ENERGEIA

Network Transformation Roadmap: Work Package 5 – Pricing and Behavioural Enablers

Network Pricing and Incentives Reform

Prepared by ENERGEIA for the Energy Networks Association

October 2016

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Table of Contents

Table of Tables

Table of Figures

Executive Summary

The technological landscape upon which our energy system is founded is shifting from a centralised system, serving relatively passive consumers, to a system increasingly dominated by decentralised energy resources and active customers with heterogeneous attitudes towards technology. Accordingly, there is an increasing requirement for better cost reflectivity in the way in which energy is transacted throughout the energy supply chain.

Technological disruption to the traditional supply chain can provide the community immense benefits through both integration with and competition against traditional energy services. At the same time, the energy transactions underpinning technological investment and operation need to be cost reflective to allow the timely and efficient integration of the decentralised and centralised systems.

Without such cost reflectivity, there is an increasing risk of existing pricing and incentives giving rise to two poorly integrated, parallel power system infrastructures. Stronger integration should ideally support fair value exchange between parties, make available new opportunities to customers and reduce systems costs as a whole. It should also limit the degree of inequitable distribution of bill outcomes between those with the knowledge to participate and prosper and those without.

While there is broad stakeholder consensus for the need for change, there are a range of different perspectives as to what form the change should take, and over what time frame it should be implemented.

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.

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

Objective of this Report

The overall objective of this report is to assist ENA/CSIRO identify potential roadmap measures related to integrated electricity pricing and incentive reforms which promote key principles of ***efficiency, equity, simplicity, stability, viability*** and ***minimised cross subsidies*** aligned to the balanced score card adopted for the purposes of the ENTR.

Specifically, this report seeks to:

1. Quantify the impact of "First Wave" network tariff and meter migration reform options on the overall efficiency of Australia's electricity system.

   For the purposes of this report, First Wave reforms refer to the range of tariff structures and tariff assignment mechanisms currently being contemplated by distribution network service providers (DNSPs) including maximum demand tariffs and the range of triggers for tariff assignment.

2. Quantify the potential benefits of "Second Wave" network tariff reform and incentive options encompassing dynamic and locational price signals and the concepts of transactional energy.

   For the purposes of this report, "Second Wave" network tariff reform and incentive options refer to the range of tariffs and other forms of incentives and procurement methods including contracting and transactional platforms which provide dynamic price signals.

Approach

Energeia has adopted its Distributed Energy Resource (DER) simulation platform to model how various scenarios of network tariff and incentive reform will influence outcomes in the electricity system. Energeia's DER simulation platform has been used previously in other contexts for a range of different stakeholders to provide insights into the linkages between tariff reform and electricity system response.

For the purposes of this study, the modelling seeks to identify how different network tariff and alternative incentive structures and assignment mechanisms:

- Affect customer decisions with respect to the uptake, sizing and operation of distributed energy resource technology
- Influence network expenditure patterns
- Make use of investment in smart meter infrastructure
- Impact network price rises and consumer bills
- Reduce the extent of cross subsidisation between passive customers and customers who are engaged in DER technology and demand management more broadly.
- 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 interests of consumers

A set of seven scenarios were modelled as described below.

<u>First Wave Scenarios</u>

- **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 and any customer who adopts DER either 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 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.

<u>Second Wave Scenarios</u>

- **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.

Importantly, it should be noted that changes to tariffs or tariff structures in different scenarios are revenue neutral for network businesses in the short term – the network recovers the same amount of revenue and is neither better nor worse off as a result of that change. In the medium to long term, changes to tariff structures in different scenarios will impact network investment – lower investment results in lower revenue for networks to recover from customers which in most circumstances increases the overall economic benefit in our scenarios tested.

Further, for the purposes of the modelling and understanding optimal customer responses, network tariffs are modelled as if retailers passed them through exactly. However in reality this approach is not necessarily required in all scenarios to achieve the outcomes. We already see, and would expect to see more, significant innovation in the retail space in terms of how they present even base case tariffs to customers as the market evolves.

To the extent that retailers seek to "bundle" peak and residual signals in the customer facing tariff, the need for second wave incentives to allow better optimisation of the grid and DER through second wave incentives becomes even more important.

Findings

Benefits of First Wave Network Tariff Reform

The results of the modelling demonstrate clear economic benefits in terms of overall efficiency and equity through shifting to more cost reflective network tariffs as proposed by distribution networks under First Wave tariff reform in the medium term. These benefits increase based on how quickly customers transition to cost reflective tariffs in each scenario.

Under all scenarios, the modelling assumes that for the current regulatory period to 2021, the DNSP tariff structures and tariff assignment mechanisms, as proposed in their Tariff Structure Statements, are locked in. That is, over the period to 2021, customers are gradually transitioned to First Wave cost reflective tariffs under a largely opt-in framework.

Then, from 2021, the scenarios diverge in terms of the tariff assignment mechanism. Those scenarios which adopt an opt-out mechanism from 2021 (either partially as a default tariff for new and replacement meter customers in Scenario 2, or through a mass transition of all existing customers in Scenario 3) out-perform the base case.

An opt-out tariff assignment mechanism performs better because it limits inefficient over-investment in solar PV which, under volume based tariffs, creates cross subsidies. In addition, the opt-out approach also ensures that both high cost to serve *and* low cost to serve customers are transitioned to the more cost reflective tariff and avoids the self-selection that otherwise occurs under opt-in approaches.

Figure 1 and Figure 2 show how these benefits play out in terms of average customer bills for residential and commercial customers respectively to 2026. The bills are shown for each component including:

- The average network tariff component
- The average retail tariff component (including wholesale generation and retail costs, but excluding the impact of the carbon price)
- The contribution of the carbon price to the average retail bill
- The average cost of DER technology

It should be noted that the average cost of DER technology does not appear on the consumer's bill (unless financed by the retailer) but is included for completeness, representing the total consumer expenditure on electricity supply.

Figure 1 – Average Residential Bills to 2026

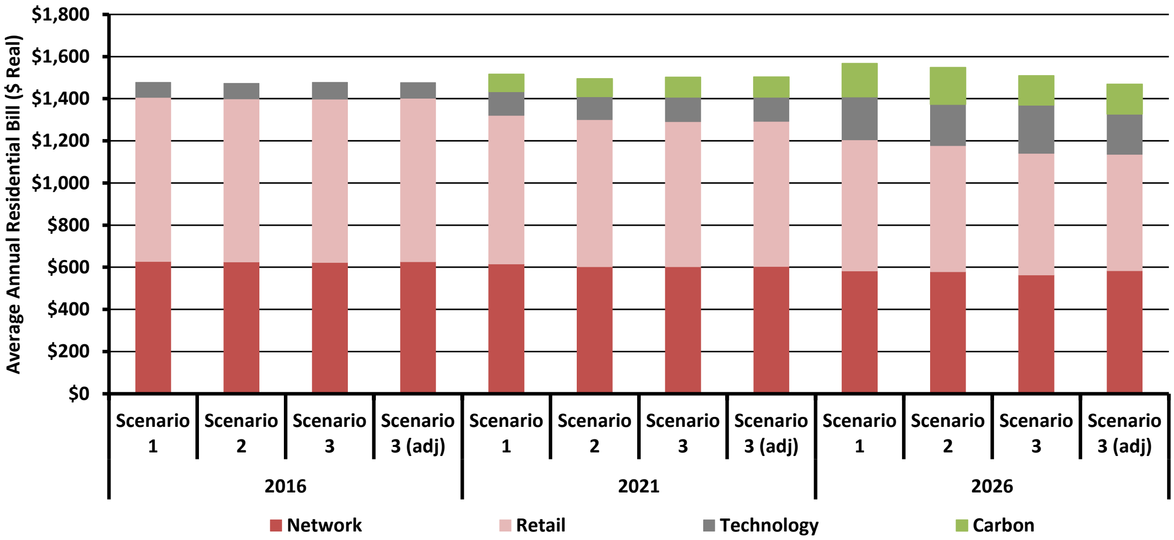
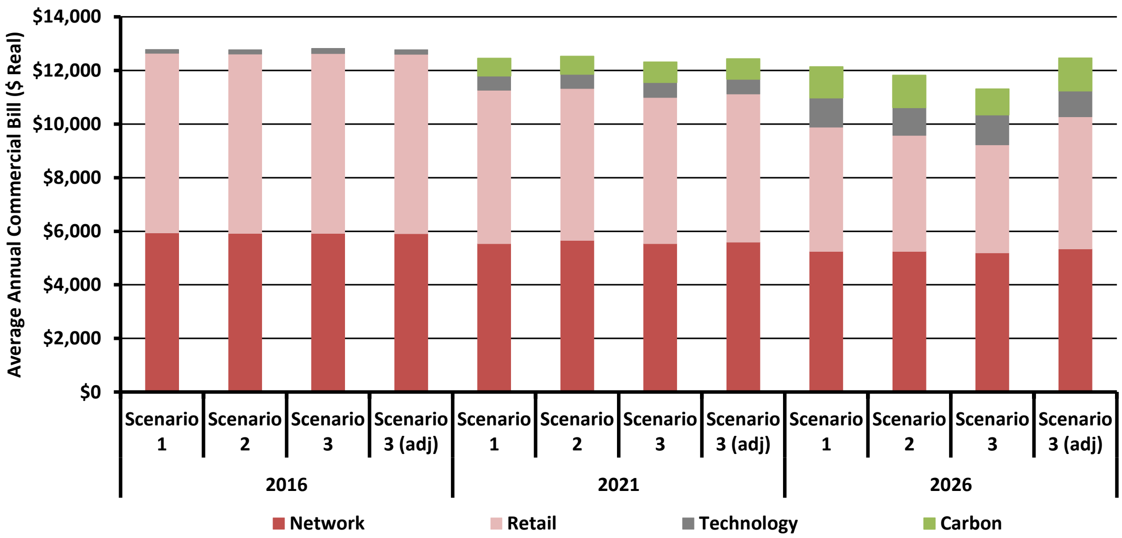


Figure 2 – Average Commercial Bills to 2026



It can be seen that the largest driver of bill increases is the impact of a carbon price. Average residential bills increase by between $113 and $ 129 per year (depending on scenario) and average commercial bills increase by between $1,059 and $1,213 over the period between 2016 and 2026 as a result of the carbon price.

Notwithstanding this increase, the opt-out mechanism under Scenario 3 is able to deliver the greatest medium term benefits over the period to 2026 in terms of:

- A modest reduction in total average ***residential*** bills of $8 per annum or 1% by 2026 in Scenario 3 (Adjusted) compared to 2016 levels as shown in Figure 1 (while all other scenarios show an increase)
- A material reduction in the network component of the average ***residential*** bill of $60 or 9.6% by 2026 in Scenario 3 compared to 2016 as shown in Figure 1
- A reduction in average ***commercial*** bills of $1,512 per annum or 12% by 2026 in Scenario 3 as shown in Figure 2
- A reduction in the network component of the average ***commercial*** bill of $723 per annum or 12.2% by 2026 in Scenario 3 (Adjusted) as shown in Figure 2.

At a system level (NEM), these bill benefits over the five year period between 2021 and 2026 translate into:

- Up to $1.8B in economic benefit as shown in Figure 3

- Reduced network investment of up to $1.4B as shown in Figure 3
- Up to $1.4B in reduced cross subsidies over the same period as shown in Figure 4.

Figure 3 – Economic Benefits of First Wave Tariff Reform to 2026 Compared to Scenario 1

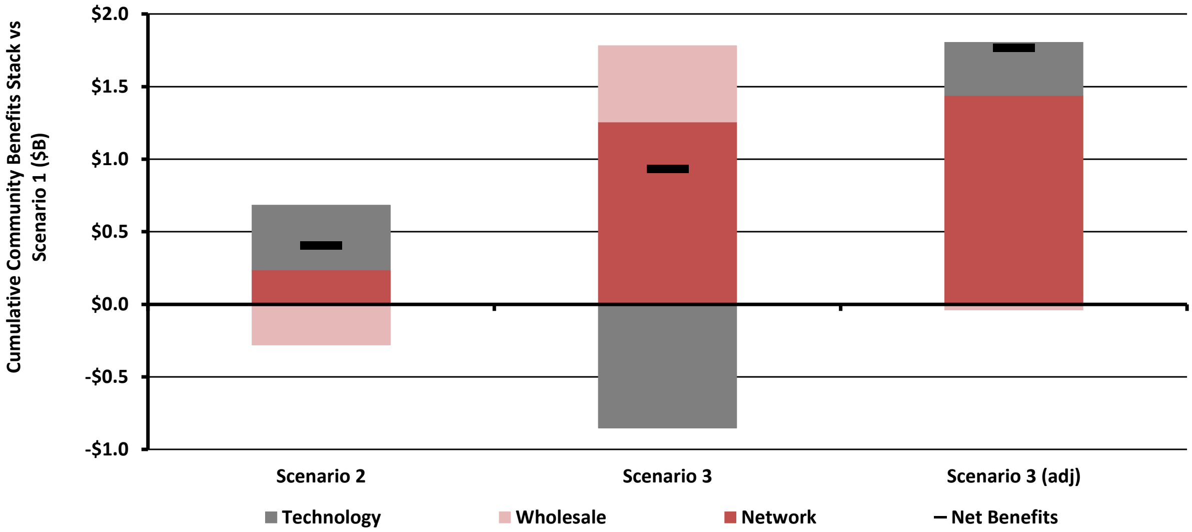
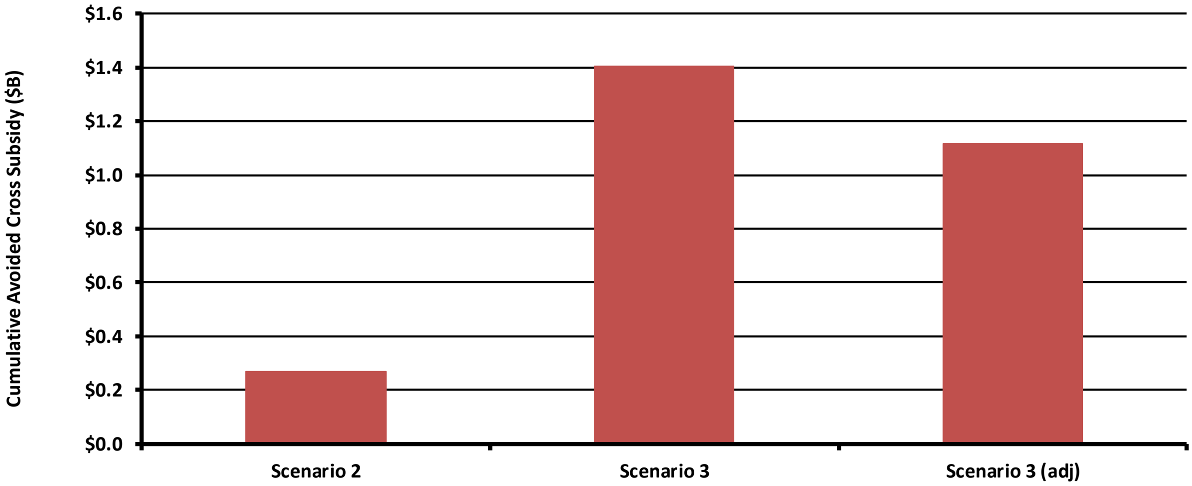


Figure 4 – Avoided Cross Subsidies to 2026 Compared to Scenario 1



It should be noted that even greater benefits could be expected should the opt-out policy be implemented prior to 2021[1] by avoiding the lock in of further cross subsidies. However, this is considered unlikely given that no network Draft Tariff Structure Statement has proposed such an opt-out mechanism.

Importantly, the aggregated net benefits shown in Figure 3 and 4 above can vary significantly between distribution network service providers (DNSPs), and it is therefore important that actual tariff reforms be tailored to each DNSP's specific situation.

__Refinement of Current First Wave Tariff Reform__

Despite the near term effectiveness of First Wave tariff reform, from 2026 the benefits of the maximum demand (MD) tariffs as modelled, start to erode particularly in an environment of falling battery costs. Left unamended, the current design of most network service providers' maximum demand tariffs would become vulnerable to a high degree of penetration from distributed battery storage over time.

[1] In its modelling for ENA on the benefits of network tariff reform in 2014, Energeia assumed that opt-out was adopted from 2015, thereby delivering earlier benefits that are not captured here.

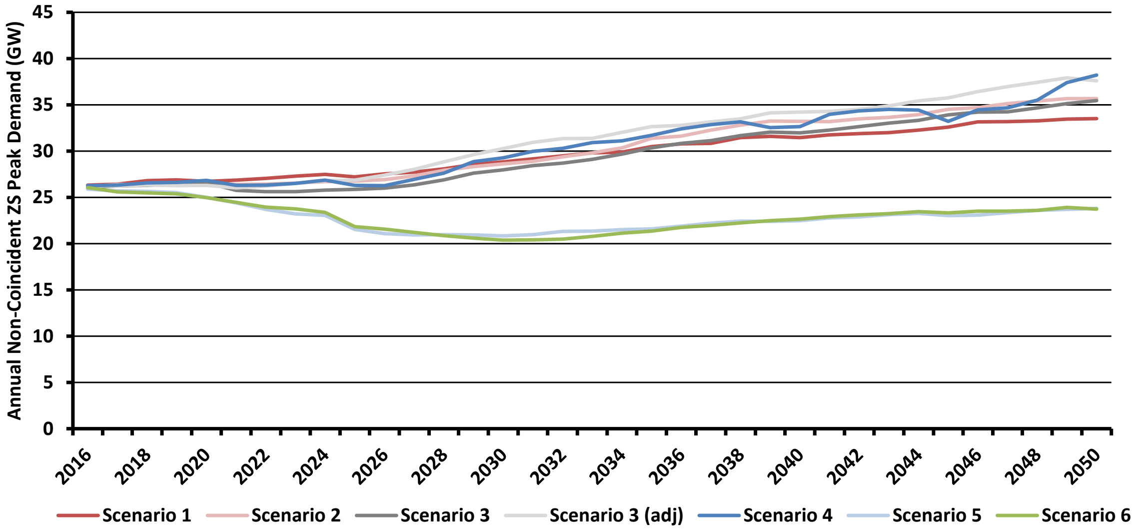
Based on the tariffs modelled, a critical mass of battery storage begins to reveal a number of issues:

- The discharge of batteries during the peak period focuses on customer's own peak, limiting effectiveness in providing locational network benefits[2].
- The charging of batteries in the off-peak period is uncontrolled, and therefore commences as soon as the peak period is over, creating a new peak and effectively *increasing* network costs

Energeia's modelling shows that changes will be required to current maximum demand tariff design to be resilient to widespread storage adoption. Without further refinement, the current breed of tariffs could ultimately lead to unsustainable *storage* cross subsidies, whereby storage customers offset network revenue without delivering the same level of network benefits, increasing costs for all consumers.

The long-term effect of storage and solar adoption is shown in Figure 5 below in terms of the average increase in the network peak demand.

Figure 5 – Non-Coincident ZS Peak Demand



While the maximum demand tariffs as proposed are effective in incentivising efficient investment in solar PV to 2026 compared to current volume based tariffs, their current structure makes them less effective in incentivising efficient investment in battery storage. This means that from 2026, the modelling shows that the benefits achieved by a faster adoption of the initial maximum demand tariffs begin to erode.

Energeia does not suggest that this is a sign to move away from cost reflectivity in tariff design or assignment. In fact, our view is that the modelling reinforces a need to increase more cost reflectivity. In other words, as technology becomes cheaper and smarter over the medium term, tariff design needs to be more sophisticated to address arbitrage opportunities from less efficient price signals.

There are many possible refinements to maximum demand based tariffs which can reduce vulnerability to exploitation by battery storage (when it emerges) as well as unintended consequences. These include:

a. Reforming the peak charging mechanism so that it is more effective at reducing network peak demand. For example, applying the peak charge across a number of peaks (e.g. the average top four mechanism proposed by Ergon Energy[3]) or adopting an average demand charge across the peak period. Both approaches improve alignment between the peak charging mechanism and the actual network peak, and therefore customer and network benefits from investing in DER.

[2] This weakness has been previously highlighted by others (e.g Davies and Passey, See Section 2)

[3] Note that such an approach has been suggested as worthy of further investigation in the AER's review of SA Power Networks' draft Tariff Structure Statement

b. Reducing the potential for network bypass by allocating a reduced proportion of the non-peak charge component away from volume based charges in order to reduce cross subsidies leading to over-investment and higher economic costs overall.

c. Incorporating mechanisms that increase diversity in battery storage charging outside of the peak period to avoid the creation of new network peaks.

There are also likely to be other incentive mechanisms outside of tariffs which can be used to increase diversity in battery charging such as network controlled charging and/or by mandating timer controlled charging through connection agreements.

The Need for Second Wave Reform

Whilst there are certainly mechanisms to improve the effectiveness of first wave tariff reform, what is clear is that at some point, and likely well in advance of 2030, there is a strong economic benefit in moving to more sophisticated tariffs which take into account the time (are dynamic) and locational values. Such incentives are directly aligned with the locational and temporally specific costs and/or savings their net load imparts on the electricity system.

Figure 6 and Figure 7 show how Second Wave benefits play out in terms of average customer bills for each bill component for the average residential and commercial customer respectively to 2050.

