, which means the model will prefer purchasing a larger capacity battery when the customer needs a battery with a faster rate of discharge
- Only one battery variant is available to each customer class in the simulation so customers are not able to select between different battery characteristics that may be more optimal for a given situation
- There are additional technical factors that affect battery degradation, such as heat and the rate of charging and discharging, that are not incorporated into the degradation calculation
- The degradation calculation always assumes the battery is discharging beginning at 100% but actual degradation depends on how much the battery discharges and the levels the battery is discharging between. For example, a battery cycling between 20% and 30% will degrade more than a battery cycling between 45% and 55%
- Battery lifetime is calculated using a simplified assumption of constant degradation over time. However, degradation will vary over time as the discharge profile of the battery changes. The cause of this variation is due to customer demand changes, other technology purchases and previous degradation of the battery affecting how the remaining capacity can be used.

2.3.6 Battery Algorithm

The battery algorithm determines when the battery charges and discharges. The inputs to the algorithm are:

- The characteristics of the battery
- The size of the inverter
- A demand profile
- A tariff

The battery algorithm aims to lower the battery owner's bill as much as possible by taking advantage of arbitrage opportunities present in the tariff. The algorithm runs across all battery sizes and the battery size associated with the lowest NPV is selected.

The battery algorithm works within the physical constraints of the battery and the inverter. The battery is not allowed to charge or discharge at a rate greater than the inverter size, unless it is charging from solar PV, when it is constrained only by the physical charge limit of the battery. This is because both systems are assumed to be 'behind' the inverter and can operate in DC to DC.

The battery algorithm achieves a near perfect optimisation. There is a trade-off between a perfect optimisation and processing time, which has meant a perfect optimisation has not been used in certain situations. However, for the clear majority of tariffs the algorithm achieves a perfect optimisation.

The algorithm is built based on the battery having perfect foresight of the owner's demand. This means the results of the battery algorithm (excluding a less than perfect optimisation as discussed above) set an upper limit for the savings achievable by a battery in a real-world situation.

The algorithm will reduce a customer's retail electricity bill, starting with the most valuable action and progressing to lower value actions. A high value action is usually discharging in response to a peak mechanism in a tariff, such as clipping demand spikes in response to a maximum demand charge. Lower value actions include arbitraging price differentials for a time of use energy charge, charging during the off peak and discharging during the peak period and then possibly during the shoulder period.

The battery algorithm will charge the battery during the lowest cost time. This is often when there are solar PV exports which have a minimal cost to the customer of the foregone FiT revenue which would otherwise be

[10] A C-rate is a measure of the rate at which a battery is discharged relative to its maximum capacity. A 1C rate means that the discharge current will discharge the entire battery in 1 hour.

received for exports. Some tariffs also have a period where the energy charge is zero, but there is a peak demand charge active. In this case, the battery will charge as much as possible when the energy is free without triggering an increase in the peak demand charge.

The battery algorithm has the following limitations:

- All customers have the same algorithm so often act with a herd instinct, effectively eliminating diversity. Large numbers of customers will charge at the same time, causing new peak demand events
- The battery algorithm is particularly poor at optimising battery activity when a tariff has an inclining or declining block mechanism. This is because the end price for electricity consumption during each tariffing period is not well defined. If a second mechanism exists, such as a peak charge, the algorithm will struggle to determine whether further activity to lower the peak charge is worthwhile.

2.3.7 Inverter

The inverter is assumed to be between the solar PV and battery storage units and the house circuit. The solar PV unit can therefore charge the battery at the same time as it is exporting to the house circuit, which allows solar usage to be greater than inverter capacity. Therefore, the inverter capacity can be smaller than the output of the solar PV unit, and it is assumed the inverter limits power flowing above its capacity, rather than fully disconnecting the solar PV and battery storage system when overloaded.

For this reason, the inverter constraint is applied after the battery algorithm has run to calculate solar generation. The inverter also applies as a constraint within the battery algorithm.

2.3.8 Diesel Generator (Off-grid only)

A diesel generator is available when an agent is considering installing a SAPS or a zone substation is being considered for a microgrid. Diesel generators are a cheap source of backup generation capacity for off-grid systems but have high running costs in the form of diesel fuel costs.

The DER Optimiser utilises an available diesel generator as a back-up power source.

If a battery is part of the microgrid system, the dispatch of the battery will be optimised to ensure the remaining load can be served by the available diesel generator, where possible. This involves the battery trying to clip demand peaks that are higher than the diesel generator's output capacity. The battery can charge from the diesel generator to ensure it has enough charge to clip the peaks.

The treatment of diesel generators in the DER Optimiser differs from other technologies. When determining the optimal size of a diesel generator for an off-grid system, the optimiser does not use a brute force approach. Instead, the optimiser finds a size that will fully satisfy the demand that is remaining after solar and storage systems have been dispatched. This size is equal to the largest remaining peak in the demand profile. The optimiser then uses the relationship between the cost of unserved energy and the variable capital cost of a diesel generator to determine the optimal under sizing for the generator. Most commonly a diesel generator will be sized to satisfy all demand and unserved energy will be zero.

Remaining demand that is not met by the diesel generator then becomes the off-grid system's unserved energy, which has a cost per kWh equal to the value of customer reliability.

2.3.9 Calculate NPV

To compare different technology and tariff combination purchase options, the NPV of each option is used. The NPV formula uses the discount rate of the buyer of the DER system and ongoing payments determined by the DER lifetime and system characteristics as discussed in the sub-sections below. The calculation differs depending on whether the calculation is for an on grid or off grid system. This is because bill savings must be allocated to a source in the former, but not the latter where the bill falls to zero.

The option that has the highest NPV is selected to be analysed by the appropriate uptake function. The decision to purchase the optimal tariff and DER system is dependent on the context of the system and is discussed in detail in Sections 0, 2.2.5.3 and 2.2.6.4.

- **On Grid DER System** – For an on grid DER system the NPV is calculated separately for each component within the combination being tested. This is due to the different lifetimes for each technology, which affects over how many years the capital costs can be spread over.

  Bill savings are applied to different components of an option by calculating the marginal contribution in a pre-specified order. The calculation begins with the customer's existing load profile, including the effect of any technologies they may already own. Then any new technologies, including augmentations, are applied in the following order:

  - *Tariff Change* – The bill effect of a tariff change is applied first. This is only necessary if the option being tested includes a tariff that is different to the customer's current tariff. Because tariffs are easily changeable, the NPV of the tariff change is set to the bill savings (or cost) of the tariff in the current year
  - *Solar PV (including inverter cost)* – Next, the NPV for the solar PV is calculated. This is done by adding the load profile of the new solar PV system to the customer's demand profile (any existing solar PV is already incorporated in the customer's demand profile). The DER optimiser does not consider the possibility that the existing battery of a customer may discharge differently due to the new solar PV and result in additional bill savings. The annual savings are the additional bill savings the owner of the system receives from the solar PV, compared to a tariff change only. The NPV is calculated using the lifetime of the new solar PV system and it is assumed that the bill savings obtained in the current year will be available in each subsequent year. If an inverter is being purchased, the cost of the inverter is included in the solar PV NPV
  - *Battery (including inverter cost if there is no solar PV)* - After the NPV of the solar PV system has been completed, the battery NPV is calculated using the demand profile that includes new solar PV. The battery is calculated after the solar PV because batteries will often utilise solar PV exports to obtain bill savings.

    Because the dispatch profile of a battery will not scale exactly with the size of the battery, the current battery profile of the customer (if any) is subtracted from the demand profile. The new battery profile (which includes existing battery capacity) is then added to the demand profile and the customer's bill is recalculated. The battery NPV is calculated assuming the bill savings obtained in the current year will be received in every future year until the battery degrades to 70% of its new capacity. This lifetime calculation assumes the same degradation every year into the future.

- **Off-Grid DER System** – For an off-grid system, the NPV is calculated by annualising the cost of each technology over its lifetime and then summing these to calculate an annualised system cost. This cost is then discounted over the required lifetime of the system. This lifetime differs by application, for example a zone substation regulated microgrid requires a lifetime equal to the lifetime of a new substation, 50 years.

  Bill savings for an off-grid system are equal to the current retail bill of the customer for a SAPS, the sum of the retail bills for all customers on an unregulated microgrid. Bill savings for a regulated microgrid are set to zero for the purposes of the NPV calculation and the network attempts to minimise the cost of the microgrid. Avoided costs analogous to a bill saving are calculated separately and used in the decision rule for a regulated microgrid.

2.4 Energeia Wholesale Electricity Spot Price Forecasting Model

The Energeia Wholesale Electricity Spot Price Forecasting Model (Spot Price Model) is used to set the wholesale energy component of retail tariffs and the FiT offered by retailers to agents that export solar PV generation.

The Spot Price Model calculates a clearing price for an interconnected system at 30-minute dispatch intervals. The model clears the wholesale electricity market subject to constraints imposed by available generation capacity, interconnectors and bidding behaviour.

The following sub-sections discuss the key functions of the Spot Price Model.

2.4.1 Inputs

The Spot Price Model has three main inputs:

- **State Demand** – Demand profiles for each state, with 30-minute frequency, are provided to the Spot Price Model from the DER simulation platform. The DER simulation platform only covers customers connected to non-industrial zone substations. Because the Spot Price Model requires all demand to be included, a balancing item is added to account for large industrial users that are excluded from the core simulation platform. A balancing item is added to each state, using a representative industrial load trace scaled up so that annual consumption in 2015 equalled actual electricity consumption in each state of the NEM. The balancing item was held constant for all future years
- **Generators** – All electricity generators that are currently in operation in Australia are provided as inputs into the model. Each generator has a set of characteristics, including available capacity, location, fuel type and short run marginal cost (SRMC).

  CSIRO also provided Energeia with plant build out and retirement profiles for all states by generator fuel type. CSIRO developed these build profiles using the same state demand data from the DER simulation platform that was used to run the Spot Price Model
- **Interconnectors -** Interconnectors connect the transmission networks in each NEM state with each other. The Spot Price Model utilises interconnectors to lower prices across the interconnected network by allowing energy to flow from high price states to low price states. In the model, interconnectors have two capacity ratings (one for each direction) and a loss factor. It was assumed that interconnectors remain at current capacities for the full model run.

2.4.2 Generator Bidding

Generator bidding is primarily based on the SRMC of the generator including the cost of carbon emissions by the generator.

As happens in the actual NEM wholesale market, each generator has up to ten bids they can submit. As a simplification, the model only allows bids to be set at the start each year. These bids are then held constant. Each bid is also allocated a percentage of the generator’s capacity, which is also fixed for the full year. This differs from the actual wholesale market where bids and capacity can be adjusted by generators in response to changes in the market.

The value of a bid is a function of the generator’s SRMC and a step-up dollar factor that is unique to each fuel type and a step-up percentage factor that is unique to each fuel type. The step-up factors increase for each bid the generator has, with the tenth bid being the highest.

$$Bid_{gen,i=1\ldots10} = \left(SRMC_{gen} + DollarFactor_{i,fuel}\right) * \left(1 + PercentFactor_{i,fuel}\right)$$

There are two exceptions to this bidding formula. Coal generators will always bid their minimum operating capacity at the market floor. This is their first bid and the remaining nine bids are for the remaining capacity. Nondispatchable renewables will bid their entire capacity at zero dollars as they do not have the ability to control dispatch and have no SRMC.

The capacity component of each bid is set in one of two ways for each generator. The first method uses a historically observed bid breakdown obtained from AEMO data. If that is not available for the generator, a default breakdown applied to each fuel type is used.

Each bid contains sub-bids for each state the energy can be delivered to. These sub-bids differ by losses that are incurred crossing interconnectors.

The key limitations of the generation bidding process are:

- Bids are static not dynamic, in opposition to the real-life situation
- No maintenance (scheduled or unscheduled) or blackouts are modelled

2.4.3 Generator Dispatch

Generators are dispatched per the merit order, subject to interconnector constraints.

The Spot Price Model processes each 30-minute pricing interval independently, meaning there are no constraints on generators based on their current operating level. The most notable limitation of this approach is that hydro generators are assumed to have an infinite storage capacity and are constrained only by the capacity of their turbines. Also, fast start gas units are not afforded any benefits over slow ramp up coal power plants.

Generally, when interconnectors are not constrained, prices in each state will differ at most by the loss factor across the shared interconnector. When an interconnector is constrained the model requires that more expensive local state generators are dispatched (or generators from a state across a second interconnector if the state has multiple connections).

2.4.4 Integration with the DER Simulation Platform

The Spot Price Model is separate from the DER simulation platform but the two systems can be optionally integrated. For the ENTR simulations, the Spot Price Model was only partially integrated into the simulation. A first-round simulation produced demand profiles for all states, scenarios and years. These demand profiles were input into the Spot Price Model, which calculated wholesale prices and FiT prices for all states, scenarios and years. These prices were then used in a second run of the DER simulation. By using a partially integrated approach, there was no feedback from changes in wholesale prices across time.

3 Inputs

This section only covers the inputs and settings that can be adjusted to change the outcome of the simulation. For a full discussion of the inputs and sources for the simulation, see *Future Grid Forum – 2015 Refresh: Technical report*[11] and *Economic benefits of the Electricity Network Transformation Roadmap: Technical report*[12].

Each of the inputs for the simulation can be one of four types. These types are explained in Table 3.

Table 3 – Input Type Categories

Type	Description
Annual	The input is represented by a series of values which change (non-constant growth) over time for each year of the simulation period
Growth Rate	The input is a growth rate that is constant for each year of the simulation period
Initial Value	The input is an initial value which is set for the first year of the simulation and then changes over time, either by a constant growth rate or because of the simulation
Constant	The input is a fixed value that remains constant for the full simulation

Table 4 – Model Inputs

Value	Units	Type	Description	Source
Scenario Settings				
StartYear	Year	Constant	Scenario start year	Energeia + ENA/CSIRO
EndYear	Year	Constant	Scenario end year	Energeia + ENA/CSIRO
DefaultHorizon	Years	Constant	Default horizon value for forward looking decisions when no other value is provided	Energeia + ENA/CSIRO
OffGridForecastYears	Years	Constant	Years of demand growth agents use when sizing a SAPS	Energeia + ENA/CSIRO
NewConnectionMultiplier	#	Constant	Number of agents representing new connections to generate each year	Energeia + ENA/CSIRO
NetworkBatteryControl_StartYear	Year	Constant	Year network takes control of agent owned batteries	Energeia + ENA/CSIRO
Agent Attributes				
Network	Network	Constant	Network	ENA/CSIRO
Region	Region	Constant	Region	ENA/CSIRO
State	State	Constant	State	ENA/CSIRO
Class	Class	Constant	Class	ENA/CSIRO
DwellingType	DwellingType	Constant	Dwelling Type	ENA/CSIRO
DiscountRate	%	Constant	Discount rate Agent applies to future cash flows	ENA/CSIRO
DieselFuelCost	$/L	Annual	Diesel cost faced by agent	ENA/CSIRO
Tariff	Tariff	Constant	Agent's current tariff	ENA/CSIRO
VoltageLevel	LV/HV/ST	Constant	Grid connection voltage	ENA/CSIRO
PeakDemandGrowthPct	%	Growth Rate	Peak demand growth rate	ENA/CSIRO
ConsumptionGrowthPct	%	Growth Rate	Annual consumption growth rate	ENA/CSIRO

[11] CSIRO 2015. *Future Grid Forum – 2015 Refresh: Technical report*. CSIRO report for the Energy Networks Association, Australia

[12] CSIRO 2016. *Economic benefits of the Electricity Network Transformation Roadmap: Technical report*. CSIRO report for the Energy Networks Association, Australia

Value	Units	Type	Description	Source
ExistingSolarSizeKW	kW	Constant	Size of existing solar pv	ENA/CSIRO
ExistingBatteryCapacityKWH	kWh	Constant	Size of existing battery	ENA/CSIRO
AssumedPF	#	Constant	Power factor	ENA/CSIRO
VCR	$/kWh	Constant	Value of Customer Reliability	ENA/CSIRO
RooftopAreaMsq	m2	Constant	Area available for solar pv	ENA/CSIRO
StorageVolumeM3	m3	Constant	Space available for batteries	ENA/CSIRO
GeneratorVolumeM3	m3	Constant	Space available for generators	ENA/CSIRO
SAIDIMIN	minutes	Constant	Minutes of outage the agent expects each year	ENA/CSIRO
Tariffs				
Network	Network	Constant	Network	ENA/CSIRO
Retailer	Retailer	Constant	Retailer	ENA/CSIRO
Region	Region	Constant	Region	ENA/CSIRO
State	State	Constant	State	ENA/CSIRO
EligibilityClass	Class	Constant	The class of customers that can purchase this battery	ENA/CSIRO
EligibilityConsLow	kWh	Constant	Minimum annual consumption for eligibility	ENA/CSIRO
EligibilityConsHigh	kWh	Constant	Maximum annual consumption for eligibility	ENA/CSIRO
EligibilityDemandLow	kW	Constant	Minimum peak demand for eligibility	ENA/CSIRO
EligibilityDemandHigh	kW	Constant	Maximum peak demand for eligibility	ENA/CSIRO
EligibilityVoltageLevel	V	Constant	Minimum voltage for eligibility	ENA/CSIRO
MinYearAvail	Year	Constant	Year tariff becomes available	ENA/CSIRO
MaxYearAvail	Year	Constant	Year tariff is removed	ENA/CSIRO
GrandfatheredYear	Year	Constant	Year tariff is not available to new customers	ENA/CSIRO
LRMC	$/kVA	Constant	LRMC applied to tariff	ENA/CSIRO
RetailOverheadPct	%	Constant	Retail overhead applied to network tariff	ENA/CSIRO
DLF	%	Constant	Distribution loss factor applied to tariff	ENA/CSIRO
NoNewDER	Year	Constant	Customers that purchase DER after this year must change tariff	ENA/CSIRO
NumberOfCPPDays	# events	Constant	Number of CPP events	ENA/CSIRO
CPPDurationHRS	Hours	Constant	CPP event duration	ENA/CSIRO
ResidualResetYear	Year	Constant	Year residual components are reset	ENA/CSIRO
Tariff Components				
TariffID	ID	Constant	Identifies the tariff the component is for	ENA/CSIRO
Type	Fixed/Energy/MD etc.	Constant	Type of charge	ENA/CSIRO
Direction	Import/Export	Constant	Import (Feed in) or Export charge	ENA/CSIRO
Unit	kW/kWh/Days etc.	Constant	Units the charge is applied to	ENA/CSIRO
StartTime	Time	Constant	Time of day component becomes applicable	ENA/CSIRO

Value	Units	Type	Description	Source
EndTime	Time	Constant	Time of day component stops being applicable	ENA/CSIRO
StartDate	Date	Constant	First day of year component is applied	ENA/CSIRO
EndDate	Date	Constant	Last day of year component is applied	ENA/CSIRO
AppliesWorkdays	True/False	Constant	Component is charged on Workdays	ENA/CSIRO
AppliesNonWorkdays	True/False	Constant	Component is charged on NonWorkdays	ENA/CSIRO
Periodicity	D/M/Q/Y	Constant	Length of the tariffing period	ENA/CSIRO
Floor	kW/kWh	Constant	Minimum number of units charged	ENA/CSIRO
Ceil	kW/kWh	Constant	Maximum number of units charged	ENA/CSIRO
Thresh	kW/kWh	Constant	Charge is applied to units above	ENA/CSIRO
Rate	$/unit	Initial	Charge per unit	ENA/CSIRO
PeakRecoveryRatio	%	Constant	Percent of peak target recovered by component	ENA/CSIRO
ResidualRecovery Ratio	%	Constant	Percent of residual target recovered by component	ENA/CSIRO
IsPeak	True/False	Constant	Component is part of a peak mechanism	ENA/CSIRO
BehaviourChange	%	Constant	Customer behaviour change due to tariff component when active	ENA/CSIRO
StopNormalising	Year	Constant	Component rate is fixed after	ENA/CSIRO
Tariffs default				
Network	Network	Constant	Network to which the tariff applies	ENA/CSIRO
Region	Region	Constant	Region to which the tariff applies	ENA/CSIRO
CustomerClass	Class	Constant	Customer Class to which the tariff applies	ENA/CSIRO
DefaultTariffID	Tariff	Annual	Network default tariff assigned to new connections	ENA/CSIRO
ChurnPct	%	Annual	Annual rate of tariff churn	ENA/CSIRO
LRMCNormTariffID	Tariff	Annual	Tariff used for calculating LRMC	ENA/CSIRO
Solar PV Characteristics				
EligibilityClass	Class	Constant	The class of customers that can purchase this battery	ENA/CSIRO
EligibilityDwelling Type	Dwelling Type	Constant	Only customers with the stated dwelling type can purchase this battery	ENA/CSIRO
EligibilityAsset	Customer/Zone Substation	Constant	Broad class availability	ENA/CSIRO
State	State	Constant	State	ENA/CSIRO
MinYearAvail	Year	Constant	Year the product becomes available	ENA/CSIRO
MaxYearAvail	Year	Constant	Year the product is removed from the market	ENA/CSIRO
MinSystemSize	kW	Constant	Minimum purchase size	ENA/CSIRO
MaxSystemSize	kW	Constant	Maximum purchase size	ENA/CSIRO
StepSize	kW	Constant	Step size for purchases	ENA/CSIRO
PhyArea	kW/m2	Constant	Panel size	ENA/CSIRO
Lifetime	Years	Constant	Lifetime	ENA/CSIRO
CostFixed	$	Annual	Fixed component of price	ENA/CSIRO
CostVar	$/kWh	Annual	Variable component of price	ENA/CSIRO
MaintFixed	$/Year	Annual	Fixed annual maintenance cost	ENA/CSIRO

Value	Units	Type	Description	Source
MaintVar	$/kWh/Year	Annual	Variable annual maintenance cost	ENA/CSIRO
Batteries				
EligibilityClass	Class	Constant	The class of customers that can purchase this battery	ENA/CSIRO
EligibilityDwelling Type	Dwelling Type	Constant	Only customers with the stated dwelling type can purchase this battery	ENA/CSIRO
EligibilityAsset	Customer/Zone Substation etc.	Constant	Broad class availability	ENA/CSIRO
MinYearAvail	Year	Constant	Year the product becomes available	ENA/CSIRO
MaxYearAvail	Year	Constant	Year the product is removed from the market	ENA/CSIRO
MinCapacity	kWh	Constant	Minimum purchase size	ENA/CSIRO
MaxCapacity	kWh	Constant	Maximum purchase size	ENA/CSIRO
StepSize	kWh	Constant	Step size for purchases	ENA/CSIRO
PhyVolume	kWh/m^3	Constant	The volume of space taken up by the battery	ENA/CSIRO
CostFixed	$	Annual	Fixed component of price	ENA/CSIRO
CostVar	$/kWh	Annual	Variable component of price	ENA/CSIRO
MaintFixed	$/Year	Annual	Fixed annual maintenance cost	ENA/CSIRO
MaintVar	$/kWh/Year	Annual	Variable annual maintenance cost	ENA/CSIRO
DegredationCalendar	%	Constant	Annual degradation in battery capacity	ENA/CSIRO
DegredationParameters	#	Constant	Parameters of battery use degradation function	ENA/CSIRO
ChargeEfficiency	%	Constant	Energy stored as a percentage of energy spent charging	ENA/CSIRO
DischargeEfficiency	%	Constant	Energy sent out as a percentage of energy depleted from the battery	ENA/CSIRO
MaxOutputC	%/kWh/hour	Constant	Maximum discharge rate of the battery	ENA/CSIRO
InverterID	#	Constant	ID of a bundled inverter (if any)	ENA/CSIRO
EoLCapacityPct	%	Constant	Percentage of the initial capacity when the battery is considered to have reached end of life	ENA/CSIRO
MinDoD	%	Constant	Minimum depth of discharge	ENA/CSIRO
MaxDoD	%	Constant	Maximum depth of discharge	ENA/CSIRO
Inverters				
EligibilityClass	Class	Constant	The class of customers that can purchase this battery	ENA/CSIRO
EligibilityDwelling Type	Dwelling Type	Constant	Only customers with the stated dwelling type can purchase this battery	ENA/CSIRO
EligibilityAsset	Customer/Zone Substation etc.	Constant	Broad class availability	ENA/CSIRO
MinYearAvail	Year	Constant	Year the product becomes available	ENA/CSIRO
MaxYearAvail	Year	Constant	Year the product is removed from the market	ENA/CSIRO
MinSystemSize	kW	Constant	Minimum purchase size	ENA/CSIRO
MaxSystemSize	kW	Constant	Maximum purchase size	ENA/CSIRO
StepSize	kW	Constant	Step size for purchases	ENA/CSIRO
Lifetime	Years	Constant	Lifetime	ENA/CSIRO
CostFixed	$	Annual	Fixed component of price	ENA/CSIRO
CostVar	$/kWh	Annual	Variable component of price	ENA/CSIRO