Figure 6 – Average Residential Bills to 2050

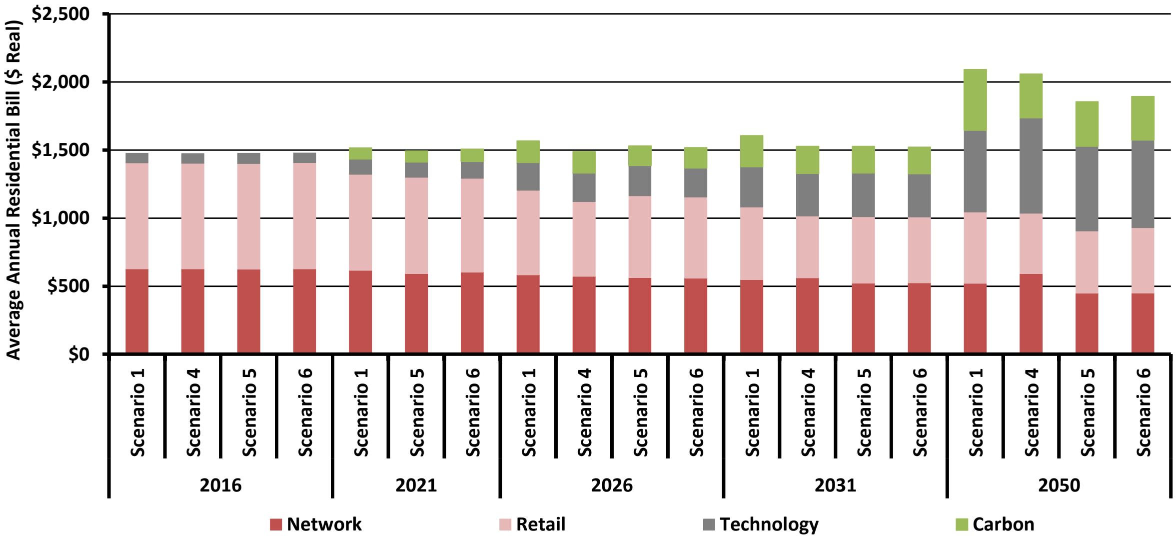
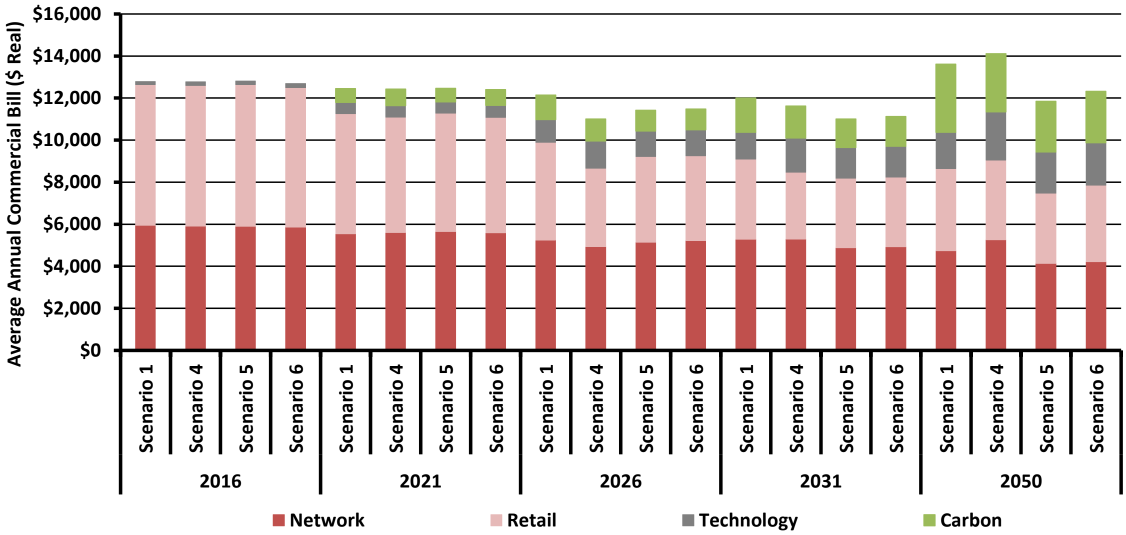


Figure 7 – Average Commercial Bills to 2050



It can be seen that while some savings in customers' bills can be made by the adoption of technology, the carbon price becomes an increasingly larger component of bills to 2050. By 2050 the carbon price contributes between $318 and $ 448 per year (depending on scenario) to the average residential bill and by between $3,292 and $2,654 per year to the average commercial bill.

Despite the carbon price impact, the modelling indicates that successful Second Wave tariff incentives (Scenarios 5 and 6), offering opt-in approaches from 2021 are able to:

- Deliver a reduction in the *network* component of the average ***residential*** bill of $175 per annum or 28% by 2050 in Scenario 6 compared to 2016 levels (as shown in Figure 6)
- Give rise to overall ***residential*** bill savings of $256 or 12% compared to the base case (as shown in Figure 6)
- Deliver a reduction in average ***commercial*** bills of $972 per annum or 8% by 2050 in Scenario 5 compared to 2016 levels (as shown in Figure 7)
- Deliver an even greater reduction in the *network* component of the average ***commercial*** bill of $1,766 per annum or 30% by 2050 compared to 2016 levels in Scenario 5 (as shown in Figure 7).

As a result of this, over the period between 2021 and 2050 compared to the base case, Second Wave reform can deliver:

- Total economic benefits of $16.7B (as shown in Figure 8)
- Reduced network investment of $16.2B (as shown in Figure 8)
- Avoided cross subsidies of $18.6B (as shown in Figure 9)

Figure 8 – Cumulative Economic Benefits to 2050 Compared to Scenario 1

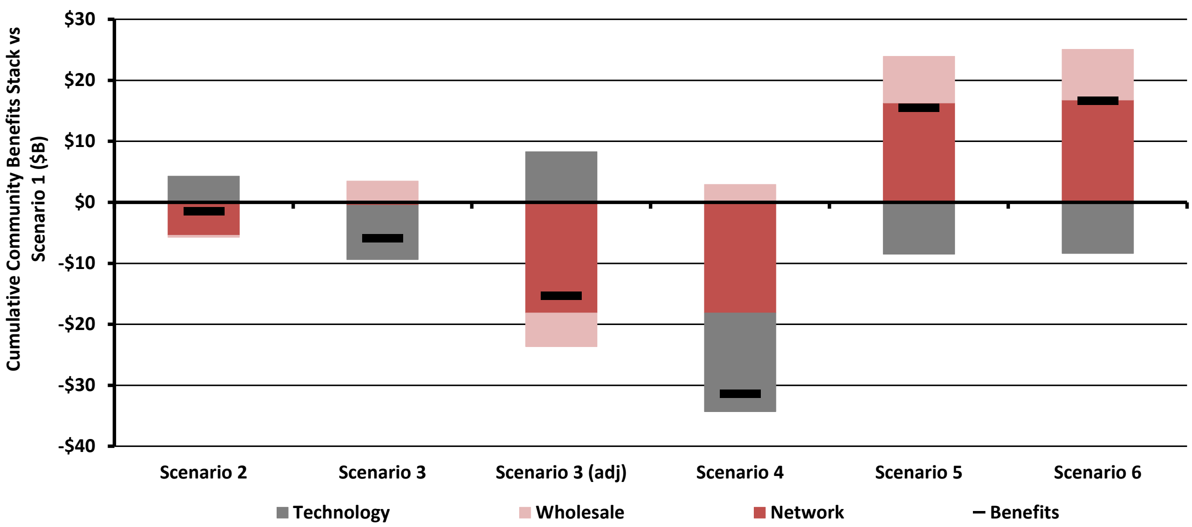
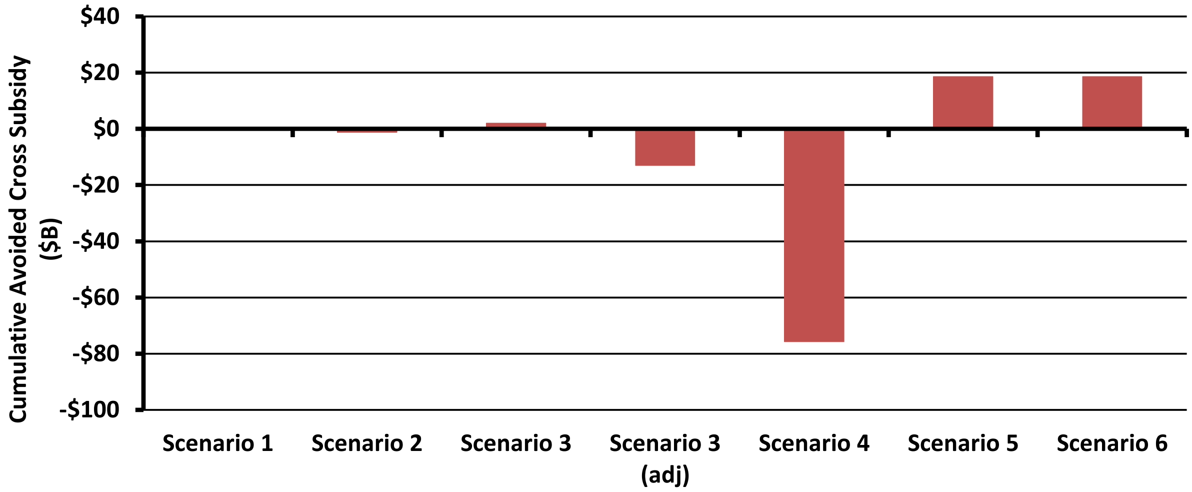


Figure 9 – Cumulative Cross Subsidies to 2050 Compared to Scenario1



Second wave incentives require careful design to incentivise locational value. For instance, Scenario 4 assessed a tariff option which was dynamic in time but only targeting a system peak (i.e. system level critical peak pricing). This indicates a potential for such system-wide approaches to fail to deliver material benefits on their own due to the location specific nature of distribution network peak demand and increase the risk of storage responses which increase uneconomic investment and higher customer cross-subsidies.

In addition to the economic and equitable benefits seen from moving to Scenario 5 and 6, these scenarios also provide the greatest value when considering new, customer facing aggregation platforms, and possibly a market coordinating and congestion management platform to safeguard network power quality, security, reliability and safety at least cost.

Driving Smart Meter Investment to Deliver First Wave and Second Wave Reform

The AEMC's 2015 Competition in Metering rule change will essentially enable a roll out of advanced metering over time via new and replacement meters from 2017. This, coupled with the already in place Victorian AMI rollout means that an increasingly large number of customers can transition to cost reflective prices without having to voluntarily change out their meter.

However, there is to date no requirement for any customer with an advanced meter to also be assigned to a cost reflective tariff, implying that a large proportion of the advanced meter's potential benefits, in delivering cost reflective pricing, may go unrealised.

The modelling demonstrated that under the base case, approximately 76% of smart meter customers will not have adopted any form of cost reflective tariff by 2026, improving slightly to 60% of smart meters by 2050. This implies that the benefits of approximately $1.5B of smart meter investment by 2026 and $2.7B of smart meter investment by 2050, will not have been realised.

Under Scenario 3, 4, 5 and 6 which introduce First Wave tariff reform on an opt-out basis in 2021, the benefits of smart meter investment are able to be better leveraged. Under these scenarios, approximately 94% of smart meters installed are also delivering cost reflective tariffs by 2026 and 98% by 2050.

There are a range of policy and logistical challenges to the realisation of these benefits. The modelling assumes deployment of around 4.3 million advanced meters, at an approximate cost of $1.1B[4], can occur in conjunction with the mass tariff assignment in 2021.

The need for such a rapid deployment would be avoided if market led metering deployments are successful in achieving significant meter deployment before 2021. However, should it fail to eventuate by 2021, the modelling suggests further meter deployment would be rapidly required at scale to secure the potential benefits available to customers.

Network Reform in the Context of Meeting Australia's Climate Commitments

The carbon prices used in the modelling reflect CSIRO's estimate of the levels required to achieve the 2030 emission reduction targets and to approach near zero net emissions by 2050. Generation sector emission reduction will have material impacts on the wholesale cost of electricity regardless of the implementation mechanism adopted. Where the effect of the carbon price is passed through to consumers via a flat volume retail tariff component (as assumed in the modelling), there is a strong incentive for uptake of solar PV which in turn leads to large scale battery storage uptake in order to "solar shift" to utilise exports.

The impact of climate policy represents a challenge for network tariff reform. Even while network tariffs become more cost reflective to reduce reliance on volume-based charges, the retail tariff could significantly increase its reliance on volume-based charges to reflect the impacts of the carbon price on generation costs. While not modelled, there are actions retailers could be expected to take to improve the cost reflectivity of their own tariff components, including time-of-use pricing and/or dynamic feed-in tariffs.

Recommendations

Based on the results of the modelling, Energeia recommends that CSIRO/ENA consider the following recommendations as part of the ENTR Roadmap:

1 That opt out (rather than opt-in) tariff assignment frameworks be implemented as early as possible by regulators and network service providers as they deliver substantial economic benefit compared to status quo arrangements

2 That Australian Energy Market Commission, as part of its annual monitoring and reporting to COAG on technology trends and changes in market conditions, report on the pace of market led smart meter deployment to ensure that it is on track to deliver the required number of meter installations to transition to an opt-out tariff assignment framework from 2021.

[4] Assuming $250 for meter and installation costs

3 That all DNSPs continue to refine cost reflective tariff mechanisms so as to limit cross subsidies and the creation of new peaks from battery storage. Robust structures should ideally be in place by 2021 and earlier where possible

4 That DNSPs consider more sophisticated tariff options in the medium term to deal with the likely penetration of new technologies. These include tariffs that allow for operational access to distributed energy resources on a dynamic basis in exchange for lower prices

5 That the AER consider the potential impact of emerging technology and in particular battery storage in approving DNSPs tariff structures as part of the Tariff Structure Statement (TSS) process and in doing so allow for the potential for refinement in tariff structures prior to the expiry of current TSS periods

6 That policy makers consider any regulation change necessary to allow tariffs to be refined more frequently than allowed for under the existing tariff structure statement cycle (which effectively locks in structures for five years) in the context of the current dynamic and changing environment

7 That the roadmap considers options towards the implementation of platforms to enable more granular pricing and incentive mechanisms. This should in the first instance enable network orchestration of discretionary loads and distributed generation on an opt-in basis to be in place from 2021 with the capability to integrate with more transactive mechanisms such as either real time incentives or location marginal pricing from 2026, should this be required

8 That DNSPs engage with retailers as soon as possible to identify integrated, cost reflective tariffs and incentive mechanisms that will better manage the identified issues along the path towards Australia's climate commitments

Disclaimer

While all due care has been taken in the preparation of this report, in reaching its conclusions Energeia has relied upon information provided third parties as well as publically 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.

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1 Introduction

1.1 Background

CSIRO and the ENA (CSIRO/ENA) are partnering to develop an electricity Network Transformation Roadmap (NTR), 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
- 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 tariff reform (including tariff settings as well as market and policy settings) have the potential to respond to the challenges of integrating distributed energy resources (DER) to improve customer outcomes.

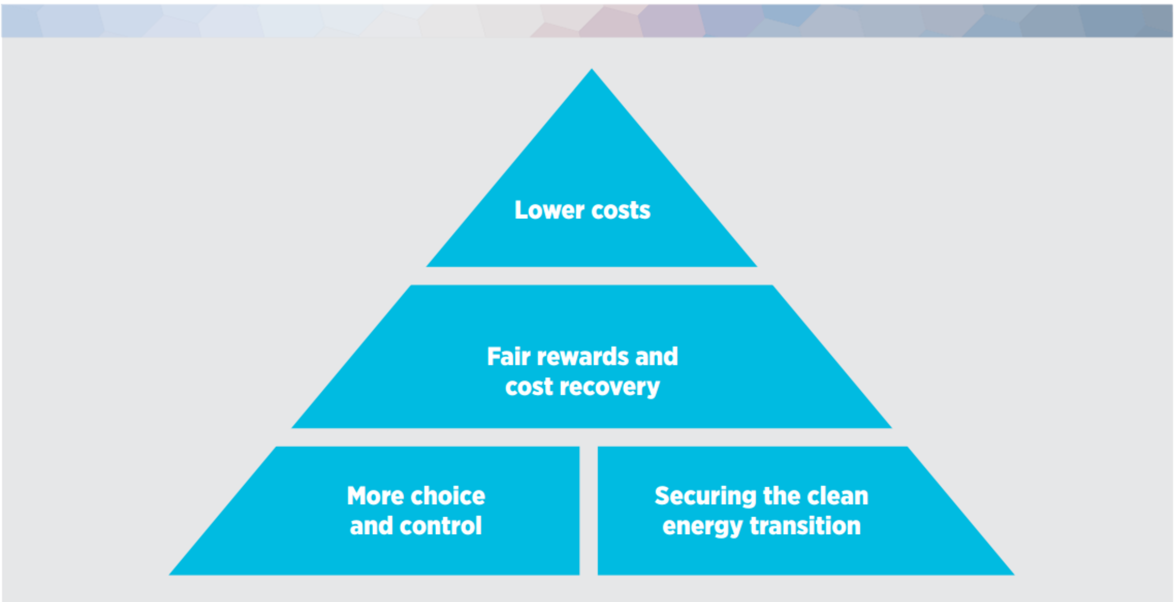
This report is one of a series of reports produced by Energeia as part of the NTR, all of which aim to provide the evidence base to underpin recommendations for action by Australia's electricity sector over the Roadmap period.

This report focusses on the "First Wave" and "Second Wave" reform phases in distribution network pricing and meter migration.

1.2 Purpose and Objectives

The overall objective of this report is to assist ENA/CSIRO to potential roadmap measures related to integrated electricity pricing and incentive reforms which promote key principles of ***efficiency, equity, simplicity, stability, viability*** and ***minimised cross subsidies***[5] and also aligned to the Balanced Score Card (presented in Figure 10) adopted for the purposes of the NTR.

Figure 10 – CSIRO Balanced Scorecard



Source: CSIRO

Specifically, this report seeks to:

[5] The Brattle Group (2014) Time-varying and dynamic rate design, Global Power Best Practice Series, July 2014

1. Quantify the impact of “First Wave” tariff and meter migration reform options on the overall efficiency of Australia’s electricity system.

   For the purposes of this report, First Wave reforms refer to the range of tariff structures and tariff assignment mechanisms currently being contemplated by distribution network service providers (DNSPs) including maximum demand tariffs and the range of triggers for tariff assignment.

2. Quantify the potential benefits of “Second Wave” reform options encompassing dynamic and locational price signals and the concepts of transactional energy.

   For the purposes of this report, “Second Wave” reforms refer to the range of tariffs and other forms of incentives and procurement methods including contracting and transactional platforms which provide dynamic price signals.

The report is largely focussed on the role of *network* tariff reform in delivering more efficient outcomes for the energy system as a whole. Although the report includes consideration of retail tariffs, wholesale generation prices and emerging issues in these sectors, it does not specifically address what actions can be taken by these stakeholders to contribute to a more efficient energy system. There are many opportunities which, if integrated with network tariff reform and incentives, may provide even greater economic value over the medium to long term.

1.3 Report Structure

The report is structured as follows:

- **Section 1 –** Provides the background and overall objectives of the report
- **Section 2** – Outlines the relevant policy and legislative context and key industry stakeholder views
- **Section 3 –** Provides a summary of the approach taken for the modelling
- **Section 4 –** Provides a summary of the modelling results
- **Section 5** – Presents the conclusions and recommendations for potential roadmap measures

1.4 Limitations

The results, conclusions and recommendations contained in the report are based on the outcomes of Energeia's behind-the-meter to generator simulation platform and are therefore limited by the scope, assumptions and modelling inputs qualified throughout these reports. The material modelling limitations are documented below.

The modelling was driven by six key scenarios which by no means cover the full range of potential tariff reform pathways. Indeed, the six scenarios modelled revealed weaknesses in each of the tariff reform pathways modelled. Whilst, some fine tuning was able to be undertaken by a series of iterative model runs, the study did not attempt to identify optimal tariff structures and assignment mechanisms for each of the 14 networks. Notwithstanding, the modelling identified potential opportunities for optimisation and direction for DNSPs to explore as part of future tariff design activities.

With respect to Second Wave reform, it is recognised that there are a number of mechanisms beyond primary tariff reform which can deliver dynamic and locational price signals with respect to both export and import of electricity. The modelling is not specific as to which mechanism delivers the Second Wave outcomes and is more concerned with identifying the benefits of truly cost reflective dynamic and locational price signals for investment and operation of DER.

The model is a techno-economic model and is focussed of changes in demand at the zone substation level and the corresponding impacts on network costs. Network costs are therefore limited to consideration of replacement and augmentation driven by changes in demand as a result of customer behaviour. The model does not consider network costs driven by changes in power quality or changes in thermal ratings as a results of changes in DER uptake which would require further engineering analysis beyond the scope of this project.

The majority of modelling input assumptions were provided to Energeia by CSIRO, developed as part of its broader stakeholder consultation for the Future Grid Forum and Part I of the Electricity Network Transformation Roadmap. Critical assumptions include technology cost declines, network costs, consumer uptake propensity, generation build-out and broader geopolitical and macroeconomic trends influencing oil and gas prices and carbon prices (Graham et al 2015). No sensitivities to these inputs were able to run in the timeframe.