Value	Units	Type	Description	Source
MaintFixed	$/Year	Annual	Fixed annual maintenance cost	ENA/CSIRO
MaintVar	$/kWh/Year	Annual	Variable annual maintenance cost	ENA/CSIRO
Diesel				
EligibilityClass	Class	Constant	The class of customers that can purchase this battery	Energeia
EligibilityDwelling Type	Dwelling Type	Constant	Only customers with the stated dwelling type can purchase this battery	Energeia
EligibilityAsset	Customer/Zone Substation etc.	Constant	Broad class availability	Energeia
MinYearAvail	Year	Constant	Year the technology becomes available	Energeia
MaxYearAvail	Year	Constant	Year the technology is removed from the market	Energeia
MinSystemSize	kW	Constant	Minimum generator size	Energeia
MaxSystemSize	kW	Constant	Maximum generator size	Energeia
StepSize	kW	Constant	Generator step size	Energeia
PhyVolume	kW/m3	Constant	Size of generator	Energeia
CostFixed	$	Annual	Fixed component of price	Energeia
CostVar	$/kW	Annual	Variable component of price	Energeia
MaintFixed	$/Year	Annual	Fixed annual maintenance cost	Energeia
MaintVar	$/kW/Year	Annual	Variable annual maintenance cost	Energeia
Lifetime	Years	Constant	Lifetime	Energeia
FuelEfficiency	kWh/L	Constant	Fuel efficiency of the generator	Energeia
Policy				
Policy	Carbon Tax/STC etc.	Constant	Identifier	ENA/CSIRO
Value	$/unit	Annual	Value of the policy	ENA/CSIRO
STC				
State	State	Constant	State	REC Registry
DeemedSTCs	#	Constant	Number of STCs per solar pv kW installed	REC Registry
Asset Lifetimes				
AssetType	Zone Substation	Constant	Asset type (Zone Substation only)	ENA/CSIRO
LifetimeYears	Years	Constant	Lifetime	ENA/CSIRO
Zone Substation Build Cost				
Network	Network	Constant	Network	ENA/CSIRO
Build_Margin	%	Constant	% additional capacity to build as a buffer	ENA/CSIRO
BuildOutYears	Years	Constant	New capacity must meet demand forecast for this many years	ENA/CSIRO
Build_Min_KVA	kVA	Constant	Minimum build size	ENA/CSIRO
Build_Step_KVA	kVA	Constant	Step size for new build	ENA/CSIRO
Build_Cost_Fixed	$	Annual	Fixed cost	ENA/CSIRO
Build_Cost_KVA	$/kVA	Annual	Variable cost	ENA/CSIRO

4 Outputs

The results below present the findings of Energeia's modelling at the State level.

The results are presented as followed for each state over the period to 2050 unless stated otherwise:

1. **Residential Tariff Penetration** – Compares the penetration of different tariff classes and off-grid among residential customers by scenario for selected years
2. **Commercial Tariff Penetration** – Compares the penetration of different tariff classes and off-grid among commercial customers by scenario for selected years
3. **Total DER Capacity** – Compares the total installed capacity of each DER type across all scenarios for selected years
4. **Total Peak Demand** – Compares peak demand across scenarios for all years. Peak demand is defined as the sum of the non-coincident peaks on each zone substation.
5. **Economic Benefits 2026** – Compares the economic benefits of each first wave scenarios to the base case over the period to 2026. The economic benefits are made up of wholesale electricity costs, network costs and DER technology costs. The sum of these costs are the total expenditure by electricity users and provides the most complete comparison of different scenarios.
6. **Economic Benefits 2050** – Compares the economic benefits of each scenario to the base case over the period to 2050
7. **Cross Subsidies 2026** – Compares the value of cross subsidies of each first wave scenario to the base case over the period to 2026. Cross subsidies refer to where a customer, following a decision to purchase DER and/or change tariffs to reduce their electricity bill, receives a discount on their bill that is not equal to the cost savings the network receives. The cross subsidies reported from the simulation only arise from customer network bills only. Savings in the retail component of bills that do not produce corresponding savings in the wholesale market are assumed to be absorbed as net costs to the retailers and so are not transferred to customers in the same way as allowed for regulated networks. Cross subsidies are cumulative and are reported undiscounted.
8. **Cross Subsidies 2050** – Compares the value of cross subsidies of each scenario to the base case over the period to 2050

4.1 Residential Tariff Penetration

Figure 3 – Queensland Residential Tariff Penetration

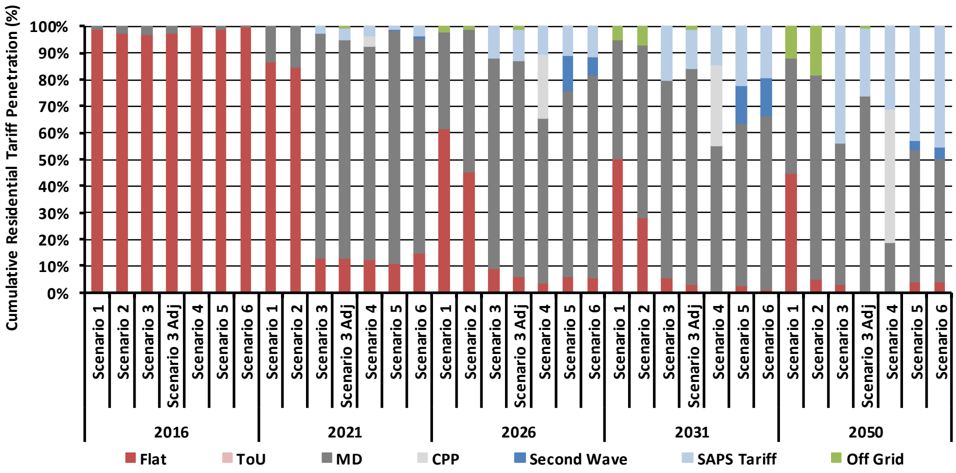


Figure 4 – NSW Residential Tariff Penetration

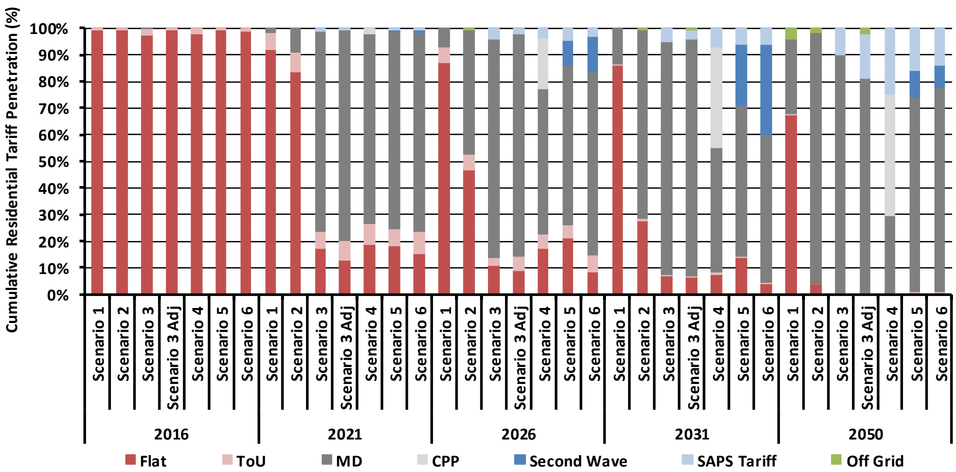


Figure 5 – Victorian Residential Tariff Penetration

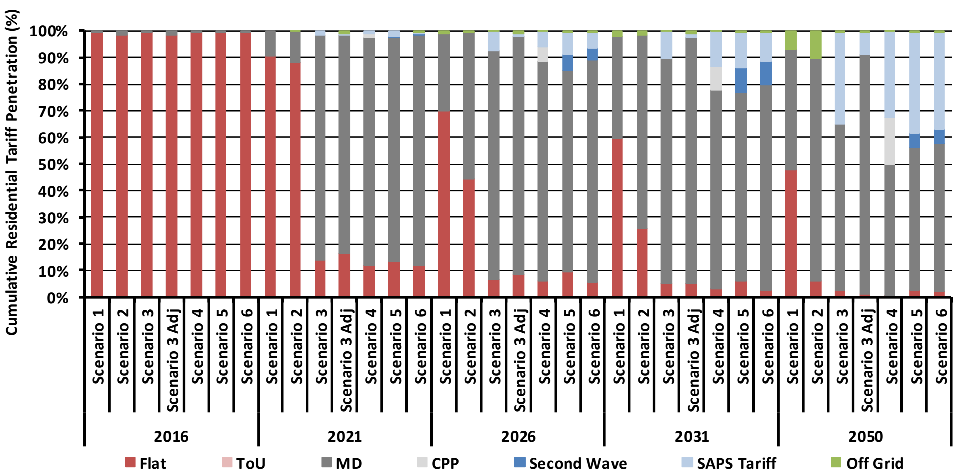


Figure 6 – South Australian Residential Tariff Penetration

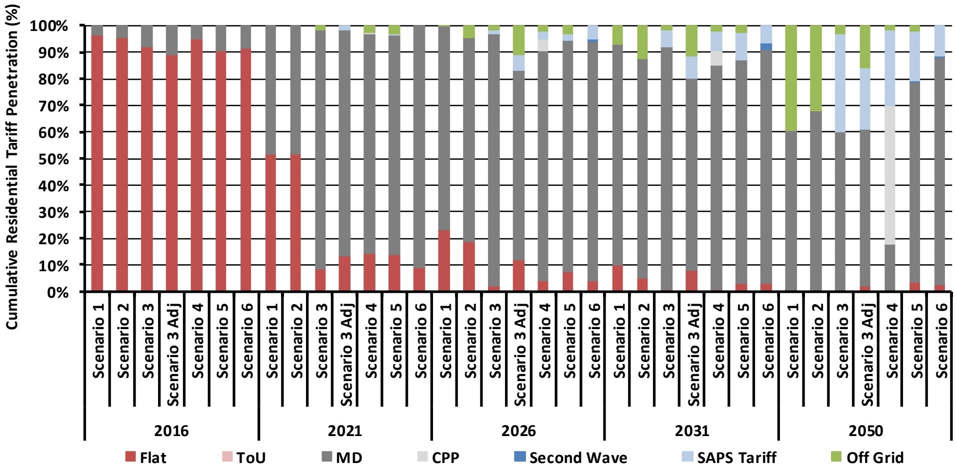


Figure 7 – Tasmanian Residential Tariff Penetration

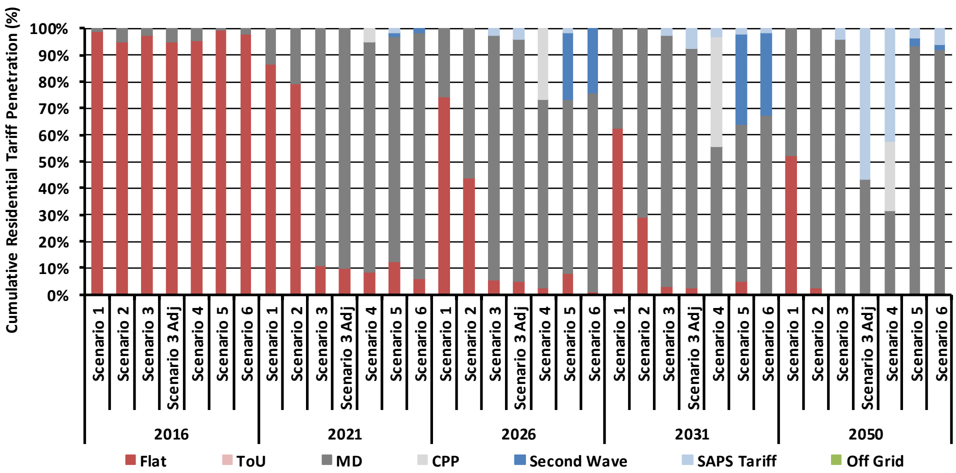
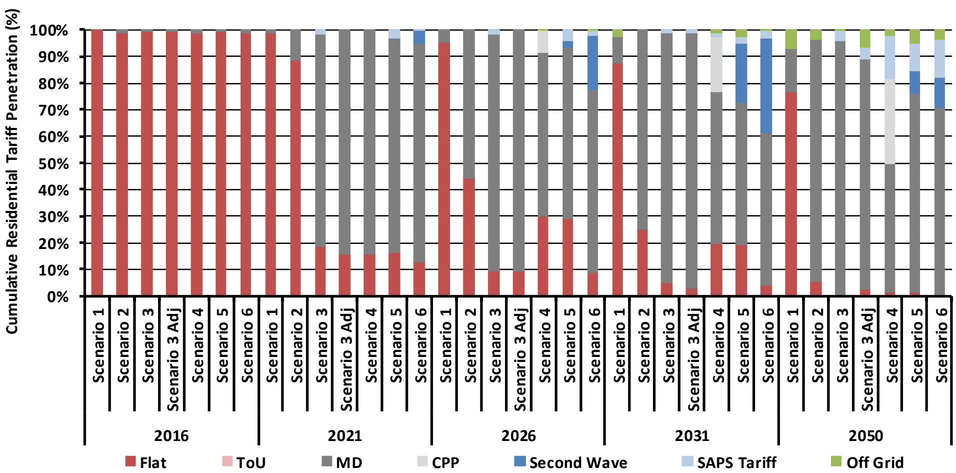