The modelling was also dependent of inputs from DNSPs in the form of zone substation load profiles and is therefore subject to any errors in these inputs. In particular, approximately 25% of network zone substations were excluded from the analysis due to either being missing[6] or containing obviously erroneous data. Notwithstanding, load at these zone substations was considered within a balancing item for the purposes of the wholesale market model,

Further, any large industrial customers were excluded from the analysis. These customers' loads were also included within a balancing item for the purposes of the wholesale market model. As a result of the limitations

[6] For commercial confidentiality reasons, zone substations were deliberately excluded by DNSPs where only one customer, typically a large industrial facility, is connected.

above, approximately 40% of NEM load was assigned to a balancing item and unaffected by customer decisions with respect to DER or tariff uptake.

The modelling accordingly focusses on the behaviour of commercial, small business and residential electricity consumers with respect to technology adoption operation and usage patterns. It does not attempt to determine the extent to which changes in the large scale commercial and industrial segment will impact long term outcomes for the energy system other than those changes assumed by the Australian Energy Market Operator in its National Electricity Forecasting Report. Any material departure from these forecasts in terms of major shifts in the Australian economy away or towards more energy intensive industries, or broad scale technological change in these industries has not been considered and may be material to the results.

Despite these limitations, the modelling is considered to have the broadest coverage and greatest granularity of any modelling of the Australian electricity sector undertaken to date. The model provides, for the first time annual forecasts of demand and consumption and DER uptake at the zone substation level for all of Australia as well as the corresponding changes in network and wholesale costs and the feedback to network and retail prices. To the best of Energeia's knowledge, this has not been previously achieved in Australia or indeed, in any other country, to date.

2 Policy and Industry Context

2.1 Tariff Reform and Distributed Energy Technology

In recent times, there has been increasing pressure on the electricity industry to change the way in which it charges for electricity to improve the overall efficiency, equity and ultimately affordability for consumers. Much of this pressure has been driven by changes in the way in which consumers use energy and the emergence of new distributed energy resource (DER) technology consuming and generating electricity at the customer premise, combined with increasingly sophisticated monitoring, metering and control technology.

Historically, energy consumers were considered as largely homogenous, essentially consuming energy in the same way, and thus imparting the same costs on the system dependent on their type (business or residential) and size alone. However, with the advent of new technologies, the customer base has become increasingly heterogeneous in terms of consumption profiles and corresponding costs for the network to supply. Many commentators[7] have identified that, in such an environment, flat tariffs are no longer an equitable basis on which to charge consumers as well as potentially over-incentivising investment in energy technology.

2.1.1 Impact of Solar PV Penetration

The sharp rise in roof-top solar PV connections over recent years has arguably been the strongest driver of rising heterogeneity. As of June 2016, there were over 1.5 million grid-connected solar PV systems in Australia primarily driven by the residential market with 16% of dwellings now fitted with a solar PV system[8]. Solar PV investment to date has been largely driven by state based feed-in-tariffs, but further assisted by consumption-based network and retail tariff price structures which over-signal the value of reducing grid sourced consumption through solar PV generation to the network.

Table 1 – Solar PV Penetration

State	Installations	Dwellings (%)	Capacity (MW)
QLD	484,316	30.3%	1,585
SA	199,198	29.4%	683
WA	207,596	23.5%	622
VIC	293,400	14.7%	957
NSW	342,303	14.6%	1,301
ACT	17,023	13.4%	76
TAS	27,450	12.5%	97
NT	5,927	9.5%	39
TOTAL	**1,577,213**	**16.3%**	**5,360**

Source: APVI

While solar PV enables customers to reduce their grid consumption, it does not necessarily decrease their peak demand and cost to serve by the same extent. This effect is particularly evident for residential customers whose peak consumption tends to fall outside of the solar generation hours. A reduction in grid consumption does not

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[7] See for example:

Simshauser, P., Downer, D,, On the inequity of flat-rate electricity tariffs, AGL Applied Economic and Policy Research Working Paper No. 41 – Inequity of Tariffs, 2014. Last accessed on 13th April 2014, http://aglblog.com.au/wpcontent/uploads/2014/07/No.41-On-the-inequity-of-tariffs.pdf

Energy Networks Association (2014), *Towards a National Approach to Electricity Network Tariff Reform, ENA Position Paper*, December 2014. Last accessed on 13th April 2014, http://www.ena.asn.au/sites/default/files/position-paper_towards-a-nationalapproach-to-electricity-network-tariff-reform_december-2014_1.pdf

Wood, T., Carter, L (2014) *Fair Pricing for Power*, Grattan Institute, July 2014 https://grattan.edu.au/report/fair-pricing-for-power/

[8] Australian Solar Photovoltaic Institute Solar Maps http://pv-map.apvi.org.au/historical#4/-26.67/134.12

result in a commensurate fall in network costs which have a stronger relationship to peak demand and recovery of past investment to meet peak demand growth. In networks with high solar penetration, reduced consumption has resulted in a requirement for the network to increase volume prices in order to recover revenue and the emergence of substantial cross subsidies between customers who adopt solar PV and those that do not.

2.1.2 High Cost to Supply Equipment and Appliances

Solar PV is not the only technology driving such cross subsidies. Energy consuming equipment and appliances such as air conditioners or heating, used intensively for only part of the year or part of the day, have a tendency to increase peak demand on the network without a commensurate increase in the network prices paid by the consumer. In summer peaking networks with a high penetration of air conditioning units, prices have historically risen order to recover these additional costs leading to cross subsidies between customers who adopt such equipment and those who do not. The same effect can be observed due to heating units in winter peaking networks.

2.1.3 Emergence of Battery Storage Technology

Now, as the costs of battery storage technologies continue to fall, and the performance of batteries improves, new pricing challenges and opportunities are emerging. Battery storage provides customers with flexibility to shift load and reduce peak demand through timely charging and discharging of the unit to and from the grid. The ability of storage to target peak demand has large potential to assist in reducing a network's cost by offsetting customer's own peak demand and even exporting during critical network peak periods.

However, battery storage technologies as well as automated energy management systems have the ability to deliberately exploit a tariff and, once installed, act as the ultimate economically rational customer, dynamically charging and discharging to the grid in order to maximise customer financial return on investment. Accordingly, there is an increasing need for tariffs to signal system costs as closely as possible or else there is the potential for significant cross subsidies, and long term inefficiencies to emerge.

2.2 Legislative Context

2.2.1 National Electricity Rules and National Electricity Law

The overarching legal framework for Australia's National Electricity Market (NEM) is provided by the National Electricity Law (NEL). The NEL has been adopted by all States (with the exception of Western Australia[9]), the Australian Capital Territory and the Commonwealth of Australia (together, 'the participating jurisdictions'). It is important to note that changes to the NEL can only be made if all the energy Ministers of all the participating jurisdictions agree to make the change.

Importantly Section 7 of the NEL contains the National Electricity Objective (NEO):

> *To promote efficient investment in, and efficient operation and use of, electricity services for the **long term interests of consumers of electricity** with respect to:*
>
> *a) Price, quality, safety, reliability and security of supply of electricity; and*
>
> *b) The reliability, safety and security of the national electricity system.*

Any decisions made by policy makers and the regulators with respect to the operation of the NEM must have regard to the NEO.

The National Electricity Rules (Rules) are made under the NEL and provide (amongst other things) the framework and process for pricing regulated network services in the national electricity market.

[9] On 22 June 2016, the Western Australian Government introduced a package of legislation into Parliament to adopt the National Electricity Law regulatory scheme. This is to be achieved through the National Electricity (Western Australia) Bill 2016, and the Energy Legislation Amendment and Repeal Bill 2016. Transitional arrangements will facilitate regulation of Western Power's transmission and distribution network by the Australian Energy Regulator from early 2017, with the new regulatory framework commencing from 1 July 2018.

Since 2008, the distribution networks in the NEM states have been regulated by the Australian Energy Regulator (AER). The AER is responsible for determining revenue allowances for networks on a five year basis to cover network costs associated with:

- Operation and maintenance expenditures
- Return on capital
- Asset depreciation
- Tax liabilities

The overall revenue allowance is then recovered via network prices. Currently all distribution networks within the NEM are subject to a revenue cap which means that the networks must set prices to ensure they neither under- or over-recover their five-year revenue allowances.

In recent years, network consumption, and therefore revenue base when recovered using consumption based tariffs, has been declining driven by uptake of solar PV, energy efficiency, as well as broader macroeconomic factors. Network prices have accordingly risen as a result of systematic under-recovery of network revenue. During the last regulatory period, this effect was responsible for almost 50% of the price rises observed in Queensland.

2.2.2 Network Pricing Principles

In November 2014, the AEMC amended Chapter 6 of the National Electricity Rules such that distributors are now guided in setting tariffs by the “Network Pricing Objective”. The objective calls for distribution tariffs to reflect the distributor’s efficient costs of providing its services to its customers. The network pricing objective is supported by pricing principles under the Rules.

- **Stand Alone and Avoidable Cost Principle -** The revenue expected to be recovered from each tariff must be greater than the avoidable cost and less than the standalone cost of the service
- **Long-Run-Marginal-Cost Principle -** Network tariffs must be based on the long run marginal cost (LRMC) of providing the service.
- **Total Efficient Cost Principle -** The revenue expected to be recovered from each network tariff must: reflect the distributor’s total efficient costs of providing services to the customers assigned to that tariff; permit the distributor to recover its expected revenue in accordance with its regulatory determination; and be recovered in a way that minimises distortions to the pricing principles
- **Customer Impact Principle -** Distributors must consider the impact on customers of changes in network charges and set tariffs that they are reasonably capable of understanding (simplicity).

Network businesses must comply with the pricing principles in a way that contributes to the pricing objective. Distribution businesses may depart from the cost reflectivity principles to the extent necessary to comply with the consumer impact and jurisdictional obligations principles so long as any departures are explained in a transparent way.

The effect of the rule change requires networks to develop cost reflective prices with respect to the peak charging (based on LRMC) mechanisms and residual charging mechanisms for all tariff classes.

What is a Peak Charge?

Network investment is driven by the maximum demand required by all customers each year across each network asset, known as coincident peak demand. The magnitude and timing of coincident peak demand varies depending on the location within the network and the types of customers that are connected to it.

The incremental cost of meeting an additional unit of network demand at peak is known as Long Run Marginal Cost (LRMC). Under a cost reflective tariff, a customer is charged at LRMC for every unit of demand they place on the system at peak times, known as the peak charge.

The peak charge incentivises customers who want to save money to invest in demand management technologies or change their behaviour at peak times only to the extent that it is cheaper (or more valuable to the customer) than the cost of increasing network capacity.

A cost reflective peak charge set at LRMC produces the most economically efficient result with the least amount of deadweight loss. If the peak charge is set above LRMC then customers are incentivised to forego beneficial demand or use higher cost alternatives, which increases deadweight losses in the system. Conversely, if the peak charge is set below LRMC, customers would be incentivised to over-consume network capacity or forego less expensive options.

What is a Residual Charge?

In addition to the costs of supplying peak demand, networks must recover residual costs, due mainly to fixed and sunk costs in existing network infrastructure. To allow for this, a cost reflective network tariff must also have an efficient residual charge component. There are a range of options for the structure of residual charges including fixed charges, demand charges, energy charges or a mixture of each.

An efficient residual charge is generally set outside of peak periods so as not to influence the peak charge and should not further distort customer investment behaviour.

From a theoretical perspective, fixed charges are advocated as the best means of recovering residual costs as they remain constant no matter what the customer behaviour. However, recovery of residual costs via fixed charges alone has three main shortfalls. Firstly, fixed charges can disadvantage small, and potentially vulnerable consumers. Secondly, fixed charges may inadvertently drive disconnection from the network if set too high and place an additional burden on energy consumers who remain connected to the grid. Thirdly, since a fixed charge cannot be avoided it reduces the incentive for energy efficiency as a customer response to minimising electricity bills.

2.2.3 Tariff Structure Statements

As part of the 2014 Rule Change, the AEMC introduced a requirement for distribution networks to publish Tariff Structure Statements (TSS) which outline:

- Tariff classes;
- Tariff structures;
- Policies and procedures for assigning consumers to tariffs; and
- The approach to setting tariff pricing levels that each network proposes to apply over the five-year regulatory control period.

The TSS must comply with the pricing principles. However, distributors can depart from the three efficient cost principles (for standalone and avoidable cost, LRMC, and total efficient costs), to the extent necessary to meet the consumer impact and jurisdictional pricing obligation principles. If a distributor needs to make any such departure to meet jurisdictional pricing obligations, then it must do so transparently and only to the minimum extent necessary.

As of July 2016, each of the distribution networks has submitted a TSS, but at the time of writing none had been formally approved by the Australian Energy Regulator[10]. Each of the DNSP's TSS have proposed forms of cost reflective pricing for mass market customers as well as tariff assignment mechanism.

Almost all networks with the exception of NSW Networks have proposed some form of demand based tariffs for mass market customers, with the structure varying by network[11]. Networks also proposed various tariff assignment approaches. These are summarised in Table 2 below.

[10] Note draft decisions were released on 2nd August 2016 approving TSSs for Ergon, Energex, Ausnet, UED,

[11] Note, NSW distribution networks have proposed declining block tariffs and at this stage have not proposed any demand based tariff

Table 2 – Proposed Cost Reflective Network Tariffs for Mass Market Customers[12]

State	DNSP	Peak Charge					Residual Charge					Tariff Assignment Mechanism
		Peak Demand (Max Monthly Half Hourly) ($/kW)	Seasonal Peak Demand (Max Monthly Half Hourly during Peak Seasons) ($/kW)	Peak Demand (Average Top Four Monthly Half Hourly Demand) ($/kW)	Minimum Demand ($/kW)	Peak Energy ($/kWh)	Fixed ($/day)	Anytime Energy ($ per kWh)	Off Peak Energy ($ per kWh)	Shoulder Energy ($ per kWh)	Off Peak Demand (Max Montlhy Half Hourly) ($ per kW)	
QLD	Energex	✓					✓	✓				Opt-in
	Ergon			✓	✓			✓				Opt-in
NSW	Ausgrid		✓			✓	✓	✓				Opt-in
	Endeavour					✓	✓		✓	✓		Opt-in
	Essential Energy					✓	✓		✓	✓		Opt-in
	ActewAGL		✓			✓	✓	✓				Default
VIC	Citipower		✓				✓	✓			✓	Opt-in
	Powercor		✓				✓	✓			✓	Opt-in
	Jemena		✓				✓	✓			✓	Opt-in
	Ausnet		✓				✓	✓			✓	Opt-in
	United Energy		✓		✓			✓			✓	Opt-in
SA	SA Power Networks		✓		✓			✓				Default
TAS	TasNetworks		✓				✓				✓	Opt-in
WA	Western Power					✓	✓		✓	✓		Opt-in

[12] Draft DNSP Tariff Structure Statements, various https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs

2.2.4 Competition in Metering

In December 2014, the AEMC amended Chapter 6 of the NER to change who has overall responsibility for metering in order promote competition in the provision of metering and related services. As a result of the rule change, as of December 2017, a new type of registered participant in the NEM, known as a Metering Coordinator will come into place responsible for the provision of metering services. The retailer will be required to appoint the Metering Coordinator whenever a new or replacement meter is installed at a premise. This will replace the current arrangements whereby the network service provider is responsible for metering services.

The implications of the metering rule change for tariffs are important. One of the key barriers to the deployment of cost reflective tariffs is the lack of advanced metering infrastructure to enable interval metering, a prerequisite for billing of cost reflective pricing.

The rule change requires that all meters installed by the Metering Coordinator meet a minimum advanced metering specification, thus enabling cost reflective tariffs. The rule change essentially enables a roll out of advanced metering overtime (albeit much more slowly than the Victorian AMI program) via new and replacement meters such that a growing number of customers can transition to cost reflective prices without having to voluntarily change out their meter.

Notwithstanding, there is to date no requirement for any customer with an advanced meter to be assigned to a cost reflective tariff, implying that a large proportion of the advanced meter's potential benefits, in delivering cost reflective pricing, may go unrealised. It should be noted that some networks draft TSSs have proposed mandatory assignment of customers to cost reflective tariff at the time they are provisioned with an advanced meter (see Section 2.2.3).

2.3 Stakeholder Views

2.3.1 Need for Reform

A broad range of stakeholders have indicated strong support for urgent transition to cost reflective tariffs[13]. While stakeholders hold mixed views as to the appropriate tariff structures, cost allocation and transition mechanisms, what is largely agreed is that the range of existing tariffs, dominated by kWh volume based charges, which are already and will continue to lead to inequitable and inefficient outcomes for all consumers.

In December 2015, the ENA released its Tariff Reform Handbook setting out a transition pathway towards full cost reflectivity starting with a move to "First Wave" tariffs, reflecting the current batch of network proposed demand based tariffs (See Table 1). The ENA also acknowledges that refining these tariffs in the short term will be required as more information and learnings on customer preferences and responses are gathered.

The Tariff Reform Handbook also suggested that, although First Wave reforms will provide improved signals for customers, full optimisation of DER and smart technologies, along with the growing diversity of customers' electricity consumption and production, might require a "Second Wave" of tariff and incentive reforms through to 2025. Second wave tariff reforms incorporate more granular, time and location differentiated cost reflective pricing signals, which are a step change more cost reflective than First Wave tariffs. They enable a greater customer choice, and ensure more effective DER integration into the network, reducing future network costs while ensuring grid resilience and reliability for the ultimate benefit of customers.

These views were echoed in Stage 1 of the ENA/CSIRO Network Transformation Roadmap.

2.3.2 Demand Based Tariff Design

There are a range of potential design options for the structure of a demand based tariff. As shown in Table 2, the majority of distribution networks have proposed a demand based tariff for residential and small business customers using a single 30 minute period (the customer's own peak demand for each peak month) as the basis for the peak charge.

[13] Ibid. 6

However, there are a range of views as to the effectiveness and efficiency of such a signal in terms of:

- Sending price signals to customers that are more closely aligned with the network's coincident demand[14,15]
- Enabling customers to respond to price signals
- Avoiding or manage the potential for a customer to face 'bill shock'.

The AER, in its draft decision on DNSP Tariff Structure Statements[16] suggested that alternative approaches[17] to the design of peak demand charges, which align to network's co-incident demand, may better achieve the above objectives.

2.3.3 Impacts on Vulnerable and Other Specific Customer Groups

Perhaps the largest barrier to First Wave network tariff reform is stakeholder perceptions of customer impacts. Large scale transition to cost reflective network tariffs will create winners and losers. Low cost to serve customers will likely see improved bill outcomes under cost reflective tariffs, while high cost to serve customers will likely see higher bills, at least initially. However, identifying low cost and high cost to serve customer groups is often extremely difficult due to the lack of customer specific interval meter data, especially in states with relatively low penetration of interval meters.

Perhaps the largest study identifying impacts of cost reflective tariffs on vulnerable customers has come from AGL utilising its Victorian residential customer smart meter data combined with demographic data to identify the impact of demand based tariffs on Hardship and Concession and Pensioner Households.[18] The study concluded that vulnerable customers are in fact *more* likely than other customers to benefit from cost reflective pricing once demand response is accounted for. However, it should be noted that the data used was drawn predominantly from AGL's Victorian customer base and assumes that all customers are able to exhibit some level of behavioural response to demand based signals.

In its Electricity Pricing Inquiry, the Queensland Government raised specific concerns with respect to the impact of transitioning to cost reflective network tariffs on vulnerable customers. The Inquiry sought to prioritise additional data collection and analysis to better understand the potential impacts of tariff reform and the ability of vulnerable customers to respond to price signals, with income and housing tenure as the two most frequently cited barriers to efficient and equitable uptake of demand management.

2.3.4 Providing a Fair Price for Distributed Generation

With many of the existing government incentives for DER being phased out, governments are looking for ways to adequately compensate distributed generators for the value they can provide to networks when exporting. In the absence of other mechanisms, policy makers are looking towards broad based export tariff as the potential

[14] Davies, M., (2016) Pitfalls of Domestic Customer Electricity Demand Management, August 2016 http://www.wattclarity.com.au/2015/08/pitfalls-of-demand-management-for-the-domestic-electricity-consumer/

[15] Passey, R., Haghdadi N., Quantifying the Mismatch in Current Demand Charge-Based Network Tariffs, July 2016

[16] See for example, AER (2016), Draft Decision Tariff Structure Statement Proposal SA Power Networks, August 2016 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/sa-power-networks-tariff-structure-statement-2015

[17] The AER references the Ergon Energy approach of adopting the four average four highest demand periods as the basis of calculating the demand charge for its residential customers as a potential improved alternative and states that it "*would be interested in working through this issue with the industry and stakeholders in the lead up to the next round of tariff structure statements*"

[18] Simshauser, P., Downer, D,, On the inequity of flat-rate electricity tariffs, AGL Applied Economic and Policy Research Working Paper No. 41 – Inequity of Tariffs, 2014. Last accessed on 13th April 2014, http://aglblog.com.au/wpcontent/uploads/2014/07/No.41-On-the-inequity-of-tariffs.pdf

solution to this policy and regulatory gap. This is evidenced in a number of current and recent consultations exploring options.

Victorian Government Inquiry into the True Value of Distributed Generation

The Victorian Government is currently carrying out an inquiry into the true value of distributed generation. The Inquiry involves two stages; the first focussing on the energy value of distributed generation, and the second on network value and the extent to which the economic, social and environmental benefits are signalled to those investing in and operating distributed generation systems. In terms of network value, the inquiry is seeking to identify and quantify the network value of distributed generation, assess the extent to which the current regulatory framework takes this value into account, and recommend any changes to the regulatory framework necessary to better account for the network value of distributed generation.