Figure 8 – West Australian Residential Tariff Penetration



4.2 Commercial Tariff Penetration

Figure 9 – Queensland Commercial Tariff Penetration

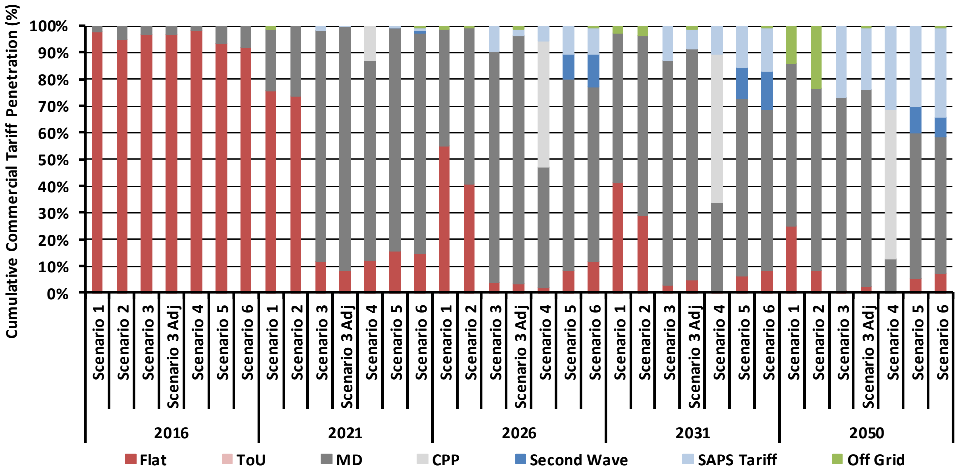


Figure 10 – NSW Commercial Tariff Penetration

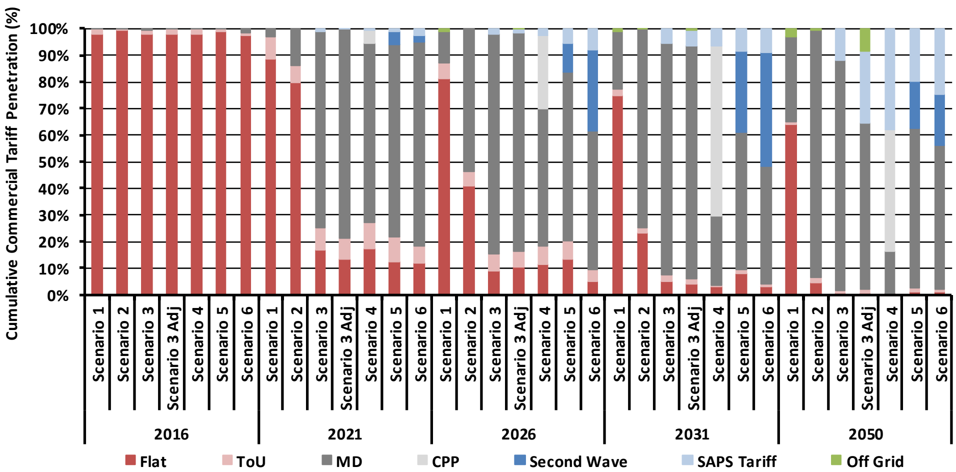


Figure 11 – Victorian Commercial Tariff Penetration

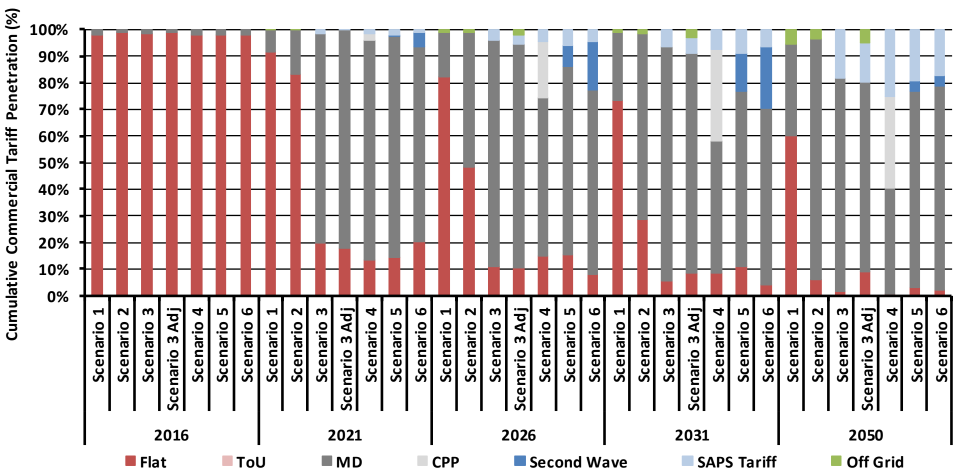


Figure 12 – South Australian Commercial Tariff Penetration

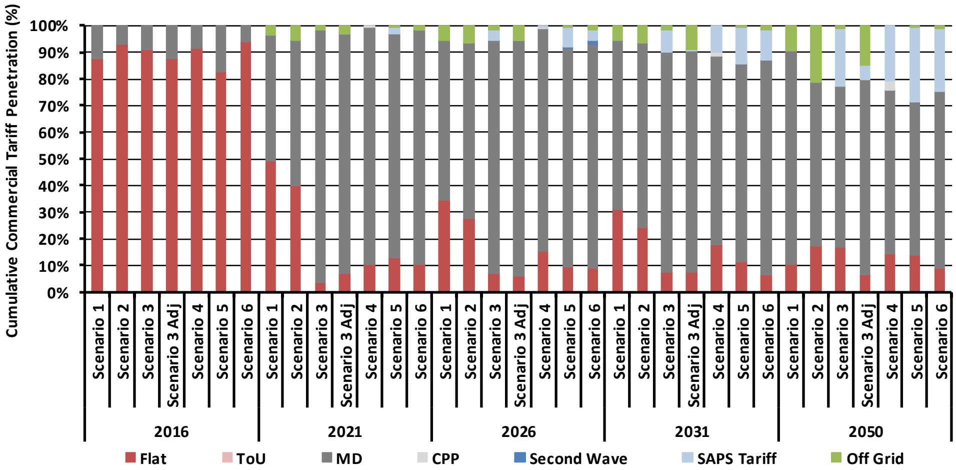


Figure 13 – Tasmanian Commercial Tariff Penetration

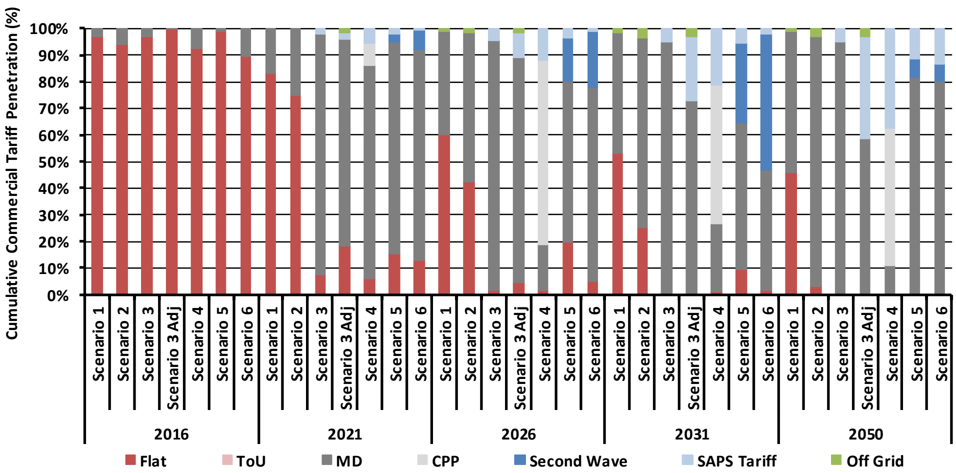
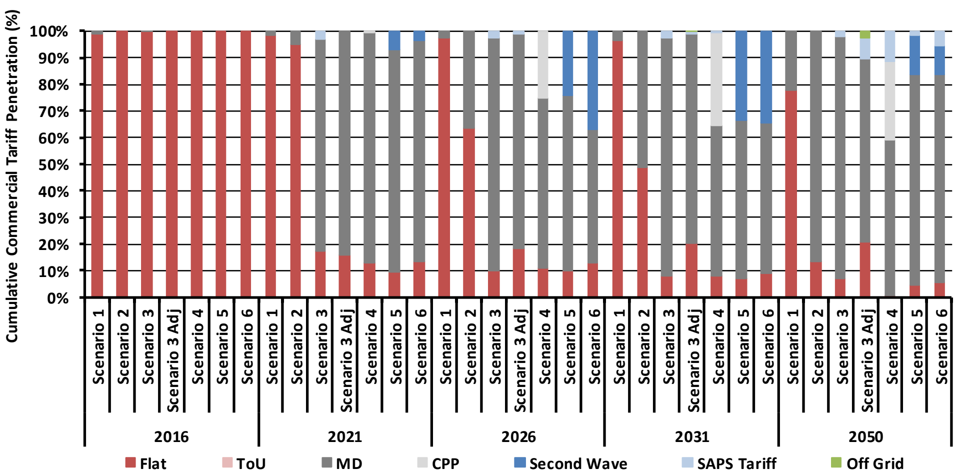