While the inquiry is yet to be finalised, stakeholder submissions have focussed on a number of relevant issues to this paper including that:

- Existing regulatory mechanisms do not adequately signal the full value of behind the meter distributed generation to the network and that pricing mechanisms may be one such way to signal this value[19]
- The network value of distributed generation is both temporally and spatially dependent and varies with feeder characteristics and the level of existing DER penetration, such that any export tariffs would need to be dynamic and locational[20,21,22]
- There are a range of regulatory mechanisms outside of tariffs both in place and under consideration that go some way to signalling network value of distributed generation[23]
- Until such time as import tariffs are fully cost reflective, a fully cost reflective export tariff may create 'cherry picking' and lead to further inefficiencies[24].

[19] Clean Energy Council, Clean Energy Council Submission to the Essential Services Commission's Distributed Generation Inquiry Stage 2 Discussion Paper The Network Value of Distributed Generation, 29 July 2015 http://www.esc.vic.gov.au/wp-content/uploads/2016/08/Clean-Energy-Council-Subm-to-DG-Inquiry-Network-Discussion-Paper-20160801.html

[20] Australian Energy Council, The True Value of Distributed Generation to Victorian Consumers Discussion Paper, 29 July 2016 http://www.esc.vic.gov.au/wp-content/uploads/2016/08/Australian-Energy-Council-Subm-to-DG-Inquiry-Network-Discussion-paper-20160801.html

[21] CitiPower, PowerCor, Inquiry into the True Value Of Distributed Generation: Network Value Discussion Paper, , 29 July 2016 http://www.esc.vic.gov.au/wp-content/uploads/2016/08/Citipower-Powercor-Subm-to-DG-Inquiry-Network-Discussion-paper-20160801.html

[22] Ausnet, Inquiry into the True Value of Distributed Generation, Stage 2 – The Network Value, 29 July 2015 http://www.esc.vic.gov.au/wp-content/uploads/2016/08/AusNet-Services-Subm-to-DG-Inquiry-Network-Discussion-paper-20160801.html

[23] Energy Networks Association, The Network Value of Distributed Generation Inquiry, Response to Essential Services Commission's Discussion Paper, 29 July 2016 http://www.esc.vic.gov.au/wp-content/uploads/2016/08/Energy-Networks-Association-ENA-Subm-to-DG-Inquiry-Network-Discussion-paper-20160801.html

[24] n20

Queensland Government Inquiry into a Fair Price for Solar

The Queensland Government has also recently concluded its inquiry into a "Fair Price for Solar." While the review focussed predominantly on the energy value of solar, it acknowledges that there exists localised network benefits from solar PV. The draft findings of the review suggest that network benefits from solar PV are best harnessed through mechanisms that can efficiently and effectively target these benefits, rather than paying all solar PV owners a uniform feed-in tariff unrelated to network impacts, effectively signalling that it will not be offering a broad based export credit.

Local Generation Network Credits Rule Change Request

Finally, the AEMC is currently considering a Rule Change Request to introduce Local Generation Network Credits proposed by the Total Environment Centre and the City of Sydney. The Rule Change, if implemented, would require DNSPs to pay embedded generators a broad based credit (a negative network tariff) that reflects the long-term economic benefits provided to distribution and transmission networks.

The rule change process is not yet completed. Stakeholder submissions have focussed on a number of relevant issues, broadly similar in nature to those raised in the Victorian Government Inquiry including that:

- There is a missing price signal where there are network benefits from embedded generation[25]
- The costs and benefits of embedded generation are likely to be highly dynamic and locational and without sufficient granularity, the LGNC may incentivise inefficient investment and operation of embedded generation or potentially impose net costs on networks
- The LGNC does not account for material locational differences, and is not symmetrical[26]
- It is possible that transaction costs may easily outweigh benefits if this is not well managed[27].

2.3.5 Transitioning to "Second Wave" Reform

The need for a Second Wave of reform was put forward by CSIRO and the ENA in their Network Transformation Roadmap: Interim Program Report[28] referring to the range of pricing signals and incentives which are location specific and/or dynamic in real time. In doing so, CSIRO and ENA have put forward that Second Wave reform can:

- Address the issues of cross subsidies and economic inefficiencies with respect to current tariffs
- Provide a mechanism to incentivise economically efficient distributed generation, beyond the current considerations of broad based credit mechanisms (as discussed in Section 2.3.4)

The ability of the network to optimise the flow of energy across the grid at times of over or under capacity, both dynamically and at specific locations, at least cost, will become increasingly important with the introduction of new technologies and the changing mix of centralised and decentralised energy evolves.

Second Wave reform covers a range of different pricing signals and incentives to integrate available DER with traditional grid services, some of which are outlined in the blue box below. The range of options for Second Wave reform span from control of discretionary loads or storage through to more sophisticated transactive mechanisms. While highly cost reflective, there are a range of barriers to implementation of Second Wave incentives. Firstly, to the extent that the incentive incorporates dynamic locational pricing, highly dynamic and potentially uncertain pricing signals need to be established. If these signals are directly passed through to the

[25] Clean Energy Council, ERC0191 Local Generator Credits Rule Change, Consultation Paper Submission, 9 February 2016 http://www.aemc.gov.au/getattachment/e72c83ac-fdac-4631-9eeb-10e54fba564a/Clean-Energy-Council-8-February-2016.aspx

[26] Frontier Economics, Valuing the Impact of Local Generation on Electricity Networks a Report Prepared for the Energy Networks Association (February 2015) http://www.aemc.gov.au/getattachment/6916f3a3-31d9-457b-8228-5530b64e1fcf/Energy-Networks-Association-Frontier-Economics.aspx

[27] n25

[28] CSIRO and Energy Networks Association 2015, Electricity Network Transformation Roadmap: Interim Program Report.

customer, they may be complex for the customer to understand, predict and to respond to appropriately. Secondly, locational pricing requires investment in metering, monitoring, control and automation technology as well as additional transactional costs. The benefit of dynamic locational pricing therefore needs to be balanced against these costs.

Notwithstanding, CSIRO and ENA in their Interim Program Report suggest that there are great benefits from Second Wave reform in an environment of high DER penetration, allowing for full optimisation of DER as well as offering new service providers and customers the opportunity to participate in emerging energy markets.

The concept of locational and dynamic pricing incentives has been broadly discussed and various mechanisms trialled by networks and retailers over time, including critical peak pricing and dynamic peak rebates[29]. More sophisticated platforms for real time pricing have also been raised by certain stakeholders including the concepts of transactive energy platforms, virtual power plants and the evolving role of distribution system operators. However, the debate as to the right mechanism for Australia's energy market is still in its infancy.

In other jurisdictions, facing similar DER integration issues, options for transactive energy platforms at the distribution level are being proposed. For example, New York's *Reforming the Energy Vision* has the local utility transforming into a Distribution System Platform" provider (DSP) optimising behind-the-meter distributed energy resources for the benefit of the distribution system. An alternative "independent distribution system operator" (IDSO or just DSO), has also been proposed for New York acting as an *independent* market-maker for to buy and sell energy services, without owning *any physical assets itself*.[30]

In Australia, ARENA has recently announced the trial of a Virtual Power Plant project, providing $5 Million in funding to a $20M trial to be undertaken by AGL in South Australia. The VPP trial will involve AGL operating a network of 1,000 battery storage solutions at customer premises, controlling the charging and discharging patterns of the solutions according to price signals provided by both wholesale and ancillary services markets and regulated networks in exchange for an upfront incentive to the customer[31].

[29] See for example *Smart Grid, Smarty City (*2015) and Ergon and Energex Rewards Based Tariff Trial (2011-2013)

[30] Kristov, L., De Martini, P., (2014) 21st Century Electric Distribution System Operations, Caltech Resnick Institute, May 2014

[31] See http://arena.gov.au/media/battery-storage-set-strengthen-south-australian-grid/

Second Wave Reform

Second Wave Reform refers to the range of mechanisms that deliver pricing signals and incentives that are location specific and/or dynamic in real time. Key terminology relating to various mechanisms for second wave reform are explained below:

Critical Peak Price (CPP) – A predetermined price, significantly higher than other times, is applied over 4-8 hours for a set number of events per year. The events can be called in response to network and or wholesale market peaks with consumers given a period of notice, usually around 24 hours. Customers are then charged for any consumption during the peak event at the higher critical peak price. To date, in Australia, the mechanism has only been applied at the system level in trials (ie not location specific).

Dynamic Peak Rebate (DPR) – A rebate set at a predetermined rate is applied for consumption reductions relative to a modelled benchmark during peak events. The events can be called in response to network and or wholesale market peaks with consumers given a period of notice, usually around 24 hours. The rebate is then applied to the customer's monthly bill. To date, in Australia, the mechanism has only been applied at the system level in trials (ie not location specific).

Real Time Pricing (RTP) – Customers are charged for electricity based on the short run marginal network and short run marginal generation costs which vary both by both location and over short periods of time (depending on granularity of metering technology). Real time pricing can be implemented via a range of mechanisms which vary in the extent to which the price signal is applied directly to the customer or managed on behalf of the customer by a third party

Virtual Power Plant (VPP) – A technology enabling an aggregator to control and dispatch DER at sufficient scale to access wholesale markets and major network asset deferrals and then collect and distribute payments among participating parties. The central aggregator is responsible for optimising the DER so as to deliver maximum value, a portion of which can be transferred to the customer. A VPP can operate in an environment of complex price signals (including real time pricing) acting on behalf of the customer, whilst providing the customer with a relatively simple pricing proposition.

Distribution System Platform (DSP) – A technology platform allowing one entity to optimise all DER within a distribution network in order to increase reliability and lowers costs. Can be operated by the regulated distribution network itself or handled by an independent organisation (see DSO below)

Distributed System Operator (DSO) – Acts as an independent market-operator for a diverse number of behind-the-meter participants (including VPPs) to buy and sell energy services without owning any physical assets itself. The DSO provides a market that coordinates and accurately compensates the owners of DER, or aggregators acting on their behalf, for the benefits they provide to the energy system.

3 Modelling Approach

3.1 Overview

Energeia has developed, configured and operated its Distributed Energy Resource simulation platform to model how various scenarios of network tariff reform will influence outcomes in the energy system. Energeia's DER simulation platform has been used to provide insights into the linkages between tariff reform and energy system response for a number of high profile studies.

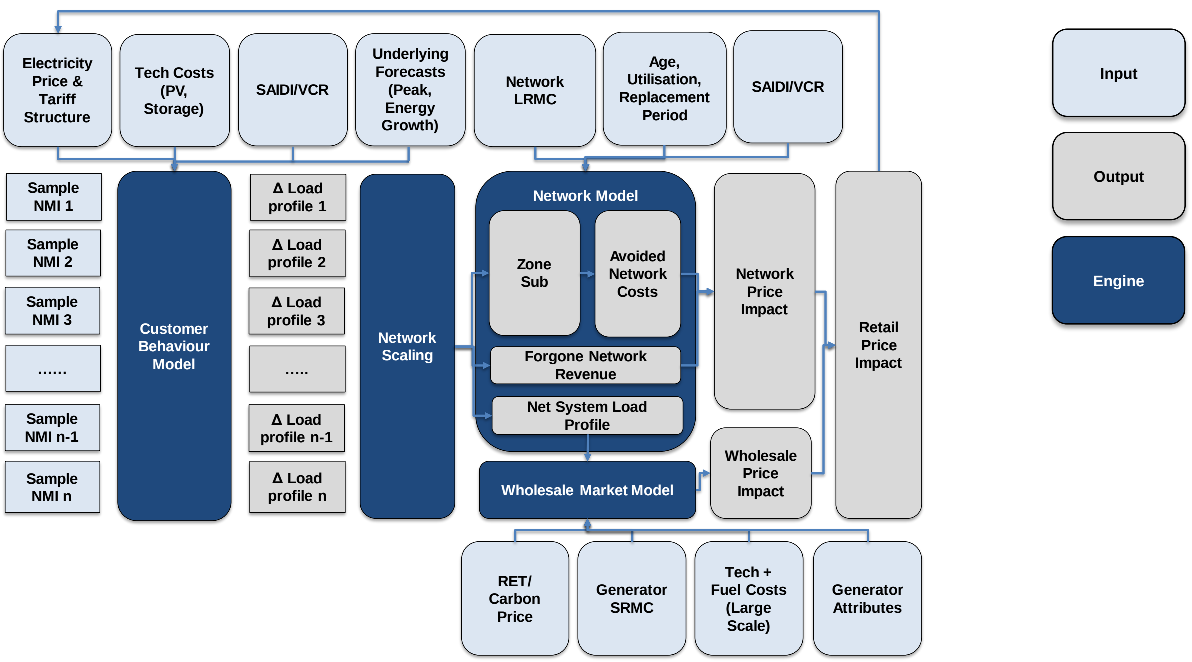
An overview of the model as applied to the study is presented below. Further detail is provided in the Technical Modelling Report.

For the purposes of this study, the modelling seeks to identify how different tariff structures and tariff assignment mechanisms:

- Incentivise the uptake and operation of distributed energy resource technology
- Influence network expenditure patterns
- Make use of investment in smart meter infrastructure
- Impact network price rises and consumer bills
- Reduce the extent of cross subsidisation between passive customers and customers who are engaged in distributed energy resource technology and demand management more broadly.
- 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

The DER simulation platform is an agent 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 network investments and wholesale markets. An overview of the model is shown in Figure 11 below.

Figure 11 – Energeia Distributed Energy Resource Simulation Platform



Source: Energeia

The model contains four key engines as discussed below. Further detail on the model and its underpinning assumptions can be found in the Technical Modelling Report.

3.1.1 Customer Behaviour Model

The model is driven by the customer behaviour model which takes a sample of 6,000 individual customer load profiles (the agents) and determines the most optimal action for each agent to take, in any given year, given the tariff and technology settings available. The customer behaviour model, then estimates the proportion of agents that adopt the most optimal solution based on their return on investment and historically observed adoption rates[32]. Those agents who adopt a new tariff and/or technology are described as active while those who make no change in either their tariff or technology (unless forced to by a network setting) are described as passive.

The customer behaviour model then determines the impact on each agent's load profile as a result of their decisions (for active agents) as well as underlying growth factors (consumption per capita, peak demand per capita) for all agents in each given year. New connections are also added as new agents each year to reflect population growth and growth in business numbers.

Customers with DER are able to adopt additional DER over time, which creates a more realistic and path dependant estimate of customer behaviour over time. For example, the simulator allows customers who adopt solar PV to adopt storage as its price falls, and customers with solar PV and storage, to go off-grid at relatively low incremental cost. The simulator also models DER end-of-life.

3.1.2 Annual Load Profile and DER Scaling

Each agent is assigned to a segment (e.g. residential, commercial, existing solar, no solar, large, medium or small) and their annual load profile and DER assets are scaled to the target population level based on this segmentation. The scaling is undertaken at both the zone substation level and system level.

3.1.3 Network Model

The network model then determines the impact of agent based customer decisions at the zone substation level. The model incorporates 1,800 zone substations Australia wide. For each zone substation, for each year, the model undertakes three sets of analyses:

1. Whether demand trends are expected to require augmenting capacity earlier than otherwise planned
2. Whether a replacement is due and, if so,
3. Whether demand trends result in a larger or smaller zone substation

The network model then determines the costs associated with any of the above investments and the associated change in Regulatory Asset Base (RAB) for each network and corresponding change in total revenue requirements for return on capital in order to set a target revenue.

The network model also calculates the total network revenue recovered from the customer base in each year and assesses any shortfall or excess in revenue compared to the target revenue (under or over recovery) and adjusts prices for the following year accordingly.

3.1.4 Wholesale Market Model

The model also analyses the impact of the changes in load patterns due to pricing and DER adoption on the wholesale market via the generation model. The wholesale market model is comprised of two parts: the plant build-out model and the plant-dispatch model[33]. The plant build-out model sets the investment in new plant and retirement of existing centralised plant that will be required to the system load profile for each year. The plant-

[32] This is known as an uptake curve. The uptake curve adopted for the purposes of this analysis was provided by CSIRO and based on historical observations of the relationship between solar PV uptake in the residential market and customer return on investment

[33] Note that the plant build out model was undertaken separately by CSIRO for a system load profile generated from a baseline model run. The dispatch model was then run separately to produce new retail prices from this plant build out. No further convergence runs were able to be undertaken within the timeframe of the modelling project.

dispatch model then determines the half hourly dispatch and corresponding spot prices for the wholesale market. The retail price for energy in each year is then set at the volume weighted average annual market clearing price.

The feed in tariff for rooftop solar PV is also set at the volume weighted average annual market clearing price during the time of solar exports. However, Energeia set a minimum floor price of 1c per kWh to reflect the strong demand response as prices approach zero, which is beyond the scope of this modelling exercise. This floor is reached in a number of states towards the later part of the modelling horizon.

3.2 Scenarios

The model was run across a series of network tariff scenarios. The scenarios were constructed to assess the relative performance of First and Second Wave network tariff and incentives structures, tariff assignment mechanisms and DER optimisation mechanisms in terms of economic efficiency and equity outcomes.

Importantly, the macroeconomic settings in the model were kept constant across scenarios and only those levers able to be pulled by networks and/or regulatory or policy makers were adjusted.

A set of six tariff, incentive and tariff policy based scenarios were developed by Energeia in close collaboration with the ENA and CSIRO. Starting from the DNSP's current network tariff structures, the scenarios were designed to vary progressively according to the timing, depth and sophistication of network pricing arrangements. The scenarios were reviewed and endorsed by an industry reference group.

The draft results of the initial six scenarios were presented in an industry stakeholder forum on July 25th 2016. Following this workshop the scenario results were finalised including updated wholesale generation costs incorporating application of a carbon price resulting in some changes to the draft results presented.

Energeia analysis of the scenarios, confirmed in feedback from the stakeholder forum, found that the structure of the tariffs as modelled were vulnerable to long-term trends in battery storage and other DER. Specifically that the structures of both the residual charges and peak signals were incentivising in efficient uptake and operation of battery storage in particular.

This led to further scenario refinement the tariff components. The insights from this refinement are themselves significant and are discussed in Section 4.

3.2.1 First Wave Scenarios

The First Wave tariff scenarios varied in terms of the tariff assignment mechanism, the structure of the residual components and the timeframe for change:

- **Scenario 1** – Represents the base case approach to network pricing arrangements whereby the current structures, peak and residual charge mechanisms and tariff assignment mechanisms, as proposed by the DNSPs in their 2016 Draft Tariff Structure Statements, are retained over the period to 2050. For the most part, this implies that customers remain on flat and or block tariffs unless they opt-in to the network proposed maximum demand tariff. Where individual networks have proposed alternative arrangements, these are also captured in Scenario 1.[34]
- **Scenario 2** – Represents the same tariff structures in Scenario 1, but with a slightly more proactive response to the existing tariff assignment and uptake policies in most jurisdictions whereby customers are assigned to maximum demand tariffs and provisioned with advanced metering for all new, altered or additional connections and any customer who adopts DER. While the tariff assignment mechanism is varied, the structure of the maximum demand tariffs as proposed by the DNSPs in their 2016 Draft Tariff Structure Statements, are retained over the period to 2050.

[34] For example: SA Power Networks has proposed that new and replacement customers as well as DER customers are placed on maximum demand tariffs from 2017 which has been adopted in the model. NSW Networks have not proposed a maximum demand tariff and instead customers are placed on their proposed declining block tariff with an option to opt-in to a volume time of use tariff over the period from 2016 to 2021. From 2021, it is assumed that Ausgrid adopts a maximum demand structure for consistency with other networks.

- **Scenario 3 –** Represents a further proactive increase in response to tariff assignment and uptake policies by networks whereby all customers are assigned to maximum demand tariffs in 2021 and provisioned with advanced metering on an opt-out basis. Again, the structures of the maximum demand tariffs remain identical those as proposed by the DNSPs in their 2016 Tariff Structure Statements over the period to 2050.

  Scenario 3 also includes an additional opt-in Stand Alone Power Supply (SAPS) tariff from 2021. This SAPS tariff is intended to act as an alternative and more attractive option for customers who may otherwise go off-grid. The tariff contains no peak charge at all and has only residual charges, which are set 5% lower than the default tariff's residual charges to encourage uptake. Customers can adopt the SAPS tariff only where they install sufficient DER and/or sufficiently modify their behaviour so as not to consume any energy at all and effectively be disconnected from the grid during peak times.

- **Scenario 3 (Adjusted)** – Has the same proactive increase in tariff 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. This scenario was run to test the impact of allocating revenue away from anytime energy volume charges on customer behaviour and economic outcomes.

  Scenario 3 (Adjusted) also includes an opt-in SAPS tariff from 2021 as per Scenario 3.

3.2.2 Second Wave Scenarios

The Second Wave scenarios included three different options for dynamic and/or locational pricing signals, available on an opt-in basis from 2021. The opt-in pricing incentives in the Second Wave scenarios were all underpinned by opt-out maximum demand tariffs as per Scenario 3, such that the incremental benefit of the opt-in Second Wave incentives can be determined by comparison with these First Wave tariff 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 offers a Critical Peak Price (CPP) from 2021 on an opt-in basis.
- **Scenario 5 –** Represents a move towards locational pricing incentives. Customers are transitioned to locational, dynamic pricing from 2021, and choose whether they operate their DER themselves, or allow the network or a third party aggregator to manage their technology for them instead.
- **Scenario 6 –** As per Scenario 5, but includes an additional level of sophistication whereby networks offer an incentive for a firm level of DER to address any shortfalls from Scenario 5. This mechanism only operates in zone substations facing an imminent investment, providing payments for up to 3 years.

Further detail on the First Wave and Second Wave scenario settings is provided in Table 3 below. Further detail on the tariff structures is provided in the Technical Modelling Report.

Table 3 – Summary of First Wave Second Wave Scenario Settings

Scenario	First Wave Tariff Type	First Wave Tariff Assignment	SAPS Tariff	Second Wave Incentive Type	Second Wave Assignment Mechanism
Scenario 1	Demand Based Tariff as per Draft TSSs	Opt-in	None	None	NA
Scenario 2	Demand Based Tariff as per Draft TSSs	Opt-out for New, Replacement, and Mandatory for New and Additional DER from 2021	None	None	NA
Scenario 3	Demand Based Tariff as per Draft TSSs	Opt-out from 2021	Opt-in from 2021	None	NA
Scenario 3 (Adjusted)	Demand Based with Reduced Residual Volume Component	Opt-out from 2021	Opt-in from 2021	None	NA
Scenario 4	Demand Based Tariff as per Draft TSSs	Opt-out from 2021	Opt-in from 2021	Critical Peak Price (System Level)	Opt-in from 2021
Scenario 5	Demand Based Tariff as per Draft TSSs	Opt-out from 2021	Opt-in from 2021	Incentive in exchange for operational access and periodic use of existing DER	Opt-in from 2021
Scenario 6	Demand Based Tariff as per Draft TSSs	Opt-out from 2021	Opt-in from 2021	Incentive in exchange for operational access and periodic use of existing *and* new DER	Opt-in from 2021

4 Summary of Results

The results below present the findings of Energeia's modelling at the NEM level. Results for individual states are provided separately in the technical modelling report.

The results are presented as followed for each scenario over the period to 2050

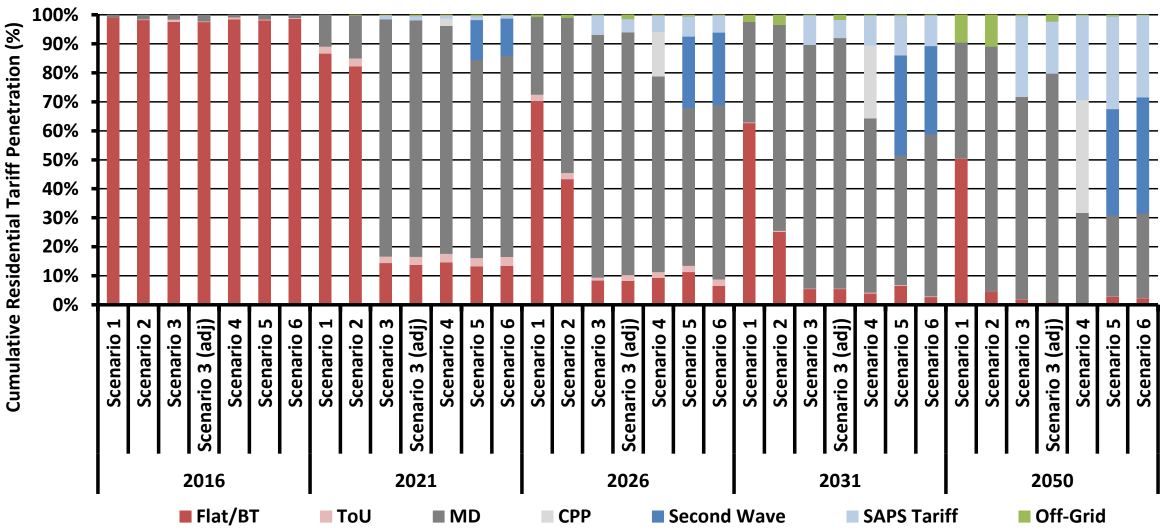
1. **Tariff and Technology Uptake** – Compares the uptake of cost reflective tariffs by tariff type and DER technology
2. **Smart Meter Uptake** – Compares the uptake of cost reflective tariffs to the number of smart meters deployed to assess the difference in smart meter utilisation between scenarios
3. **Energy Consumption** – Compares the total annual energy consumption for each scenario over time
4. **Peak Demand (ZS Non-Coincident)** – Compares the non-coincident change in peak demand at the zone substation level (driver of network costs) for each scenario over time
5. **Network Investment** – Compares the investment required in network capacity at the zone substation level for each scenario over time
6. **Network Pricing Impact** – Compares the change in network revenue requirements and the corresponding change in average network prices for each scenario over time
7. **Centralised Generation Requirements** – Compares the investment required in centralised generation between scenarios
8. **Wholesale Pricing Impacts** – Compares the change in wholesale prices between scenarios
9. **Greenhouse Gas Benefits** – Compares the greenhouse gas emissions and emission intensity between scenarios
10. **Economic Benefits** – Compares the economic benefits of each scenario to the base case over the period to 2050
11. **Bill Impacts** – Compares the impact on average bills as well as cross subsidies and provides case studies of nominated "cluster leads"

4.1 Tariff and Technology Uptake

4.1.1 Residential Sector

Figure 12 below shows the actions taken by residential customers over time to adopt new tariffs under each scenario. An action to change tariff can either be driven by the bill savings opportunities or as a result of a tariff assignment mechanism.

Figure 12 – Cumulative Tariff Uptake (Residential)



The results show that between 2016 and 2021 in Scenario 1 there is around 13% uptake of maximum demand tariffs or time of use tariffs under an opt-in basis, in Scenario 2 this increases to 18% as a result of the tariff assignment mechanism for new and replacement meters. In Scenario 3, customers are assigned to maximum demand tariffs in 2021 such that 84% of the residential population transfers to either a maximum demand or time of use tariff with 14% of customers opting out and 1% of customers choosing to go onto the SAPS tariff. Similar results are seen in Scenario 3 (Adjusted).

By 2026, Scenario 1 opt-in has increased uptake of maximum demand tariffs to 27% with 70% still remaining on legacy tariffs. Whilst under Scenario 2 and 3, legacy tariffs have declined to 43% and 8% of residential customers respectively.

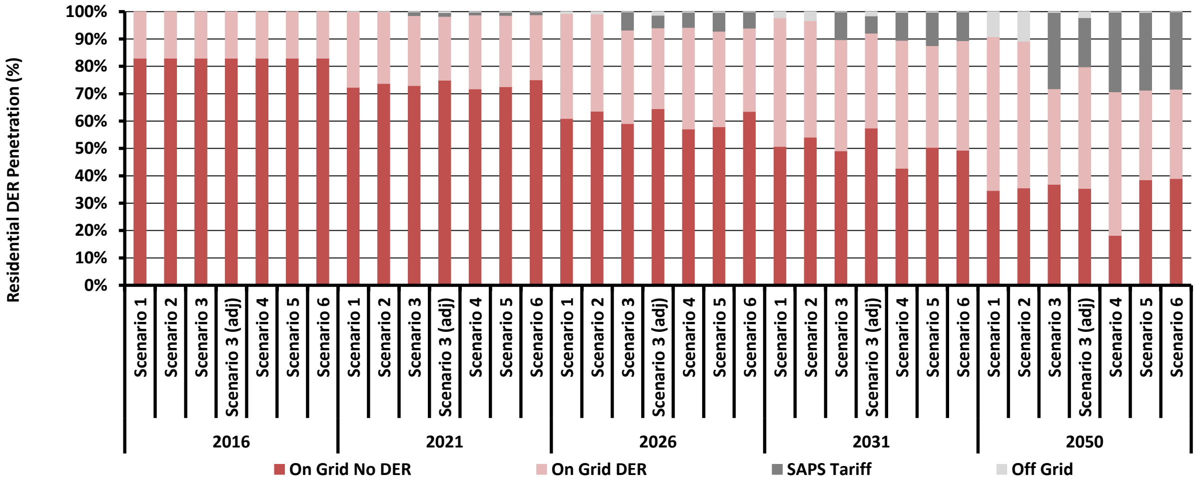
In 2026, optional uptake of the Second Wave incentives begins to take hold with 15% of customers having opted in to the CPP tariff under Scenario 4 and 28% and 29% of customers taking up the incentives offered under Scenario 5 and 6 in exchange for operational access and periodic use of DER. By 2026, uptake of the SAPS Tariff also becomes significant under all scenarios (where it is offered under Scenario 3 to 6) at between 5% and 7% of customers, however it reduces complete grid defection to negligible levels.

Over the next two decades to 2050, customers under Scenario 1 continue to opt-in slowly to the maximum demand tariff with 50% of residential customers remaining on legacy tariffs by the end of the period. Under Scenario 2, only 5% remain as the new, replacement and DER tariff assignment mechanism has finally captured the majority of customers. Scenario 3 and Scenario 3 (Adjusted) are dominated by maximum demand tariffs but an increasing number of customers have taken advantage of the SAPS tariff.

Overall, these results suggest that an opt-in approach to First Wave tariffs is unlikely to drive mass tariff migration. The new, replacement and DER tariff assignment mechanism can drive mass tariff migration but this is slow and will take several decades to achieve critical mass. The opt-out framework drives fast transition and then facilitates transition to the Second Wave incentives in later years.

Figure 13 below shows the corresponding number of residential customers adopting DER whereby DER adoption is driven by the financial return on investment.

Figure 13 – Cumulative Technology Uptake (Residential)



Between 2016 and 2021, the number of DER customers increases across all scenarios from around 17% to 27% of customers with differences between scenarios in 2021 marginal due only to activity in that year.

Then, in 2026, differences in DER uptake begin to emerge across scenarios. In Scenario 2, there is a requirement for new DER customers to transfer to a maximum demand tariff. This reduces DER uptake in this scenario in 2026, as the cross subsidies to DER customers on volume based legacy tariffs are no longer available. Under Scenario 3, the same restrictions apply, but increased DER is taken up to enable transition to the SAPS tariff (available in Scenario 3 to 6). Scenario 3 (Adjusted) reduces DER uptake in 2026 compared to Scenario 3 due to the reduction in the volume based rate of this tariff reducing the incentive for solar. DER penetration under the opt-in CPP in Scenario 4 starts to increase as the strong peak signal of this tariff, coupled with declining technology costs improves the attractiveness of battery storage. These factors are also observable for Scenario 5 and 6 but to a smaller extent.

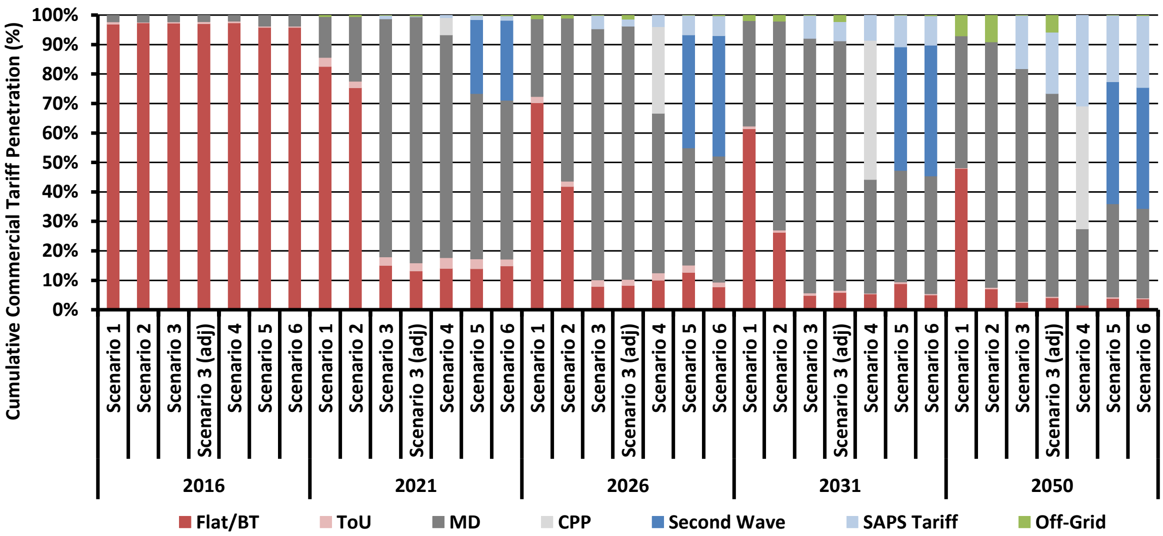
Towards 2050, the level of DER penetration begins to converge across all scenarios to between 61% and 69%, with the exception of Scenario 4. In Scenario 4, the CPP tariff incentivises uptake of battery storage to reduce demand during peak events. However, charging of the batteries in readiness for peak events occurs as soon as consumers receive the 24 hour notification, which, once battery storage penetration is sufficiently high, creates a new peak, and in turn strengthens the peak signal, incentivising even more storage uptake. By 2050, uptake of DER under either the CPP or SAPS tariff reaches 82% of the population.

Overall, these results show that DER penetration will be high regardless of the tariff setting due to the decline in technology prices as well as the prevailing retail tariff which increases over time driven by a carbon price. The results for Scenario 4 suggest that tariffs that do not adequately consider battery charging impacts have the potential to create new peaks, driving stronger peak signals and thus leading to very high levels of battery penetration. It is likely that such a tariff scenario would be made quickly obsolete as these outcomes start to appear and that the 2050 result is therefore unlikely.

4.1.2 Commercial Sector

Figure 14 below shows the actions taken by commercial customers over time to adopt new tariffs for each scenario.

Figure 14 – Cumulative Tariff Uptake (Commercial)



Between 2016 and 2021 in Scenario 1 there is around 17% uptake of maximum demand tariffs or time of use tariffs on an opt-in basis for commercial customers. In Scenario 2 this increases to 24% as a result of the tariff assignment mechanism for new and replacement meters. This is slightly greater than the numbers observed in the residential sector, indicating these tariffs are more attractive to commercial customers in the first instance. In Scenario 3, as with the residential sector, all customers are all switched over to maximum demand tariffs in 2021.

By 2026, opt-in under Scenario 1 has increased uptake of maximum demand tariffs to 26% of commercial customers with 70% still remaining on legacy tariffs. Whilst under Scenario 2 and 3 respectively, legacy tariffs have declined to 42% and 8% of commercial customers respectively. By this time, these numbers are very similar to the residential sector.

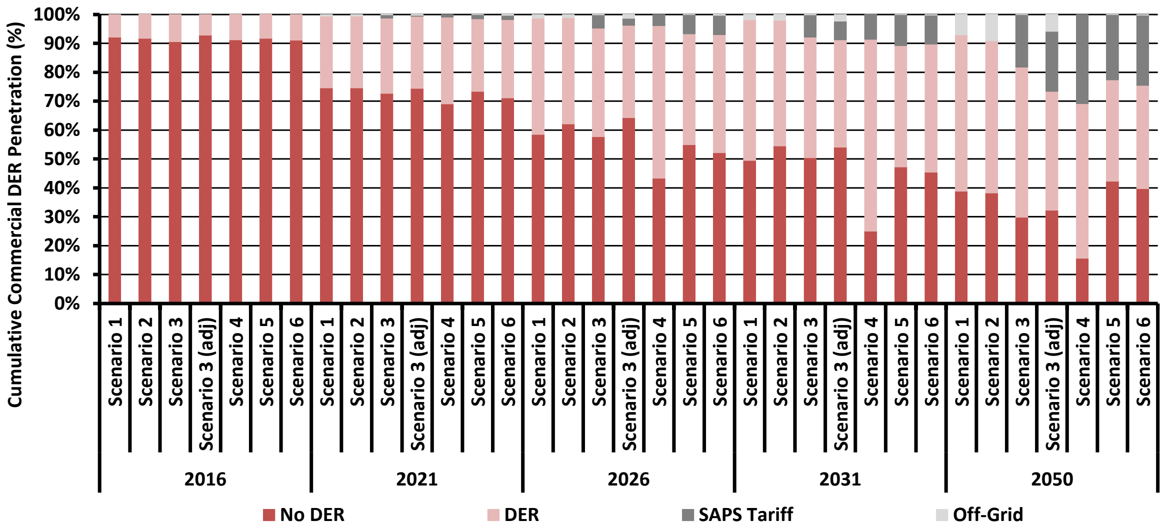
In 2026, optional uptake of Second Wave incentives become very popular with 29% of commercial customers having opted in to the CPP tariff under Scenario 4 and 38% and 41% of customers taking up the incentives offered under Scenario 5 and 6 in exchange for operational access and periodic use of DER, significantly greater than the uptake observed in the residential sector. By 2026, uptake of the SAPS tariff also becomes significant at between 2% and 7% of commercial customers under the scenarios it is available, similar to the residential sector. Complete grid defection is also reduced to negligible amounts.

Over the next two decades to 2050, under Scenario 1 customers continue to opt-in slowly to the maximum demand tariff with 48% of customers remaining on legacy tariffs by the end of the period. Under Scenario 2, only 7% remain. Scenario 3 and Scenario 3 (Adjusted) are dominated by maximum demand tariffs but an increasing number of customers have taken advantage of the SAPs tariff.

Overall, these results suggest that in terms of driving mass churn, the opt-in approach to First Wave tariffs is no more effective in the commercial sector than the residential and is unlikely to drive mass tariff churn.

Figure 15 below shows the corresponding number of commercial customers adopting DER driven by the financial return on investment.

Figure 15 – Cumulative Technology Uptake (Commercial)



Between 2016 and 2021, the number of customers adopting DER in the commercial sector increases across all scenarios from around 9% to 25% of customers. The one exception to this is Scenario 4 where DER penetration reaches almost 30% by 2021.

In 2026, similar results are observed as for the residential sector, whereby Scenario 2 has relatively low DER uptake due to the withdrawal of volume based cross subsidies for new DER customers. Scenario 3 DER uptake relative to Scenario 1 is driven by the attractiveness of the SAPS Tariff. As with the residential sector, Scenario 3 (Adjusted) also reduces DER uptake in 2026 relative to Scenario 3, without the change to the residual charge.

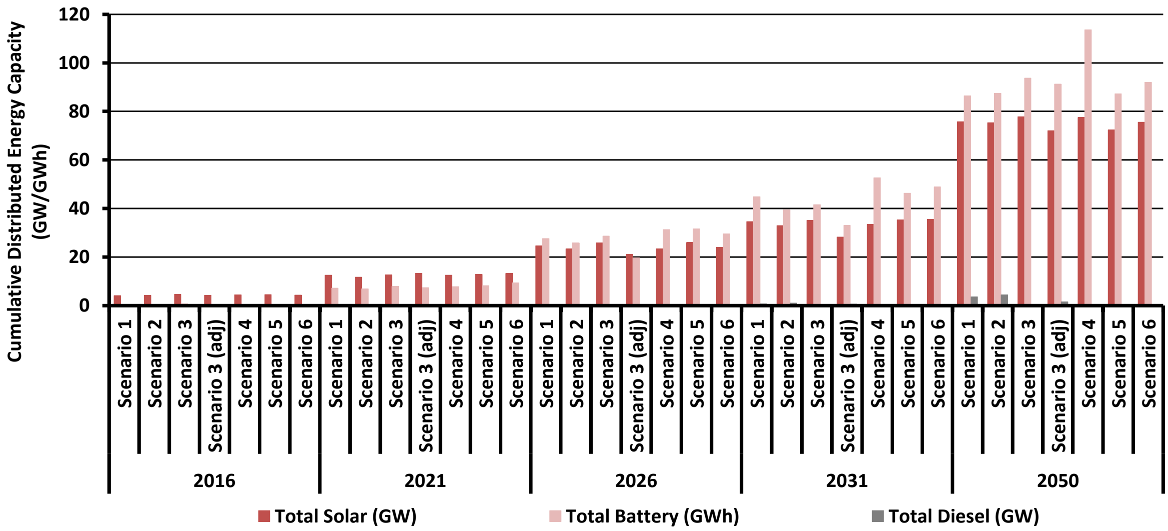
By 2050, the level of DER penetration across all scenarios, with the exception of Scenario 4, is between 58% and 70%. In Scenario 4, the CPP tariff incentivises uptake of battery storage to reduce demand during peak events. However, charging of the batteries in readiness for peak events occurs as soon as consumers receive the 24 hour notification, which, once battery storage penetration is sufficiently high, creates a new peak, which in turn strengthens the peak signal, incentivising even more storage uptake. The same effect is observed in any adoption of the SAPS tariff such that, by 2050, uptake of DER under either the CPP or SAPS tariff reaches 84% of the population.

Overall, these results are consistent with the residential sector, showing that DER penetration will be high regardless of the tariff setting as tariff structures that do not adequately consider battery charging impacts have the potential to create new peaks, driving stronger peak signals and leading to very high levels of battery penetration.

4.1.3 Total DER Uptake

Figure 16 shows the total DER technology uptake over time for each scenario in terms of cumulative solar and storage capacity. Diesel capacity is also shown, available to customers seeking to go off-grid in non-urban areas.

Figure 16 – Cumulative Technology Uptake (Commercial and Residential)



Between 2016 and 2021 the results of the modelling show significant uptake of solar PV with an approximate tripling of installed capacity across all scenarios to reach in excess of 16GW. Battery storage uptake over the same time frame reaches between 7GWh to 9GWh with adoption concentrated towards the latter part of the period. The main drivers for storage uptake over this time are relatively high solar shifting benefits offered by the retail component of the tariff in all scenarios.