Figure 14 – West Australian Commercial Tariff Penetration



4.3 Total DER Capacity

Figure 15 – Queensland Total DER Capacity

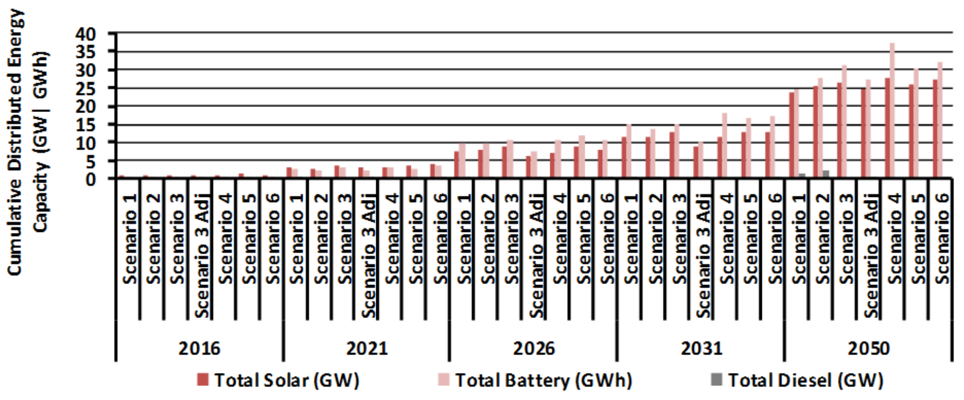


Figure 16 – NSW Total DER Capacity

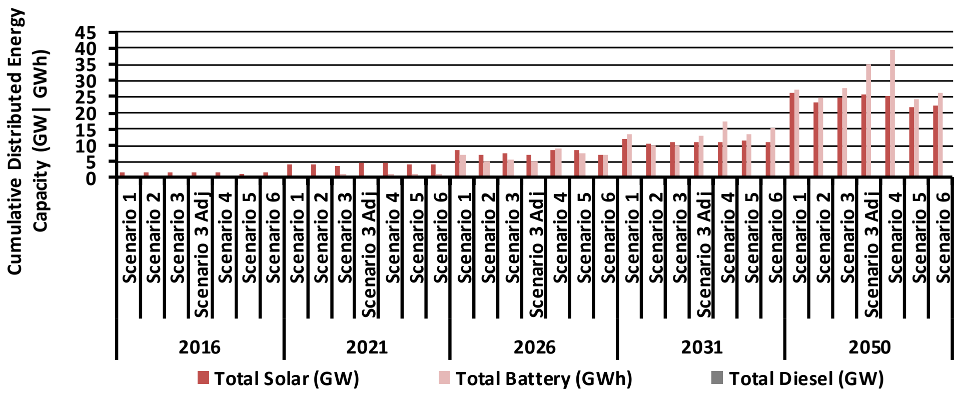


Figure 17 – Victorian Total DER Capacity

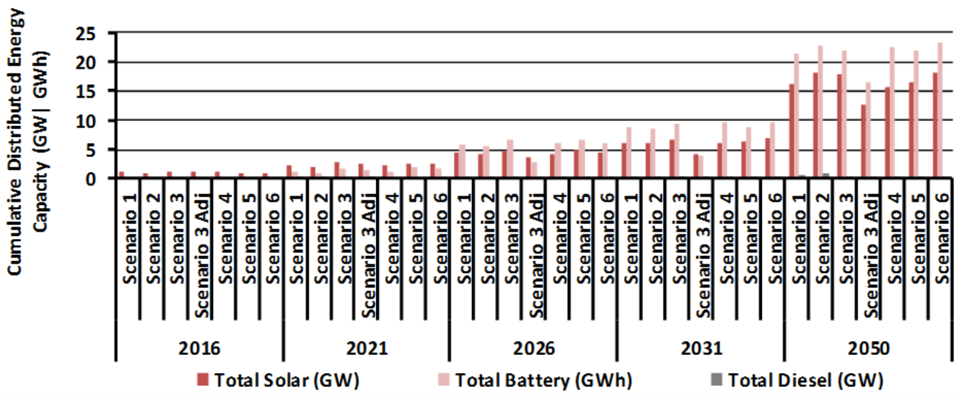


Figure 18 – South Australian Total DER Capacity

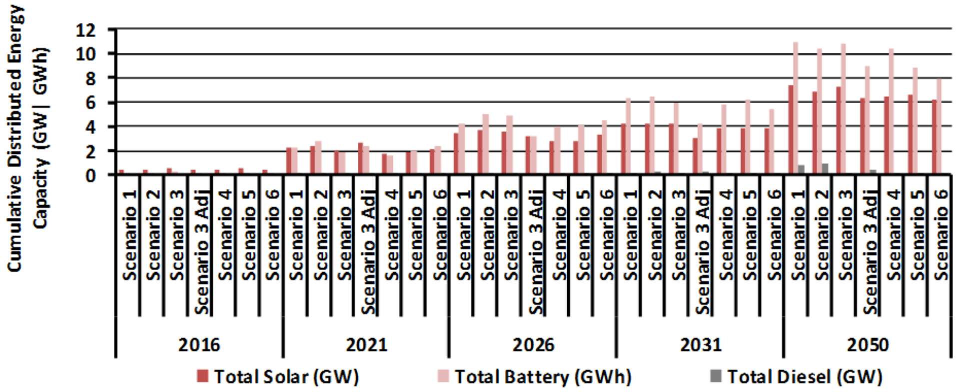


Figure 19 – Tasmanian Total DER Capacity

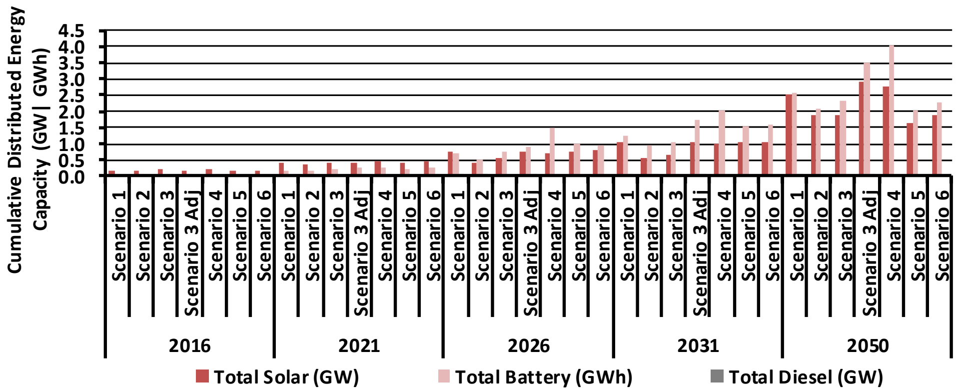
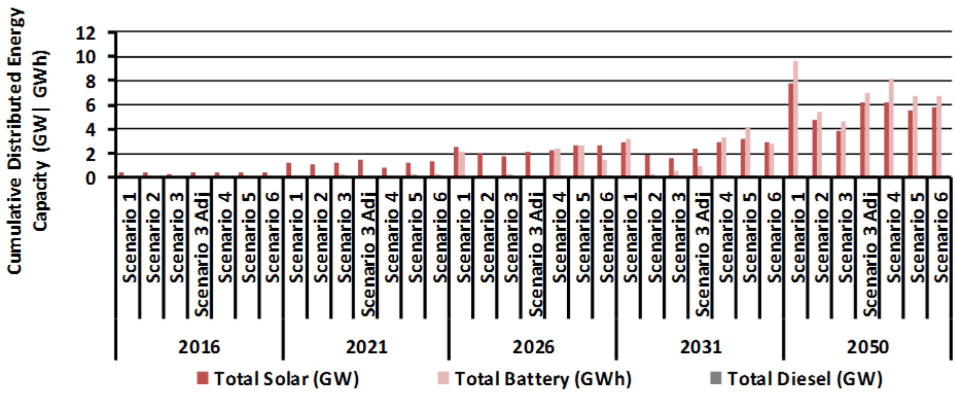