By 2026, differences between scenarios emerge. Scenario 3 (Adjusted) results in the least capacity, with 21GW of solar PV and 20 GWh of battery storage, due to a reduced incentive for solar shifting via a reduction in the volume component of the network tariff. By 2026, the CPP tariff in Scenario 4 has encouraged 22% more battery storage than the base case due to the large value able to be derived from battery storage during peak events.

Over the period between 2026 and 2031, the scenarios underpinned by strong maximum demand uptake (Scenario 3, 5 and 6) start to encourage large storage uptake, reaching between 42GWh and 49GWh across the NEM by 2031. This large uptake is sufficient to create new peaks in some parts of the network whereby all customers on maximum demand charge their batteries as soon as the off peak period commences without any tariff penalty. The creation of new peaks creates a feedback loop, which leads to an increase in the peak signal, encouraging further storage uptake, similar to what is seen under the CPP tariff in earlier years. Scenario 3 (Adjusted) remains the most effective at minimising inefficient battery storage adoption and avoiding this impact for longer, but by 2050 is no more effective than any other maximum demand tariff.

Scenarios 5 and 6 also encourage large amounts of DER due to the underpinning maximum demand tariff, however under these tariffs, a large proportion of the storage is controlled (by the network directly or a third party in response to real time price signals) such that new peaks can be avoided and feedback to the peak signal is minimised.

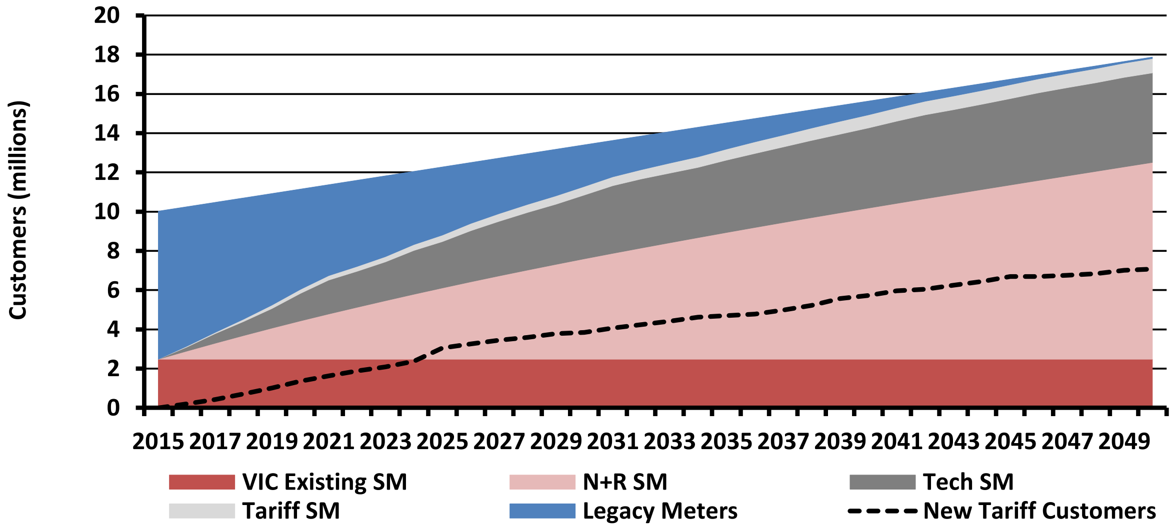
Overall, the results for DER uptake indicate that solar PV uptake will dominate the NEM over the next 35 years reaching between 65GW and 78GW in 2050, driven by strong volume signals in the retail tariff especially where these incorporate a high carbon price. Battery storage is also likely to be taken up as a complementary technology to solar, enabling shifting of solar exports. With such large volumes of storage, the peak signals within the network tariff become increasingly utilised for discharge, with charging during the off peak.

4.2 Smart Meter Uptake

The following charts (Figure 17 to Figure 19) show Energeia's forecasts for smart meter uptake over the period to 2050 and the corresponding uptake of either First Wave tariffs or Second Wave incentives (i.e. those tariffs and incentives that require interval metering). Smart meter uptake is a function of both the existing policy framework for smart meters in a jurisdiction and the scenario impact on smart meter uptake in the future.

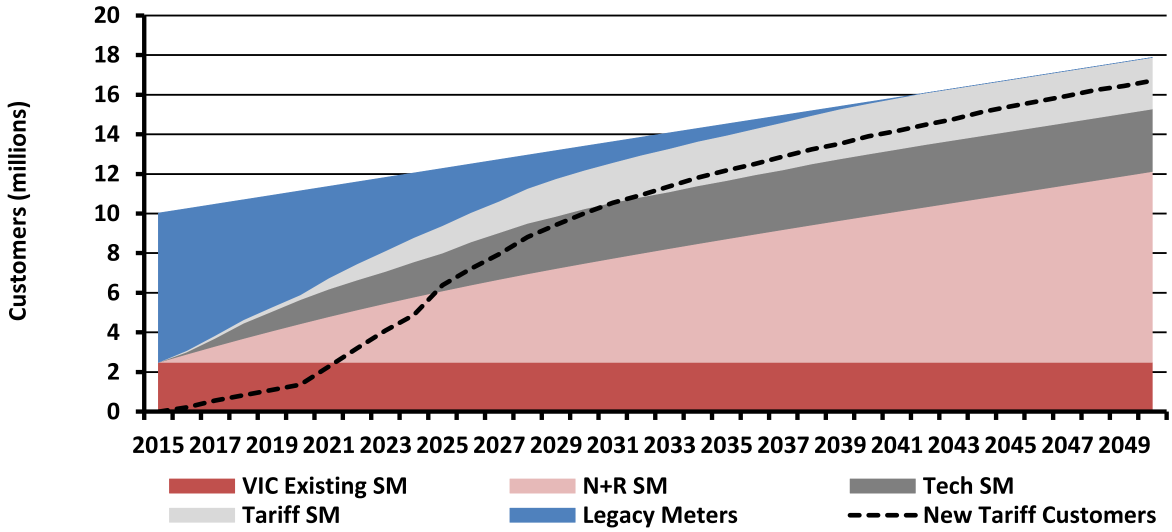
Only Victoria has near full saturation of smart meters. The transition to more smart meters in other states will be subject to recent rule changes outlined below.

Figure 17 – Cost Reflective Tariff Uptake Compared to Smart Meter Uptake (Scenario 1)



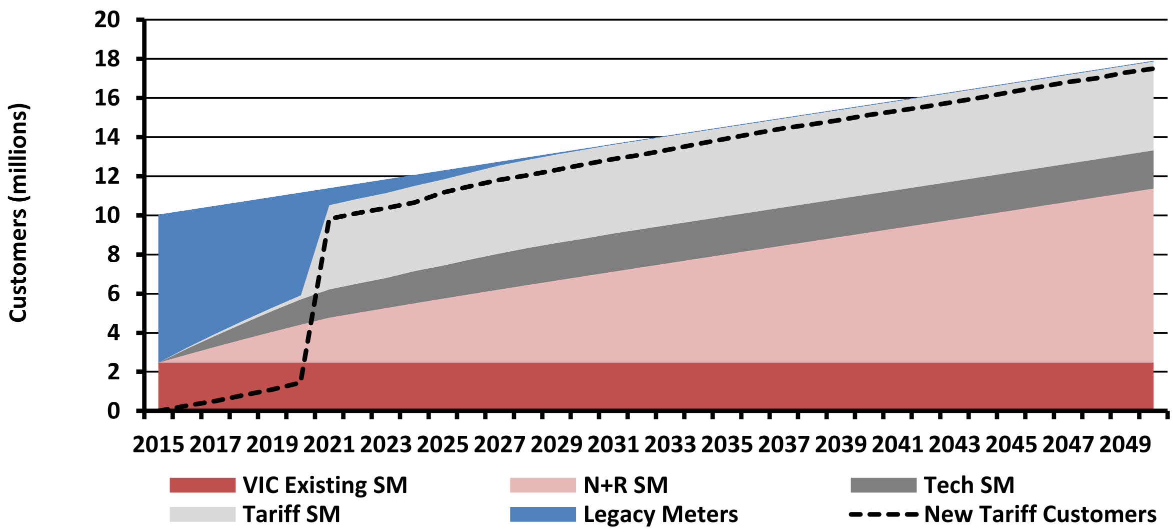
Under Scenario 1, uptake of smart meters is driven by the requirement for all new and replacement meters (including replacement with the uptake of DER technology) to incorporate smart metering technology under constestable arrangements. By 2050 almost all customers have transitioned to a smart meter. However, the drivers for First Wave tariffs and Second Wave incentives uptake are relatively weak such that by 2050 only 40% of smart meter investment is utilised for the purposes of tariff reform, implying up to $2.7B in smart meter investment is underutilised.

Figure 18 – Cost Reflective Tariff Uptake Compared to Smart Meter Uptake (Scenario 2)



Under Scenario 2, uptake of smart meters is driven by the same contestability in metering requirements plus an additional tariff churn for move in/move out customers assumed as a tariff assignment mechanism in this scenario. Under this scenario, almost all customers have transitioned to a smart meter by around 2040.

Figure 19 –Cost Reflective Tariff Uptake Compared to Smart Meter Uptake (Scenario 3,4,5,6)



The drivers for First Wave tariff and Second Wave incentive uptake are stronger than Scenario 1 and much more aligned to the competition in metering requirements, whereby new and replacement customers are assigned both a smart meter and a First Wave tariff. Under Scenario 2, by 2050 only 93% of smart meter investment is utilised for the purposes of tariff reform, implying only $300M in smart meter investment is underutilised by this time.

Under Scenario 3 to 6, uptake of smart meters is the same driven by the same contestability in metering requirements plus a mass tariff migration in 2021 delivering almost 100% smart meter penetration and full utilisation of smart meter investment at this time (except for smart meter/tariff opt-out customers).

Overall, the smart meter results suggest significant underutilisation of smart meter investment under the base case which can be remedied by tariff assignment mechanisms aligned to the new and replacement smart meter driver under the competition in metering framework.

There are a range of policy and logistical challenges to the realisation of the smart meter deployment modelled under Scenario 3 to 6. The modelling assumes deployment of around 4.3 million advanced meters, at an approximate cost of $1.1B[35], can occur in conjunction with the mass tariff assignment in 2021.

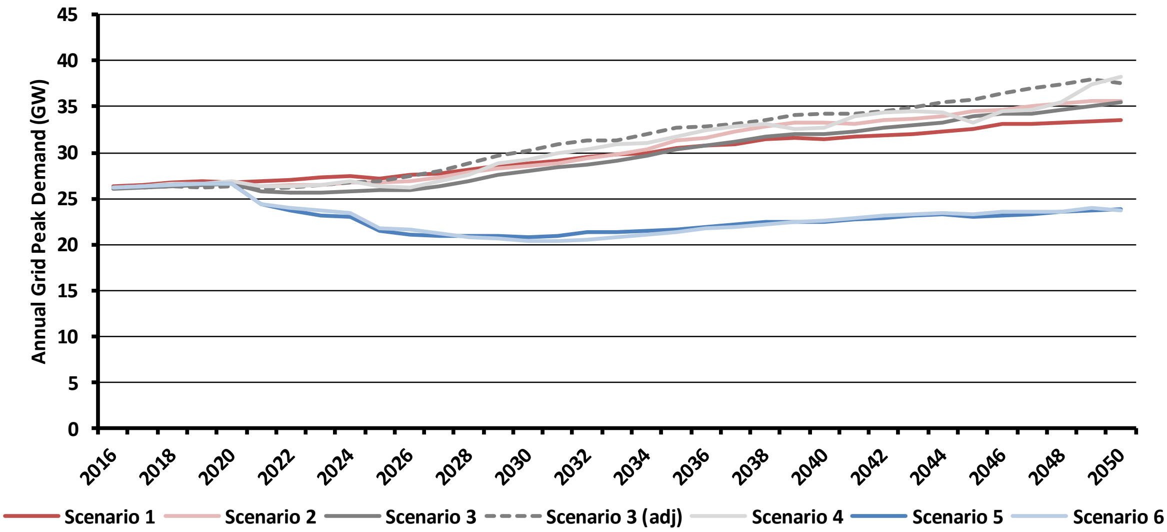
The need for such a rapid deployment would be avoided if market led metering deployments are successful in achieving significant meter deployment before 2021. However, should it fail to eventuate by further meter deployment would be rapidly required at scale to secure the potential benefits available to customers from these scenarios.

4.3 Network Peak Demand

The modelling is driven by costs at the network zone substation level which are influenced by localised peak demand. In practice, there is often little correlation between local and system peak demand. Figure 20 shows the change in non-coincident zone substation peak demand over time for each scenario which represented the sum of individual peak demand at each zone substation modelled (and therefore can be expected to exceed system demand).

[35] Assuming $250 for meter and installation costs

Figure 20 – Non-Coincident ZS Peak Demand



In the years between 2021 and 2026, the First Wave scenarios underpinned by opt-out tariff assignment mechanisms for maximum demand tariffs reduce non-coincident peak demand compared to the base case due to the tariff signals incentivising reduced consumption in the peak period. The relative performance of Scenario 3 and Scenario 3 (Adjusted) over this period is similar at the NEM. However, Energeia observed clear differences between state-based results. In states with relatively high prices (e.g South Australia), the adjustment to the volume component in Scenario 3 (Adjusted) tended to encourage more customers onto the SAPS tariff (due to the increased fixed charge) rather than encourage reduced battery storage uptake. However, in states with relatively low prices (e.g NSW), the mechanism was more effective in reducing battery storage uptake without encouraging SAPS tariff uptake.

From 2026, the effectiveness of the maximum demand tariffs in managing network peak demand, begins to erode as storage uptake reaches critical mass, and off peak charging of storage without sufficient diversity, starts to lead to new peaks. This effect is observed in all scenarios, but mostly in Scenario 4, due to the particularly strong signals to all customers to charge prior to peak events. The effect is also observed in Scenario 3 (Adjusted) due to the number of customers incentivised onto the SAPS tariff which have the same weakness as the CPP tariff of undiversified charging prior to peak events.

Scenarios 5 and 6, however, presented a very different outcome. As soon as these tariffs are made available in 2021, the incentive is attractive to customers and any battery storage installed is able to be accessed periodically in order to optimise utilisation by co-ordinated discharge and avoid any new peaks by co-ordinated charging.

There is very little difference observed between Scenario 5 and 6 over the entire period. Although Scenario 6 allows uptake of new storage in optimal locations, this option is seldom selected by the model due to both a lack of constraints in the early years and then an oversupply of battery storage (driven by underpinning maximum demand tariff) in later years, implying existing storage can be used to manage new peaks rather than installation of additional units.

Overall, these results reveal the inefficiencies in First Wave tariffs compared to what would otherwise be achievable through coordination of battery storage under Second Wave incentives. Further, the results indicate, that First Wave tariffs are effective over the period to 2016 to 2026 in reducing network peak demand relative to the base case, with an inflection point occurring around 2026.

4.3.1 Capacity

The non-coincident zone substation peak changes as shown in Figure 20, lead to changes in requirements for zone substation capacity as shown in Figure 21 in terms of total capacity and in Figure 22 in terms of capacity by investment driver. The performance of each of the scenarios relative to the base case depends on the extent to which it can eliminate early augmentation drivers and give rise to smaller replacements rather than larger or equal sized replacements, thus driving down network costs.

Figure 21 – Total ZS Capacity Requirements

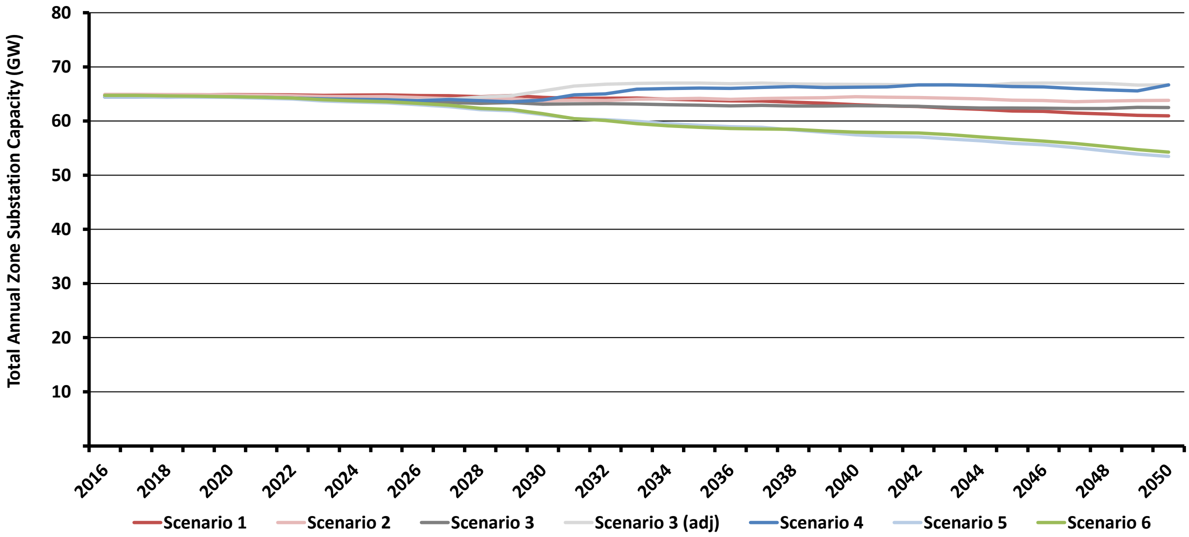
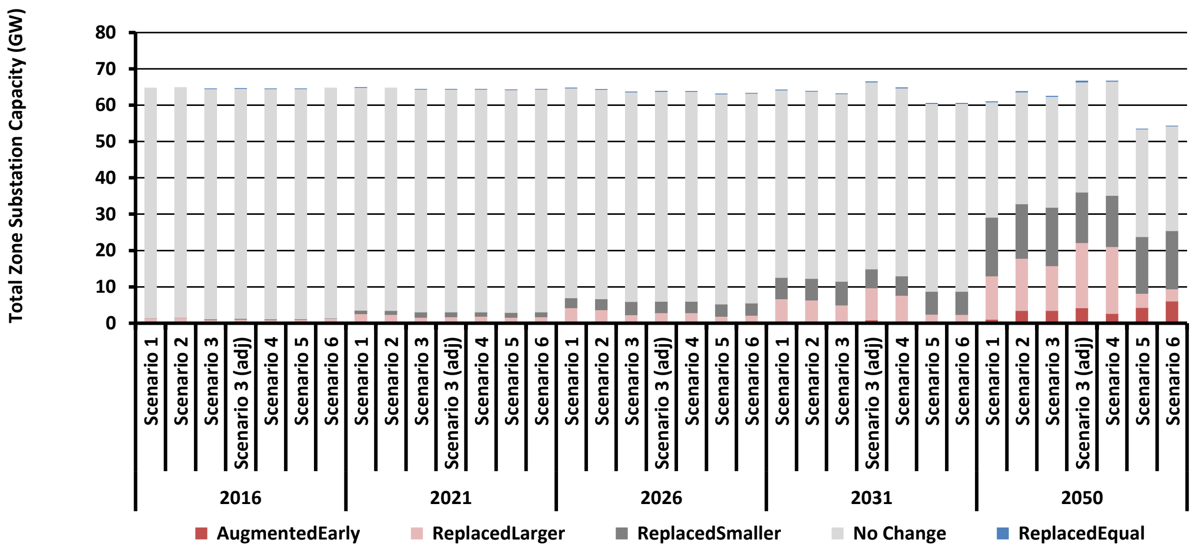


Figure 22 – Total ZS Capacity Requirements by Investment Driver



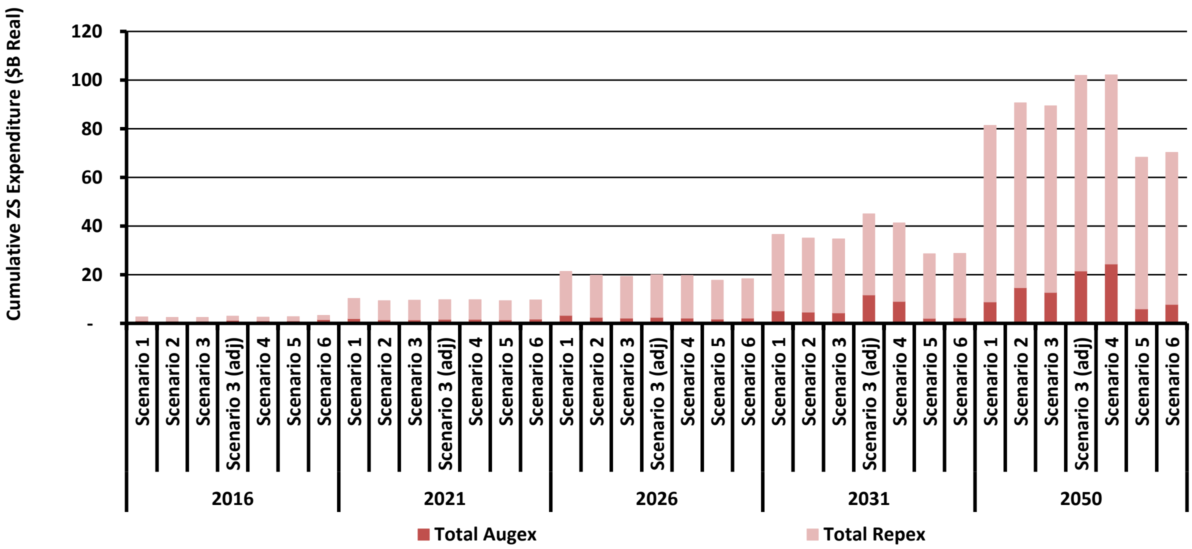
Between 2016 and 2021, there are relatively few drivers for investment. From 2021, some replacement drivers emerge. To 2026, Scenario 3, Scenario 3 (Adjusted) and to a lesser extent Scenario 2, are able to reduce the number of larger replacements modelled in the base case.