Figure 20 – West Australian Total DER Capacity



4.4 Total Peak Demand

Figure 21 – Queensland Total Peak Demand

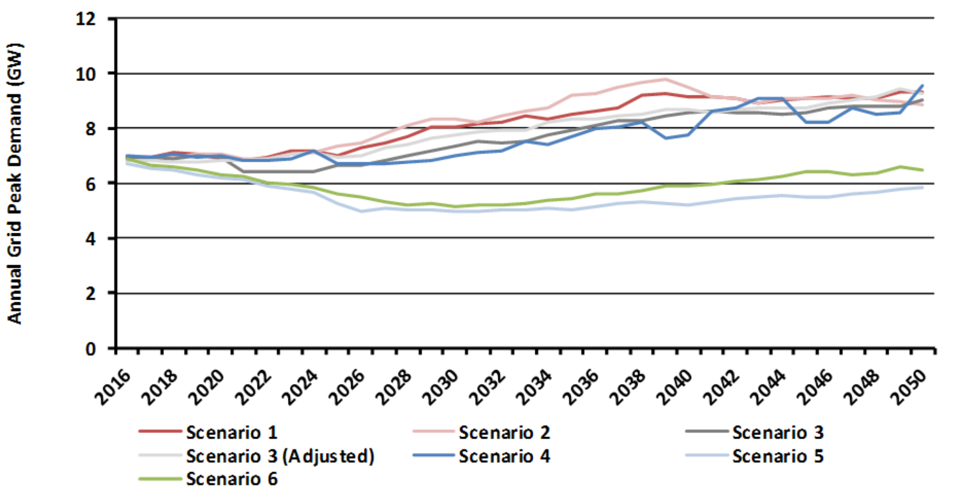


Figure 22 – NSW Total Peak Demand

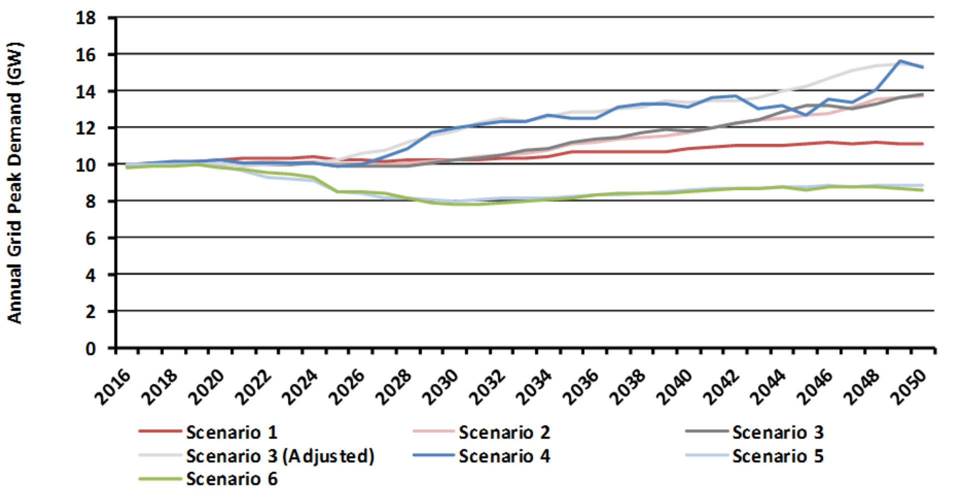


Figure 23 – Victorian Total Peak Demand

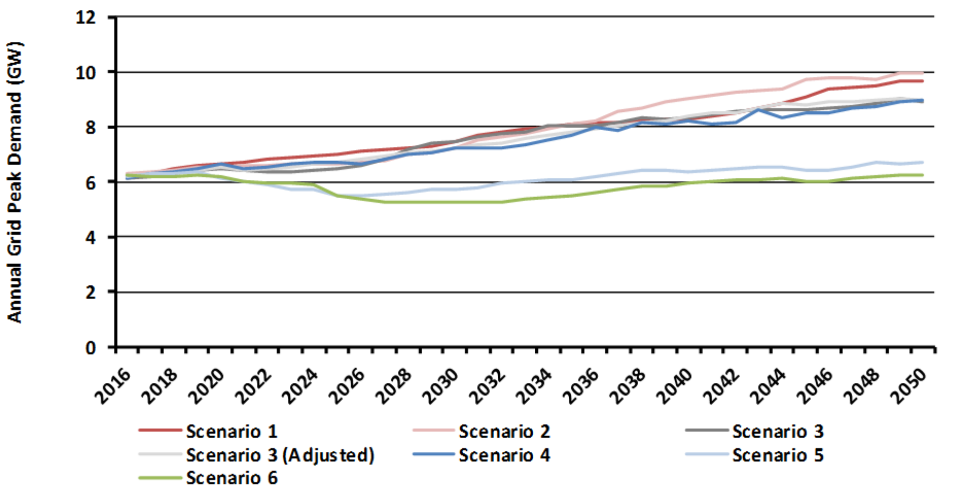


Figure 24 – South Australian Total Peak Demand

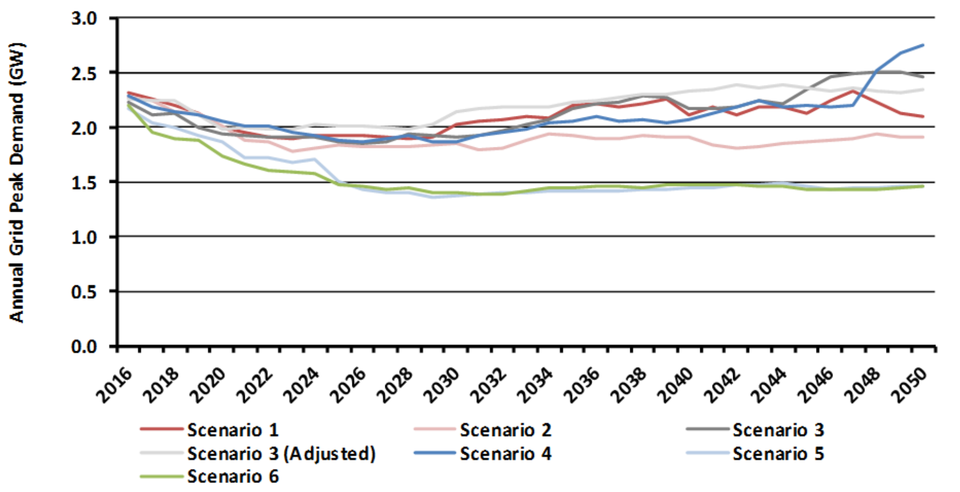


Figure 25 – Tasmanian Total Peak Demand

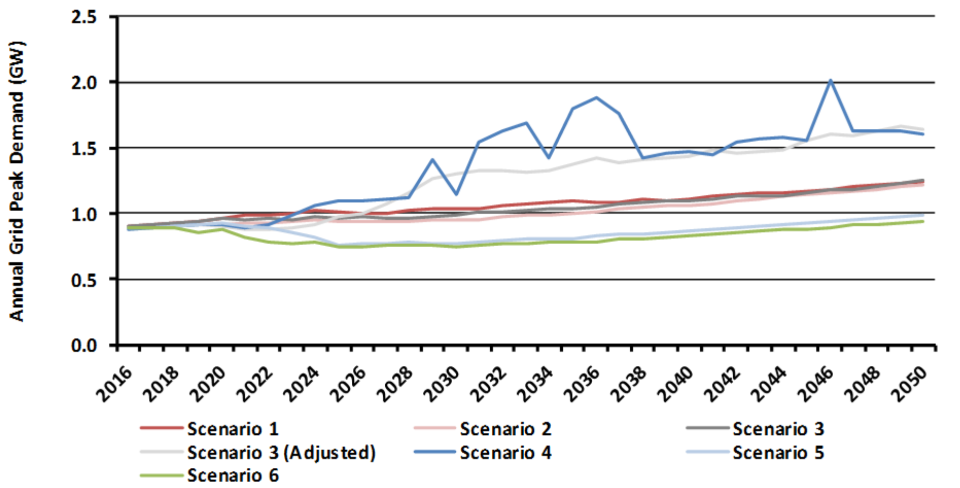
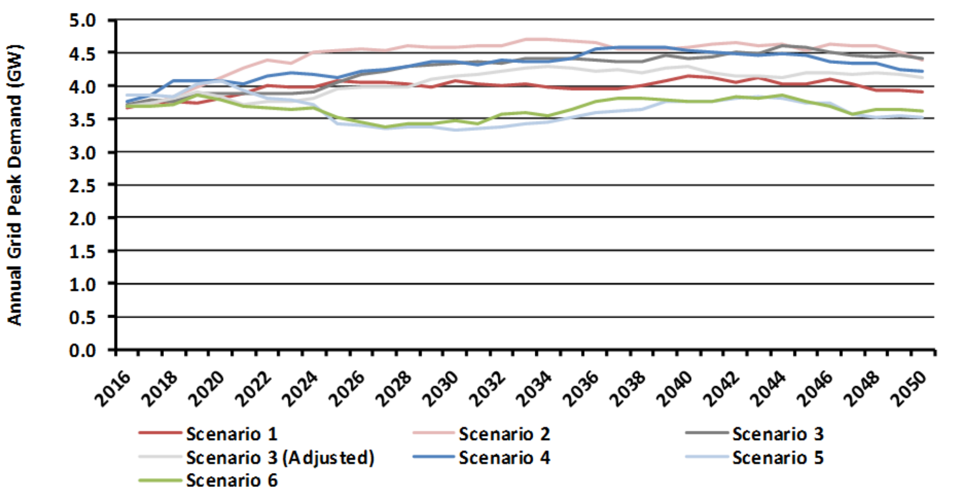


Figure 26 – West Australian Total Peak Demand



4.5 Economic Benefits 2026

Figure 27 – Queensland Economic Benefits (2026)

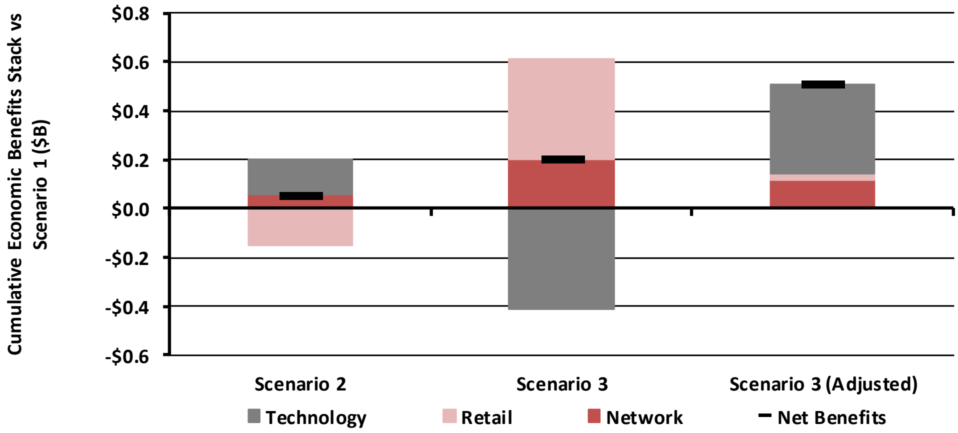


Figure 28 – NSW Economic Benefits (2026)

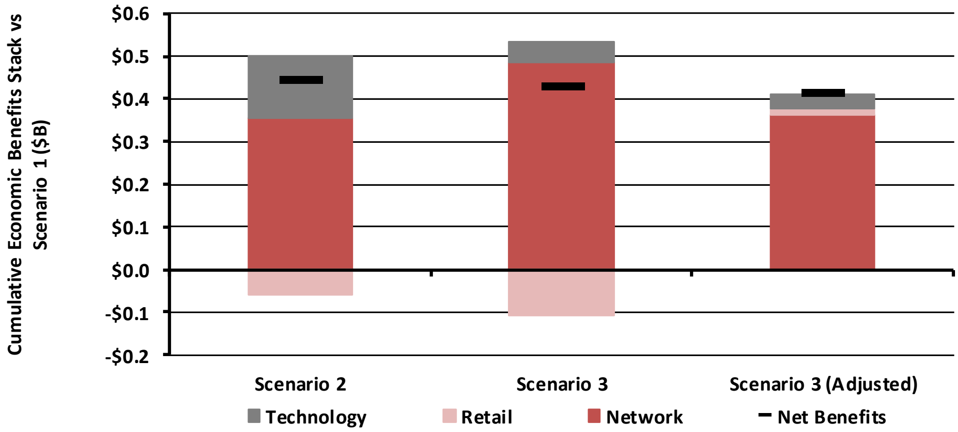


Figure 29 – Victorian Economic Benefits (2026)

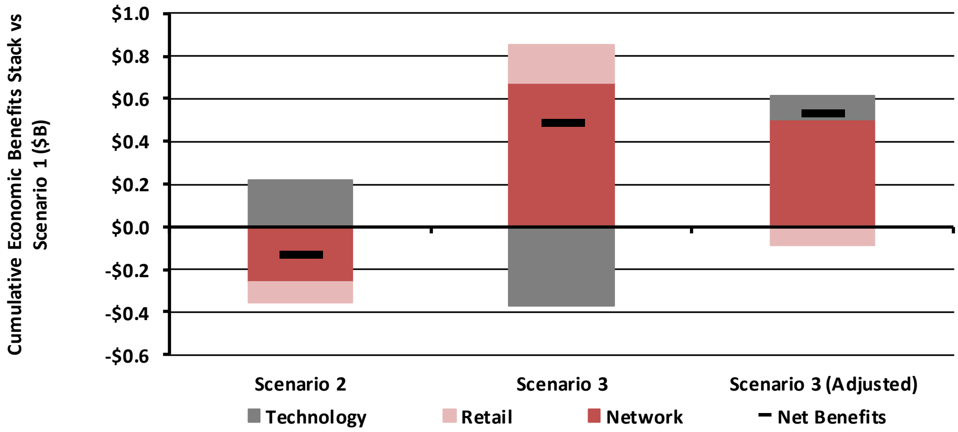


Figure 30 – South Australian Economic Benefits (2026)

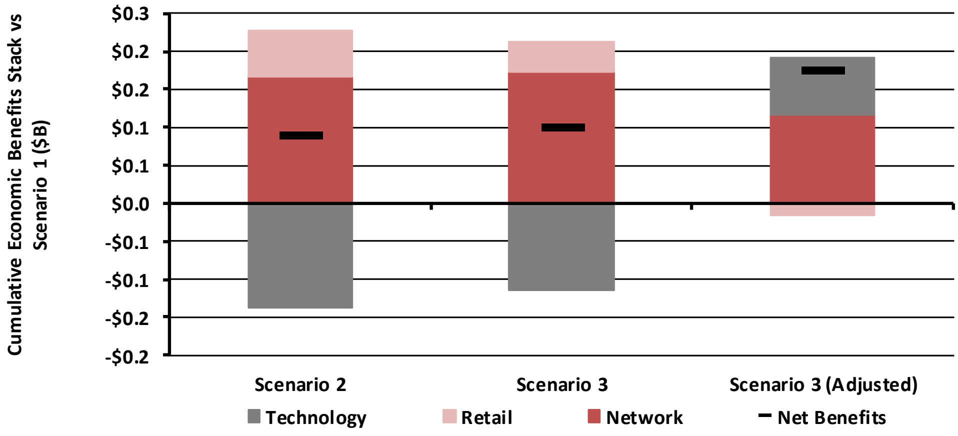


Figure 31 – Tasmanian Economic Benefits (2026)

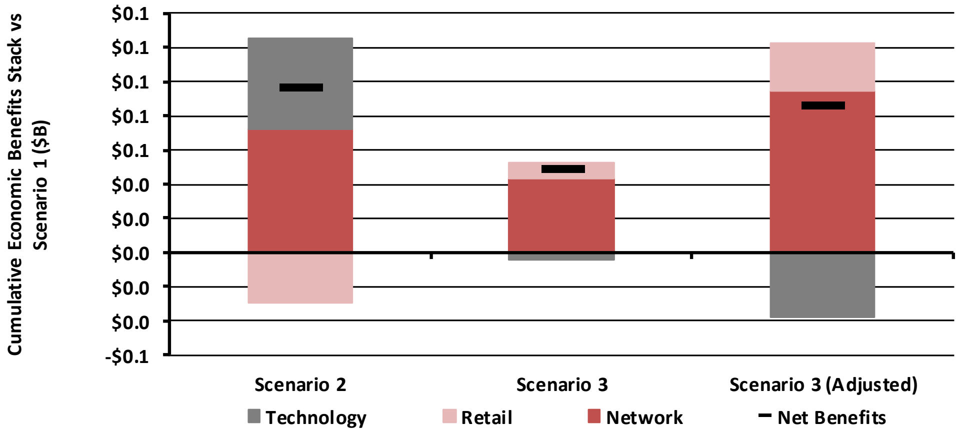
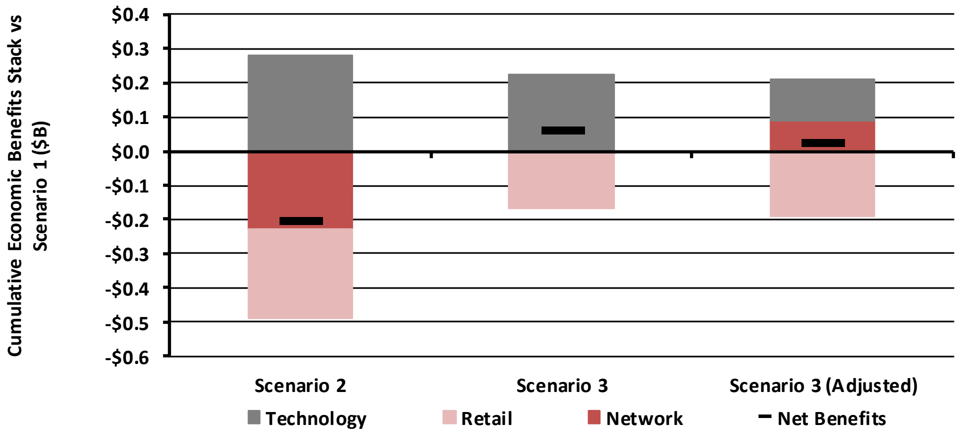


Figure 32 – West Australian Economic Benefits (2026)



4.6 Economic Benefits 2050

Figure 33 – Queensland Economic Benefits (2050)

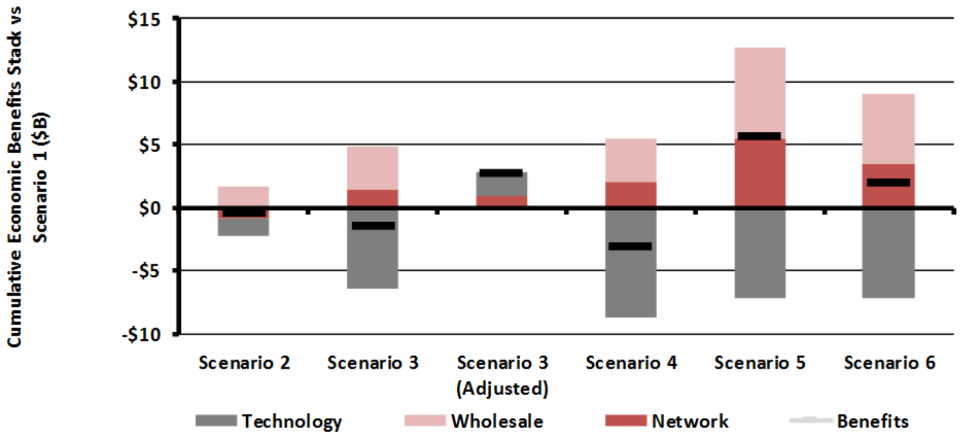


Figure 34 – NSW Economic Benefits (2050)

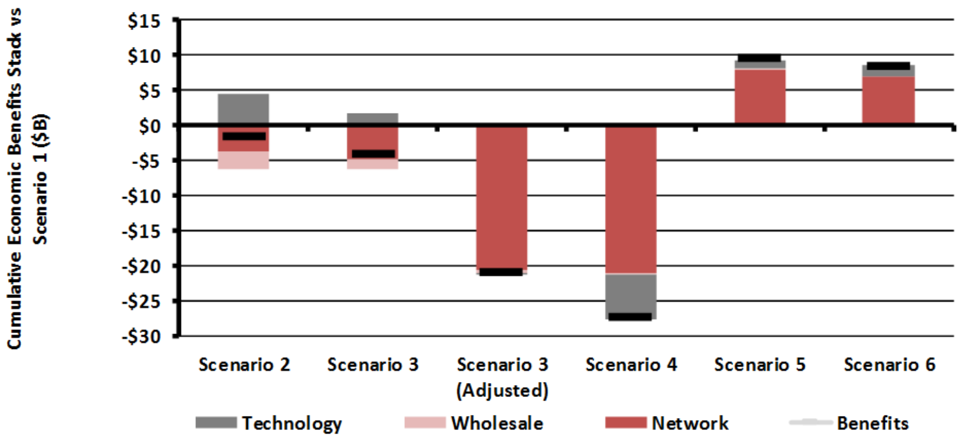


Figure 35 – Victorian Economic Benefits (2050)

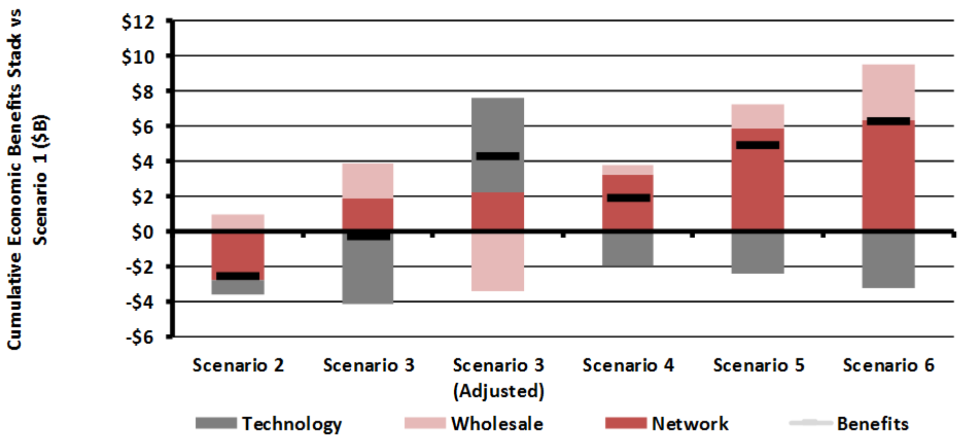


Figure 36 – South Australia Economic Benefits (2050)

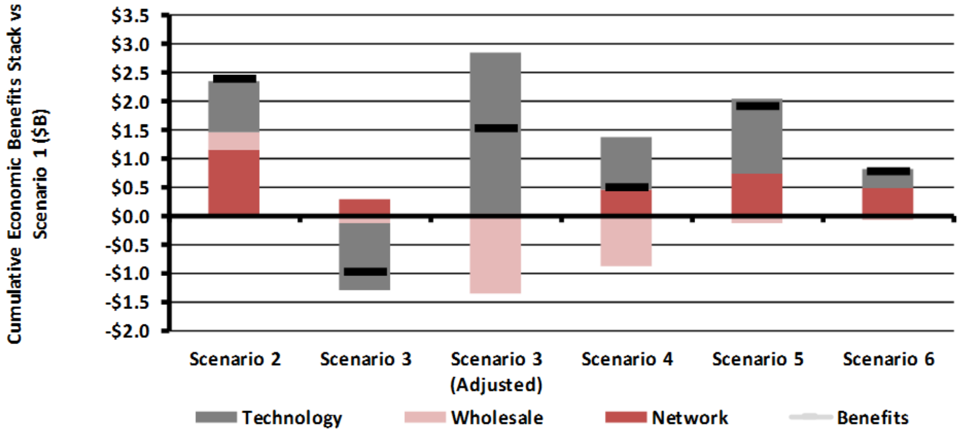


Figure 37 – Tasmania Economic Benefits (2050)

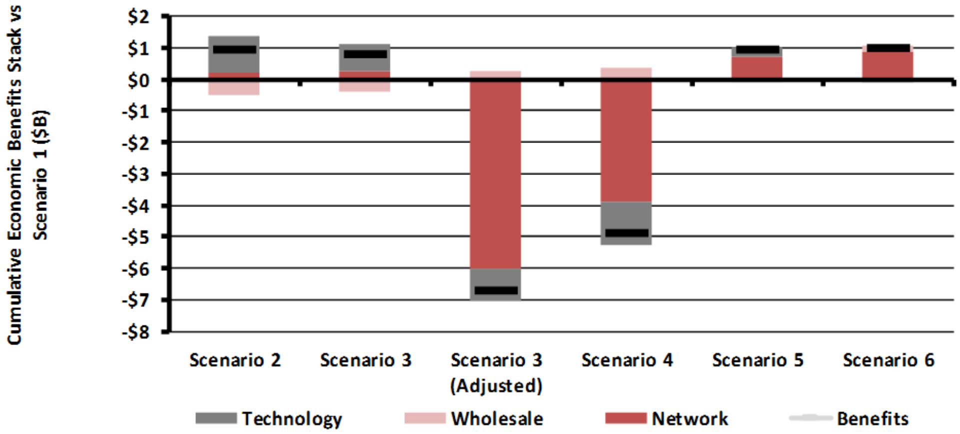
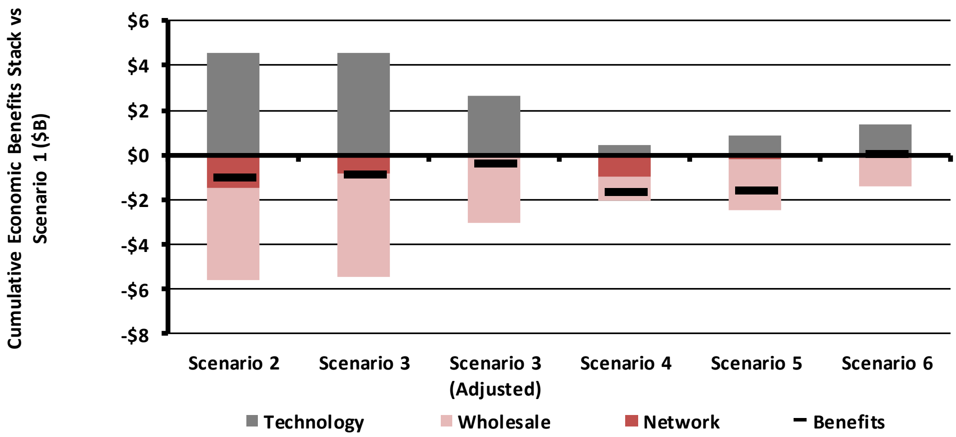


Figure 38 – West Australian Economic Benefits (2050)



4.7 Cross Subsidy 2026

Figure 39 – Queensland Cross Subsidy (2026)

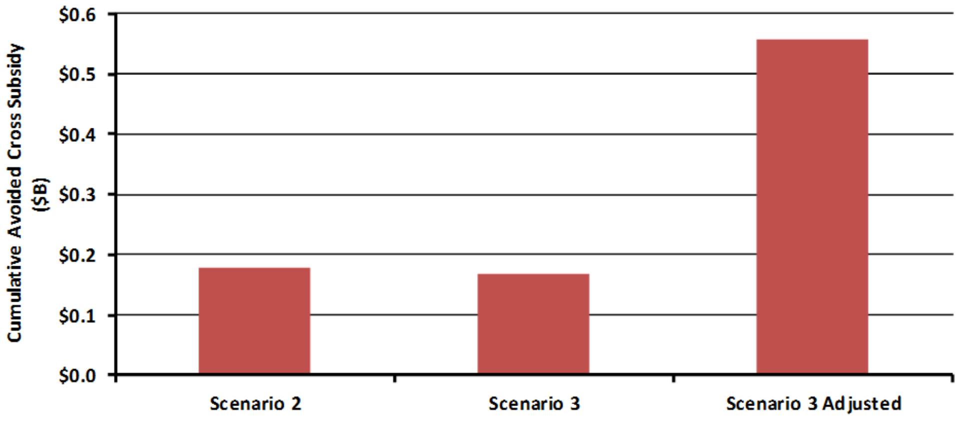


Figure 40 – NSW Cross Subsidy (2026)

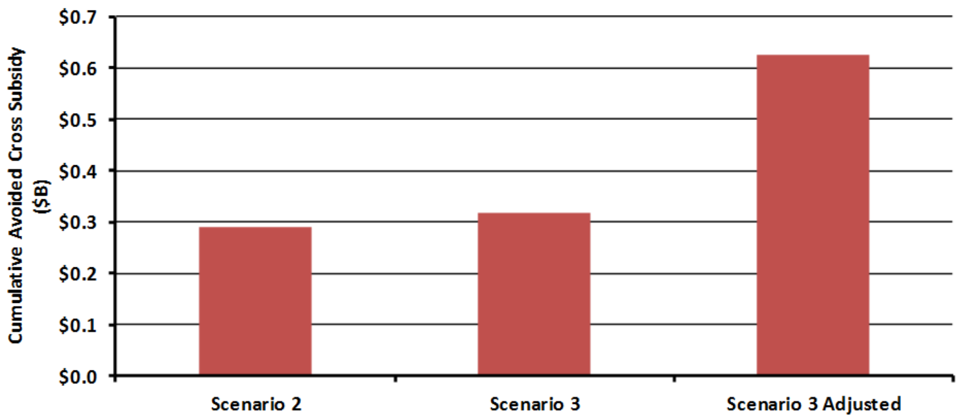


Figure 41 – Victorian Cross Subsidy (2026)