However, from 2026, the opt-out maximum demand scenarios, Scenario 3 and Scenario 3 (Adjusted), as well as Scenario 4 begin to drive increased zone substation capacity and a requirement for larger replacements. Whilst over the period from 2026 to 2050, Scenario 5 and 6 are able to reduce the need for larger replacements as the network zone substation capacity declines.

To 2050, Scenario 2 to Scenario 4 all result in early augmentations due to the new peaks created by unmitigated off peak charging of battery storage, particularly under the CPP tariff and the SAPS tariff. Although less total capacity is required under Scenario 5 and 6 compared to all other scenarios, they do drive the greatest early augmentation. This effect is due to the replacement with smaller capacity occurring in 2031 without the model able to foresee the increased capacity that occurs in these scenarios from 2031 (i.e. the model, like network planners, does not have perfect foresight).

The resulting total expenditure requirements in zone substation capacity as a result of the investment drivers discussed above is shown in Figure 23.

Figure 23 – Expenditure on ZS Capacity Requirements



Overall investment in zone substation capacity to 2021 under the base case is $21B, 82% of which is driven by replacement. An opt-out tariff assignment mechanism, under Scenario 3 and Scenario 3 (Adjusted) is able to reduce this to $19B, deferring augmentation and replacing smaller.

However, to 2031 and beyond, the new peaks created by battery storage charging during the off peak period increase investment in zone substation capacity, such that by 2050, Scenario 2, 3, 3 (Adjusted) and Scenario 4 all require greater investment that the base case.

Notwithstanding, the Second Wave incentives in Scenario 5 and 6, drive down network costs from their very first year of implementation and offset any impacts created by remaining First Wave tariffs.

These results suggest that the First Wave tariffs can effectively reduce network costs compared to the base case to around 2026. From this point, careful consideration needs to be given to the structure of the tariffs in terms of both the peak signal and residual signal to avoid over incentivising battery storage as well as mitigation of off peak charging impacts.

4.4 Network Pricing Impact

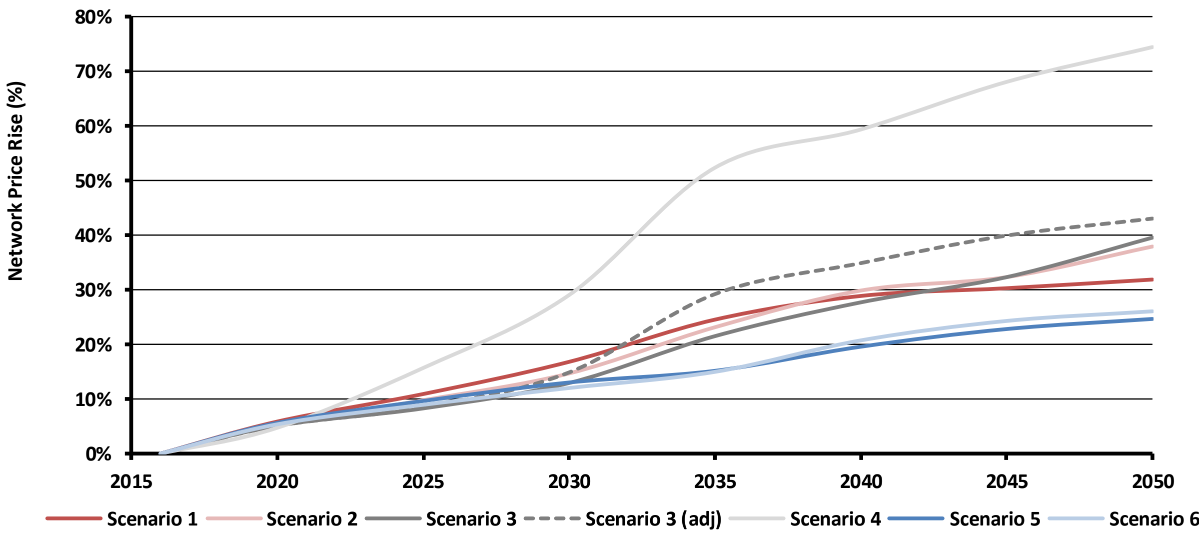
The impact of DER uptake on network prices is driven by two factors. Firstly the extent of network investment required to accommodate changes in peak demand and secondly the amount of revenue bypassed by the customers taking up DER. Where the latter is greater than the former then network price rises will occur.

Figure 24 below shows this network price rise in terms of the average change in each component of the network charge that needs to occur in order to ensure that each network recovers their required revenue. Note, this does not infer that network's revenue requirements increase on a year on year basis, and in fact, in some years, network revenue decreases. However, as the chargeable quantities decrease, then network price rises occur. In the modelling, the network price impact is concentrated on the residual charges and the peak price impact only increases in a cost reflective manner (i.e. where there is an increase in peak demand).

It should also be noted that increasing network *prices* may not necessarily equate to increasing network bills. As demonstrated in Section 4.8.1 below, average annual network bills for customers are generally *lower* rather than higher in both 2026 and 2050 compared to 2016 with effective, timely tariff reform. However, for completely passive customers, who do not adopt technology and do not improve their energy efficiency over time, the network component of their bill would be expected to increase in line with the results below.

Note that networks are unlikely to apply these price rises on an annual basis. At the start of each regulatory period, networks will forecast both their revenue requirements and demand and set prices accordingly, smoothed over a five year period. Further, changes in network prices will be subject to factors outside of the scope of the modelling. The modelling considers revenue requirements associated with zone substation capacity investments only, other factors such as improvement in operational efficiencies will also impact network prices.

Figure 24 – Network Price Impact



Over the period between 2016 to 2021 network prices are modelled to rise due mostly to solar uptake and corresponding under-recovery by networks[36].

From 2021 to 2026, the First Wave tariffs under an opt-out assignment mechanism (Scenario 2, 3 and 3 Adjusted) are able to reduce the network price rises by both reducing network investment and reducing network bypass from solar PV. The CPP tariff under Scenario 4 immediately begins to cause price rises as a result of both avoided revenue from battery storage and behaviour change effects at the system peak which do little to reduce peak demand at the zone substation level and thus avoid costs.

From 2026, the performance of maximum demand tariffs begins to erode as a result of increased network costs via the creation of new peaks from storage. The structure of the maximum demand tariff influences how quickly these effects begin to emerge and vary by network.

Over the period from 2031 to 2050, the First Wave tariffs as modelled are no longer delivering benefits and there is a need for Second Wave reform to mitigate the impacts of high penetration of battery storage and lack of diversity in off peak charging.

4.5 Centralised Generation Requirements

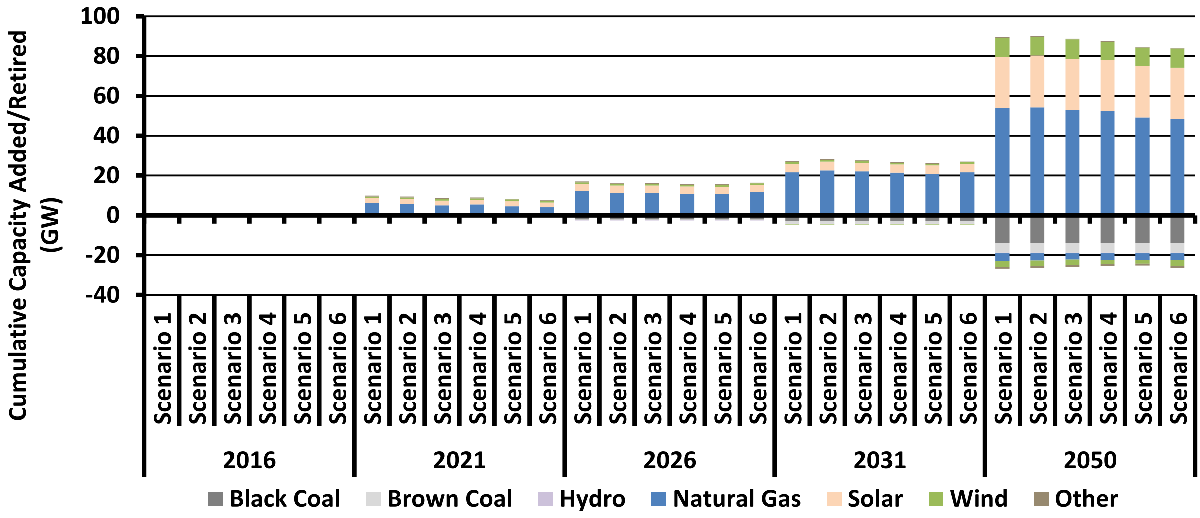
The following section describes the change in centralised generation requirements over time in response to the increase in decentralised generation. Note that the wholesale market model was not run for the Scenario 3 (Adjusted). This scenario adopts the same centralised generation assumptions as Scenario 3.

4.5.1 Capacity

Figure 25 shows the total investment requirements in centralised generation over the period to 2050 driven by the Renewable Energy Target, the carbon price as well as the change in system load profile as a result of DER.

[36] Note, forecasts of solar PV and revenue requirements have already been prepared for networks for this period and prices set accordingly. For many networks, while these factors are real, the increase in network prices, as modelled, was not observed due to factors outside of the modelling scope (such as improvements in operational efficiency etc).

Figure 25 – Centralised Generation Capacity



Over the period to 2021 there is no material investment in the centralised generation sector under any scenario.

By 2026, there is a requirement for additional natural gas in order to provide for increases in load outside of solar times. This is highest for Scenario 1 at 6.1 GW and lowest for Scenario 6 at 4.0 GW due to the reduced demand delivered under operational access and periodic use by networks of battery storage in Scenario 6. An additional 3.0 GW to 3.4 GW (depending on the scenario chosen) of renewable energy is added by 2026 in the form of solar and wind..

From 2026 to 2031, a total of 4.2 GW of capacity of black and brown coal plants has been retired, consistent across all scenarios, reflecting a reduction in the need for base load generation due to very low and negative spot prices during the middle of the day. Scenario 4 does a relatively good job in limiting new capacity (2% less than the base case) due to the CPP tariff peak signal aligning with system peak, the driver of centralised generation investment.

By 2050, total new investment has reached between 90GW to 82GW in Scenario 1 and in Scenario 6.

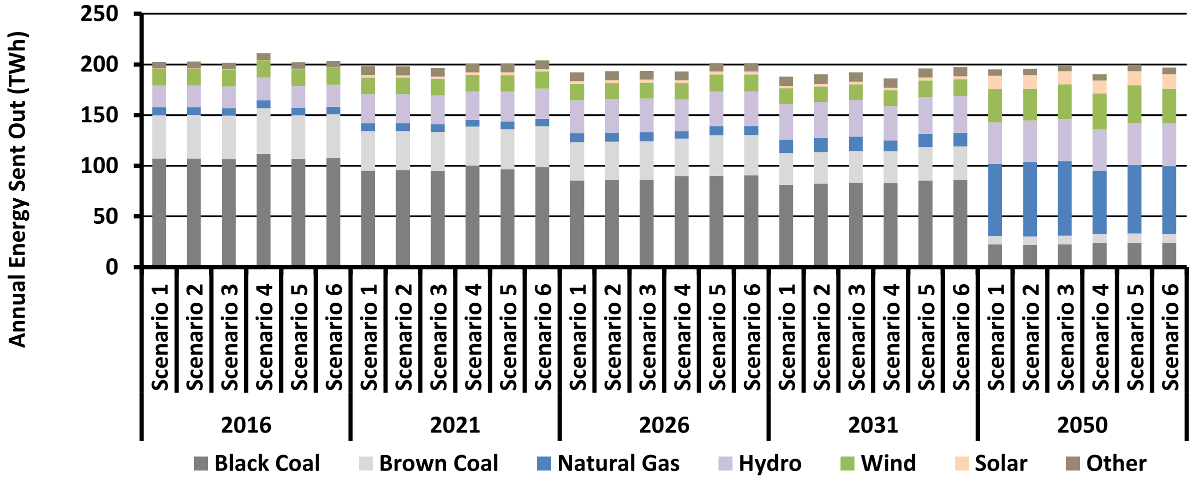
Overall, the results indicate that investment in centralised generation is materially impacted by the tariff scenarios but follows the same trends of increased solar and wind, in response to strong carbon pricing and increase in natural gas capacity to provide for increased demand outside of solar times.

4.5.2 Energy Sent Out

Figure 26 shows the total energy sent out across the NEM from existing capacity and new capacity as modelled above.[37]

[37] Note that the modelling of hydro generation assumes that the generation is limited by plant capacity rather than water inflows into dams (ie the model assumes infinite stored water available). Where this is not the case then it is likely that natural gas generation would provide the additional volume or alternatively new pumped hydro or grid-scale batteries.

Figure 26 – Centralised Generation Energy Sent Out (Scenario 1)



The results show relatively consistent centralised energy generation across all scenarios and over time. Natural gas generation increases over time displacing generation by baseload coal. This effect is most pronounced towards the latter part of the modelling period as the diurnal pattern in demand begins to emerge (in 2050, there is a net negative demand during the middle of the day on the average day).

Solar generation is relatively low compared to its capacity as a large portion is spilled during the middle of the day as renewables on renewables competition between the centralised and decentralised markets emerge.

Overall, these results reflect a highly volatile centralised generation environment driven by diurnal patterns in customer load. There is very little variation between scenarios, with the exception of Scenario 4 which results in slightly less generation than the base case by the end of the modelling period due to the tariff signal directed at system peak demand.

4.5.3 Wholesale Market Prices

Figure 27 to Figure 32 show the change in annual volume weighted average (VWA) prices for each scenario. These prices are then applied in the model as a flat volume charge within the retail component of the bill.

Figure 27 – Wholesale Market Volume Weighted Average Prices (Scenario 1)

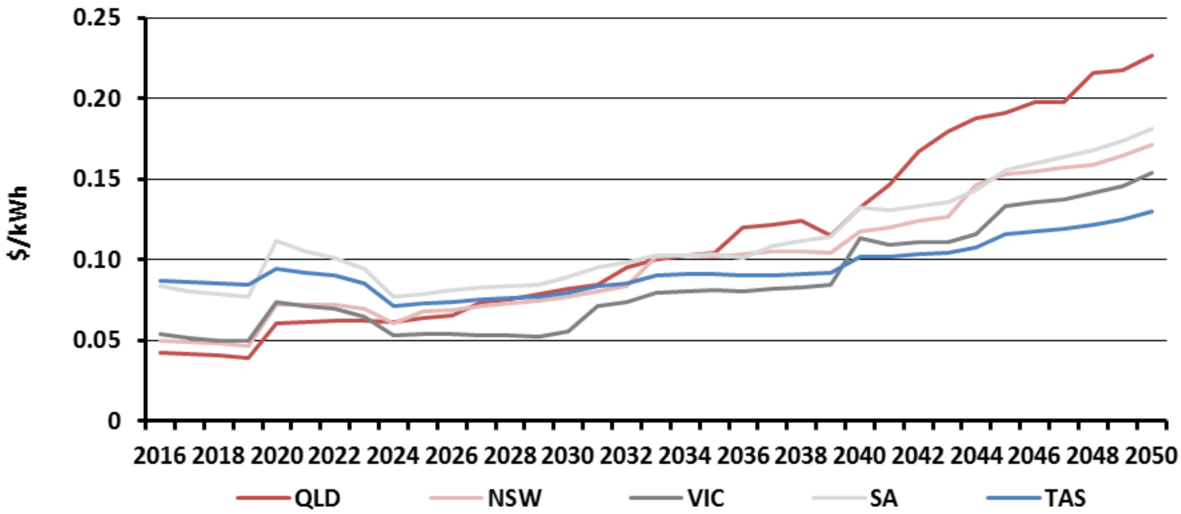


Figure 28 – Wholesale Market Volume Weighted Average Prices (Scenario 2)

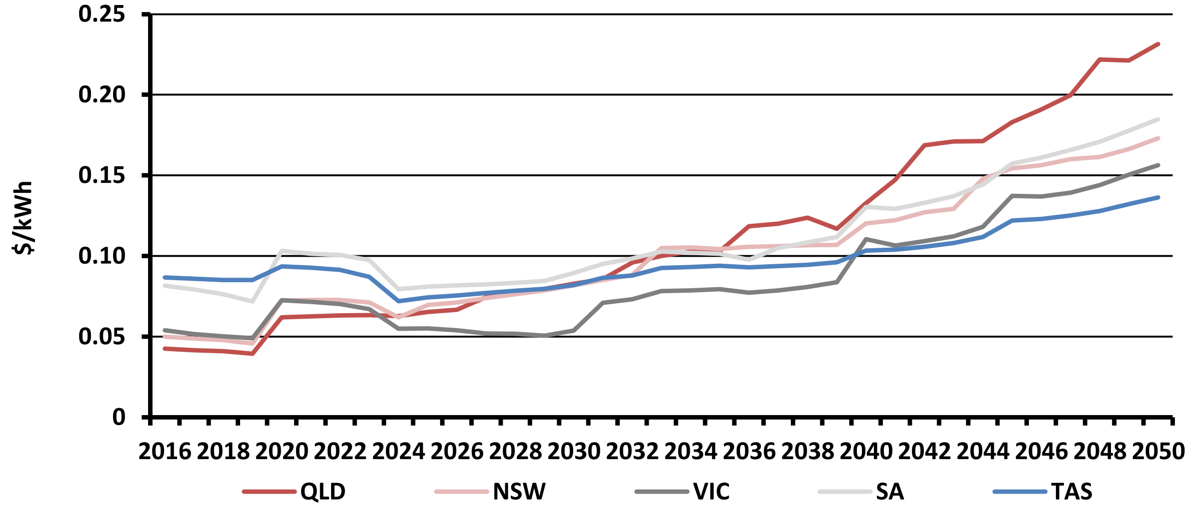


Figure 29 – Wholesale Market Volume Weighted Average Prices (Scenario 3)

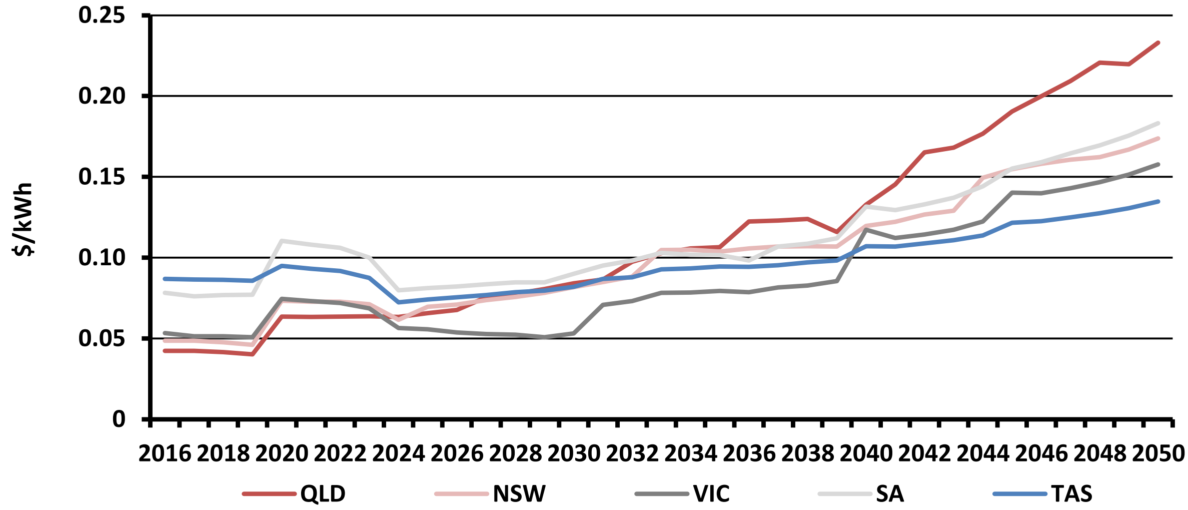


Figure 30 – Wholesale Market Volume Weighted Average Prices (Scenario 4)