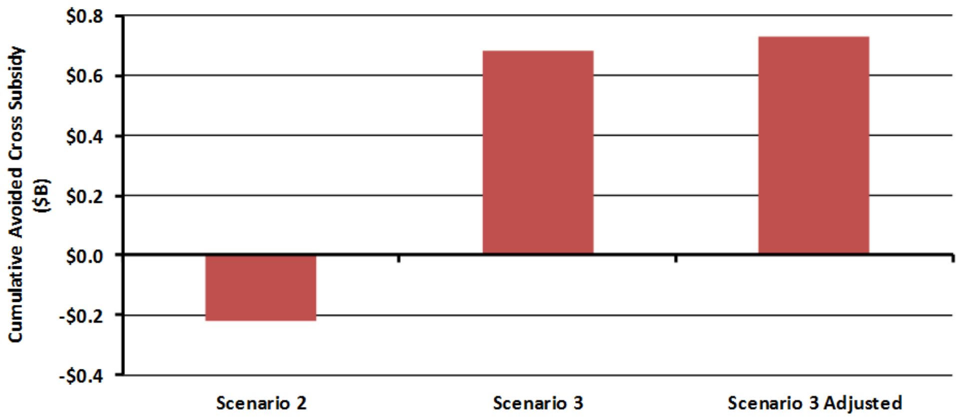


Figure 42 – South Australian Cross Subsidy (2026)

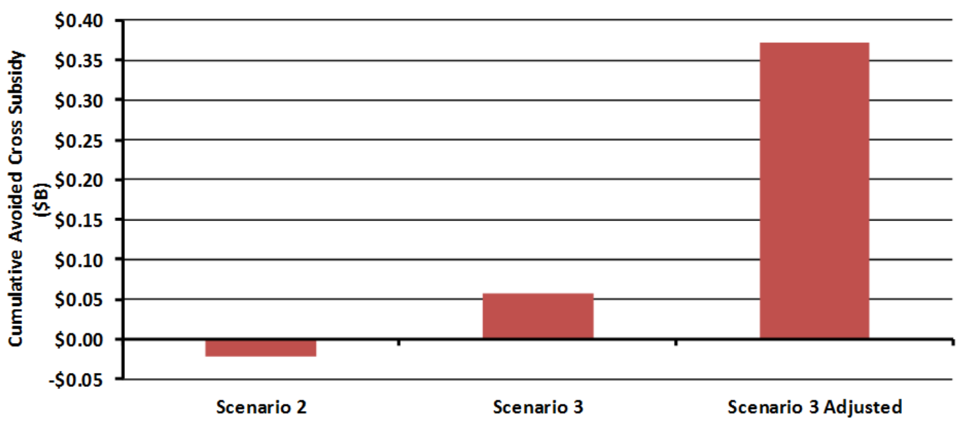


Figure 43 – Tasmania Cross Subsidy (2026)

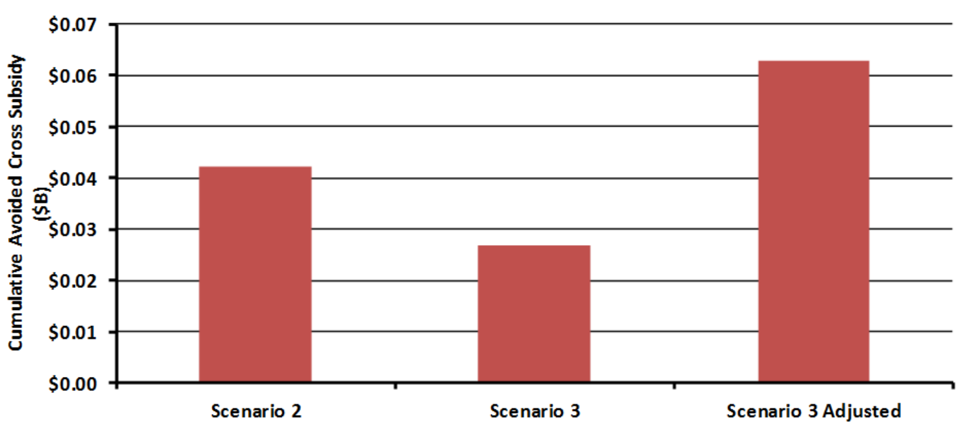
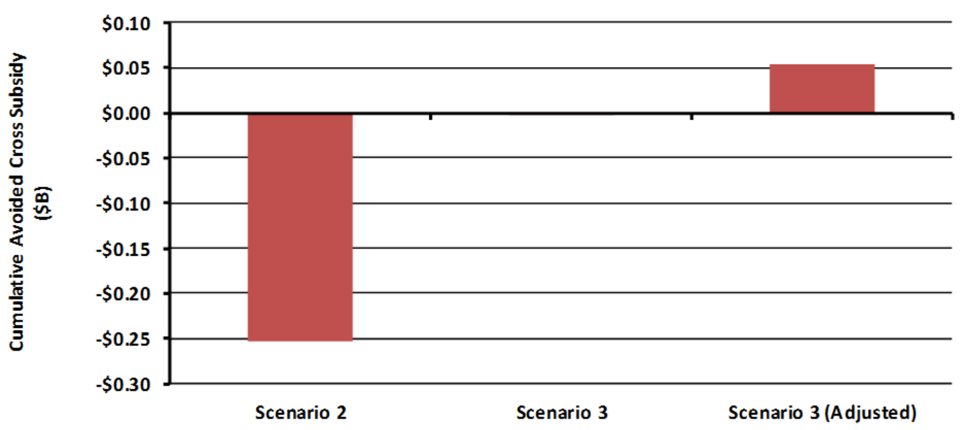


Figure 44 – West Australian Cross Subsidy (2026)



4.8 Cross Subsidy 2050

Figure 45 – Queensland Cross Subsidy (2050)

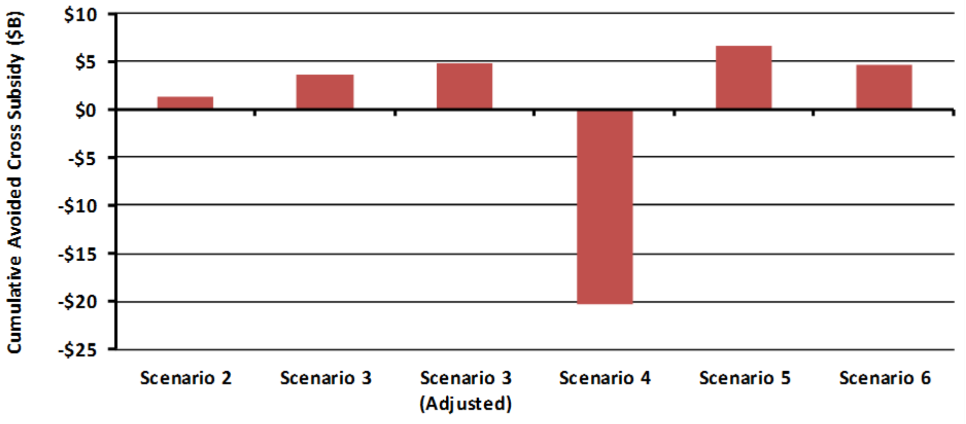


Figure 46 – NSW Cross Subsidy (2050)

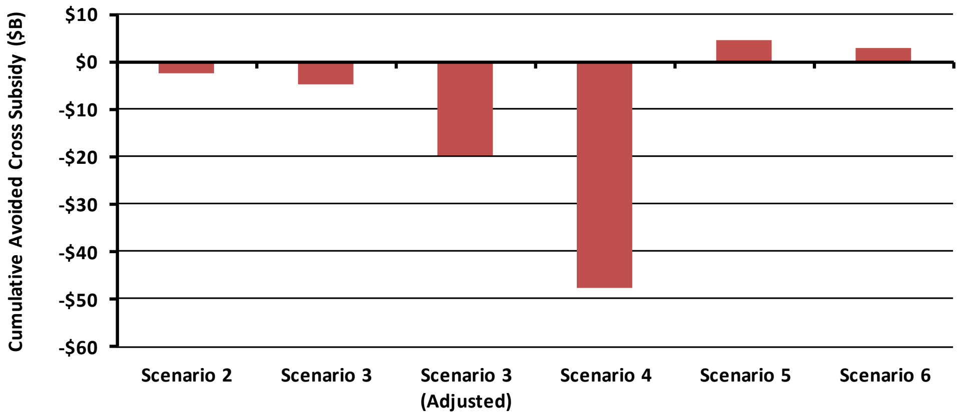


Figure 47 – Victorian Cross Subsidy (2050)

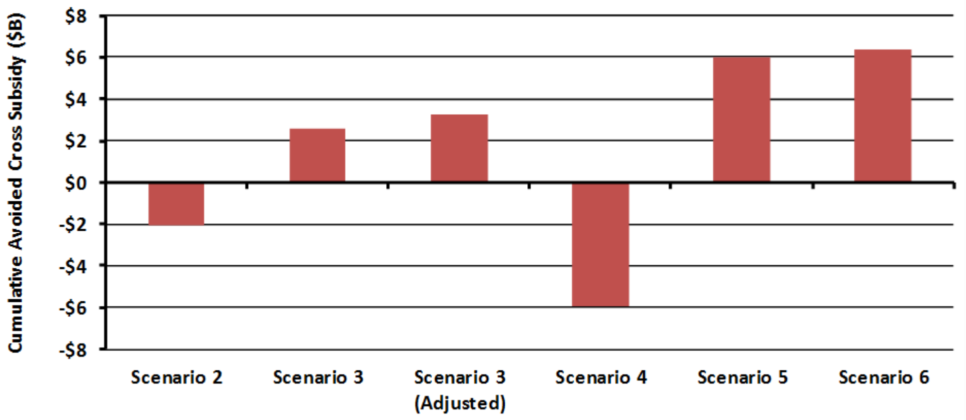


Figure 48 – South Australian Cross Subsidy (2050)

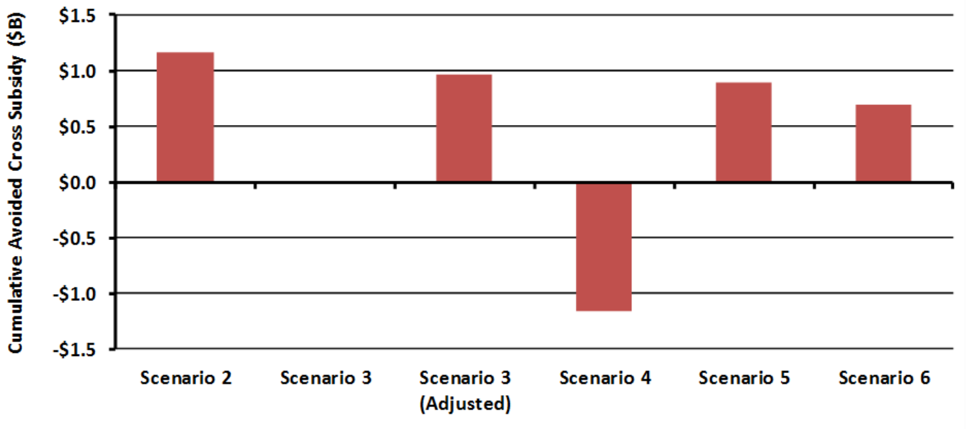


Figure 49 – Tasmanian Cross Subsidy (2050)

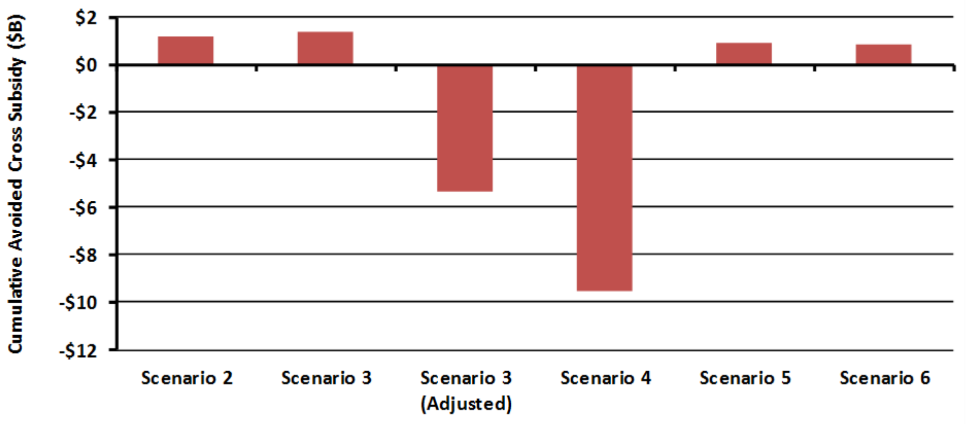


Figure 50 – West Australian Cross Subsidy (2050)