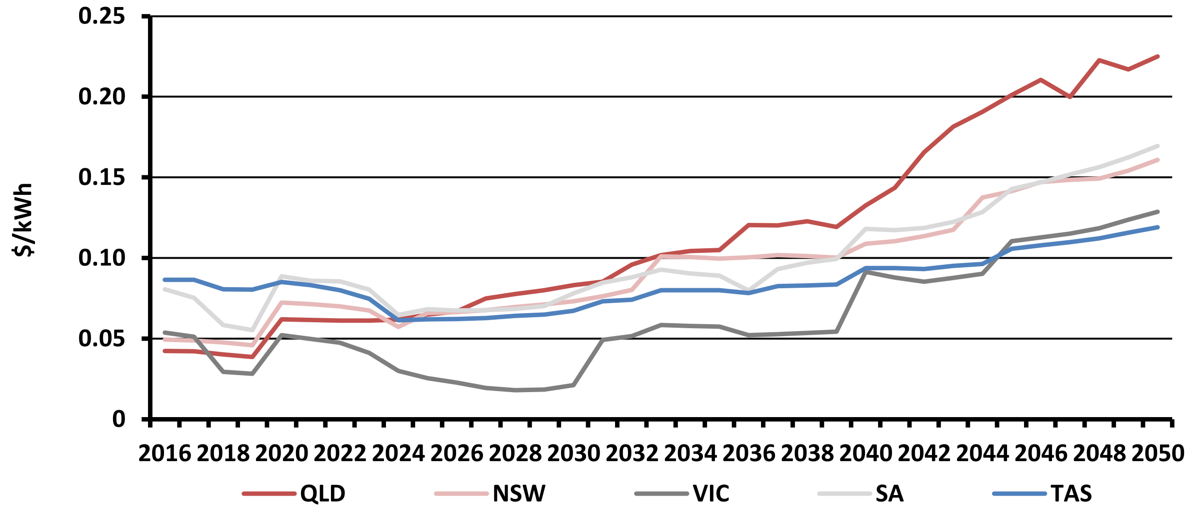


Figure 31 – Wholesale Market Volume Weighted Average Prices (Scenario 5)

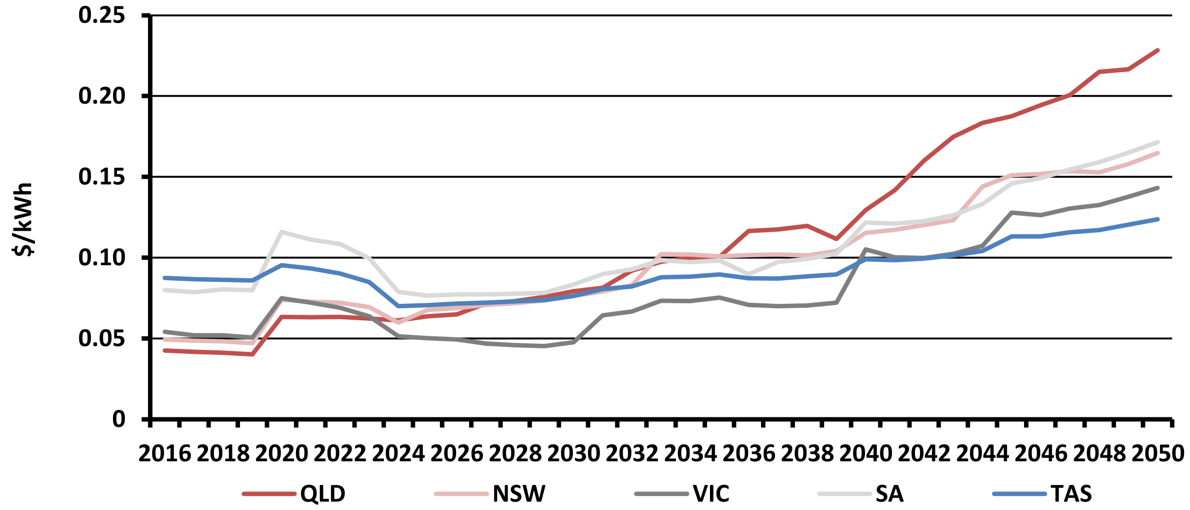
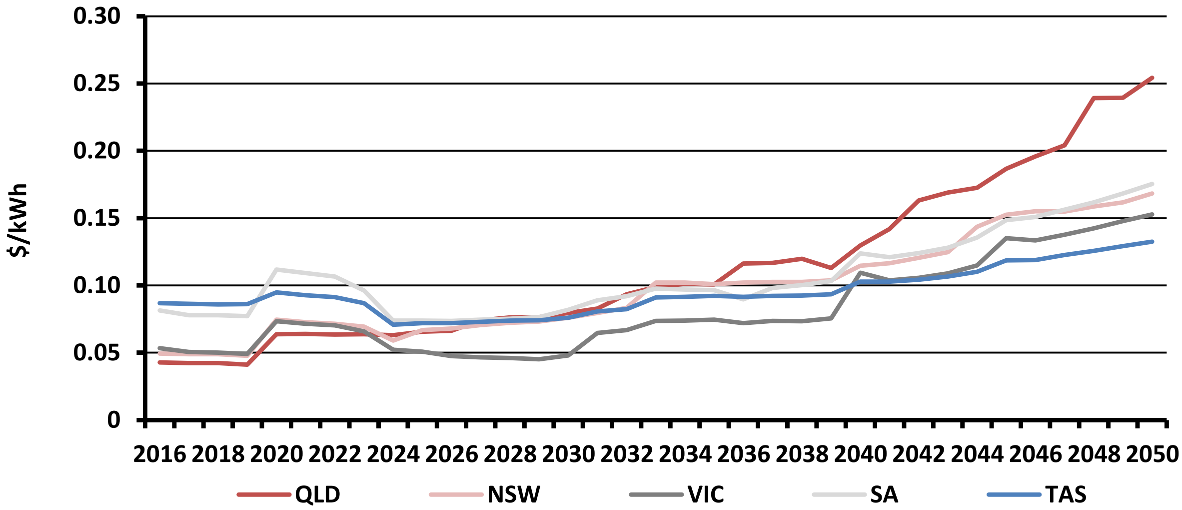


Figure 32 – Wholesale Market Volume Weighted Average Prices (Scenario 6)



Overall, there is very little difference between the scenarios. Across all scenarios, prices remain relatively stable between 5c/kWh and 10c/kWh depending on state, until around 2031 when prices begin to increase. The price increase is driven by the compounding effects of an increasing carbon price and large penetration of decentralised solar PV creating diurnal patterns in wholesale prices, increasing overnight prices and pushing prices negative during the day, especially in South Australia and Victoria.

Differentials between states grow over time due to increases in peak demand of around 40% without any assumed change in interconnector sizes. Queensland in particular has a highly constrained interconnector while Victoria struggles with too much coal that is forced to bid very negative values during solar hours. This pulls down Victorian prices. Victoria also sees prices reductions when SA is exporting renewable energy.

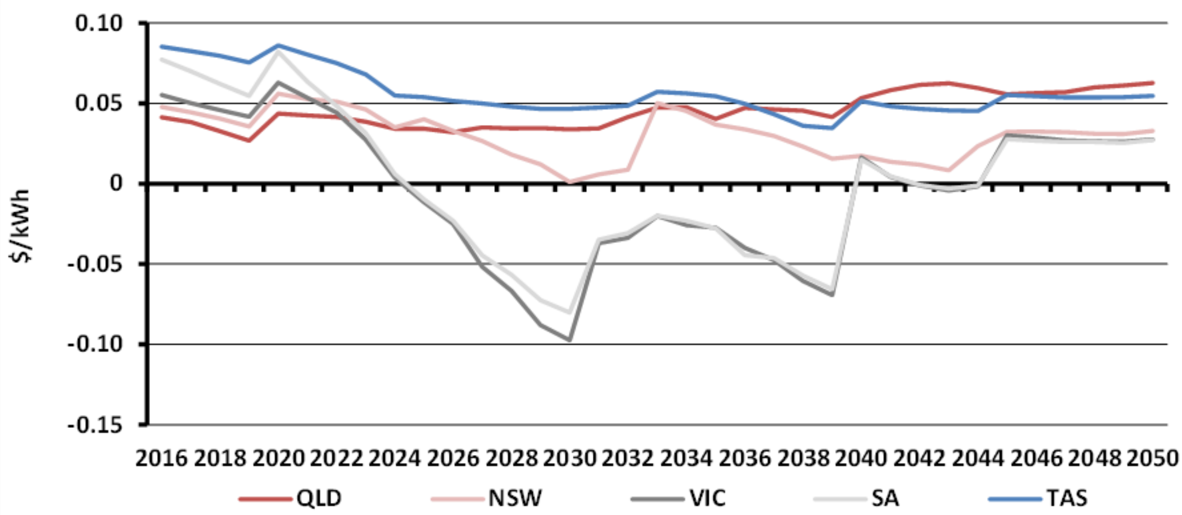
South Australia and NSW are very similar, both benefiting from interconnectors with Victoria and since interconnectors become constrained, they do not suffer from the extremely negative prices modelled for Victoria.

4.5.4 Feed in Tariff

Figure 33 shows the change in annual volume weighted average (VWA) price during solar export times for Scenario 1[38] which are then used to set the feed-in tariff offered to customers. The figure shows negative prices in some states in some years.

[38] Other scenarios are not shown here as only minor difference emerge but overall trends remain the same.

Figure 33 – Volume Weighted Average Solar Export Prices (Scenario 1)



The results show prices consistent with historical observations over the period to around 2024. After this time prices in Victoria, South Australia, and to a lesser extent NSW begin to decline to zero or negative

Zero and negative prices are driven by a combination of high renewables (both centralised and decentralised) penetration along with interconnector constraints which prevent export of excess generation into other states as well as the need for coal fired generators to bid negative. In Victoria, the low daytime prices are driven by negative bids by coal fired generators which in turn affect the South Australian market until such time as the interconnector becomes constrained.

The negative prices begin to recover from 2040 as coal fired generators are retired.

Notwithstanding the above, the modelling assumes that instead of passing through a zero or negative feed in tariff to the customer, the retailer will apply a minimum feed in tariff of 1c per kWh in order to retain and attract solar PV customers. The modelling further assumes that solar PV customers will continue to export during these times.

In practice, individual retailers would likely adopt their own feed-in tariff during this time depending on their business model. The robustness of the assumption should therefore be considered under the four potential retailer business models:

1. Gentailer – Operates significant centralised generation assets, but limited presence in decentralised market
2. Retailer Only – Has no generation assets
3. New Energy Services Business Only – Significant presence in decentralised market, selling exports into the wholesale market on behalf of the customer
4. Gentailer with New Energy Services Business – Significant presence in centralised and decentralised markets

Under any of these business models, there remains the incentive to apply a minimum feed in tariff during times of negative wholesale prices to retain and attract customers and so the assumption with respect to a minimum feed in tariff holds.

However, retailers with business models 1, 3 and 4 would be exposed to losses during these times. The gentailer (business model 1 and 4) is curtailing centralised generation or exporting its centralised generation assets at a loss during these times, while the new energy services business (business model 3 and 4) is required to pay the difference between the feed in tariff and negative price in the market for any export from its solar PV customers.

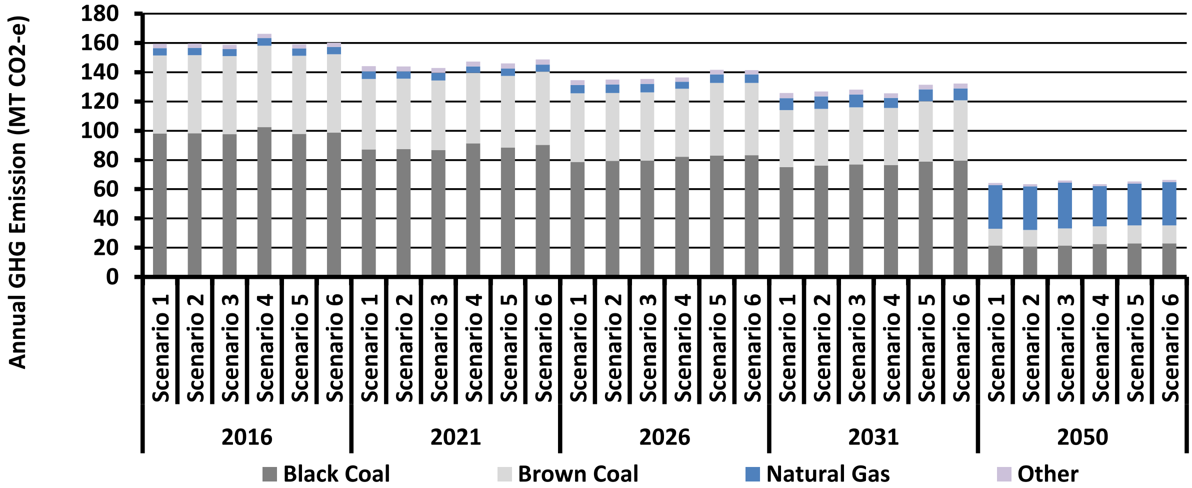
To counter these losses, the gentailer (business model 1 and 4 above) may seek to develop its own centralised storage assets to avoid export at negative prices. The New Energy Services Business (Business models 3 and 4) may seek to control or limit exports from decentralised generation via either storage technology or via orchestrating a cut off of solar PV exports during these times (in addition to the prospect that voltage issues at some locations may automatically trip off solar inverters regardless of the wishes of consumers or retailers). Each of these second order responses would involve costs which must be less than the potential losses modelled in order to proceed. For the sake of simplicity, the modelling did not attempt to address the likely prevalence of different retailer business models and the extent to which these approaches would be adopted by them. It is therefore assumed that the cost of these solutions would be exactly equal to the losses that are otherwise incurred.

4.6 Greenhouse Gas Emissions

4.6.1 Total Emissions

The total greenhouse gas emissions owing to the generator behaviour described above is shown in Figure 34 below.

Figure 34 – Annual GHG Emissions



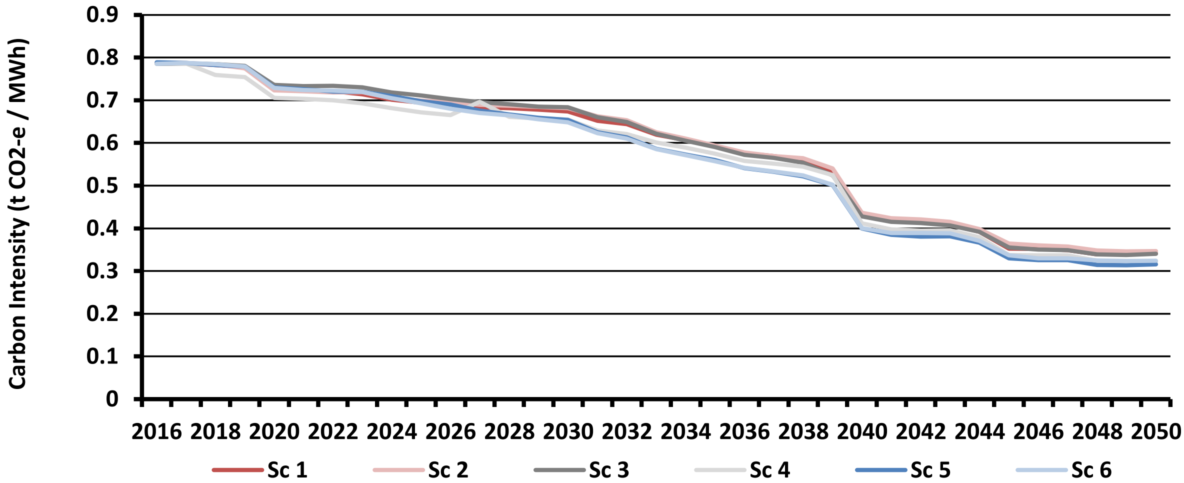
Greenhouse gas emissions from the centralised generation sector decline over time under all scenarios driven by reducing costs of renewable generation and an increasing carbon price. Black and brown coal continue to contribute the majority of emissions until around 2050, when natural gas becomes the dominant source[39].

Figure 35 shows the corresponding emission intensity of grid electricity.

[39] CSIRO's modelling initially projected lower emissions due to fewer planned hours of peaking gas operation in the period 2030-2050 in their plant build out model. Given the Energeia model found peaking plant hours of operation were higher, to achieve lower greenhouse gas emissions by 2050 whilst still meeting stability requirement, gas peaking plant capacity would need to be replaced with low emission alternatives such as gas or coal with carbon capture and storage, grid-scale batteries, new pumped hydro or switching to biogas fuel in peaking gas plant.

4.6.2 Emission Intensity

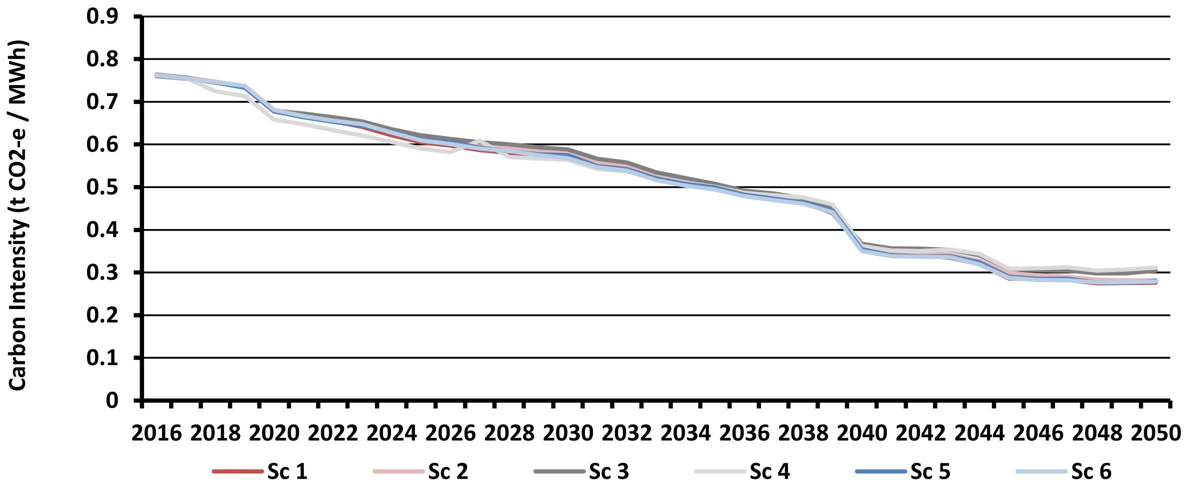
Figure 35 – Grid GHG Emission Intensity



Grid emission intensity declines over the period from around 0.76 tCO_2-e/MWh (Scope 2) in 2016 to between 0.65 tCO_2-e/MWh and 0.68 tCO_2-e/MWh in 2030 depending on scenario. By 2050, emissions further reduce to between 032 tCO_2-e/MWh to 0.35 tCO_2-e/MWh depending on scenario.

Emission intensity per unit of energy consumed (native demand) is shown in Figure 36 below.

Figure 36 – Total Consumption (Native Demand) GHG Emission Intensity



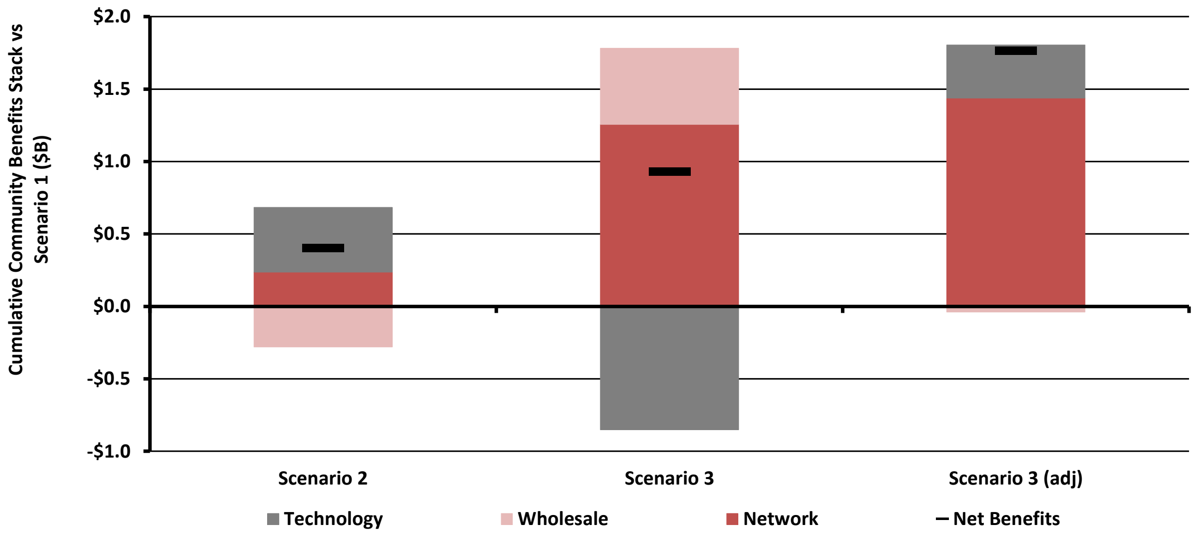
Emission intensity per unit of native demand declines at a faster rate than grid emission intensity, reflecting the large uptake of decentralised solar PV. In 2016, native demand emission intensity is around 3% lower than grid emission intensity. However, by 2030, the emission intensity of native demand is between 12% and 15% less than grid emission intensity and by 2050 is around 20% lower.

A large proportion of solar generation is “spilled” and so does not contribute to lowering of emission intensity. The modelling assumes that decentralised solar PV exported is able to be used by all other residential and business customers, but is unable to be exported to the large industrial centres (i.e. to the balancing load) and is effectively spilled. Where this constraint is overcome it could be expected that emission intensity of native demand would reduce.

4.7 Economic Benefits

Figure 37 below shows the additional economic benefits of each First Wave scenarios relative to the base case (Scenario 1) in 2026. The economic benefits include any change in network expenditure, any change in wholesale expenditure and change in expenditure in decentralised technology.

Figure 37 – Economic Benefits in 2026



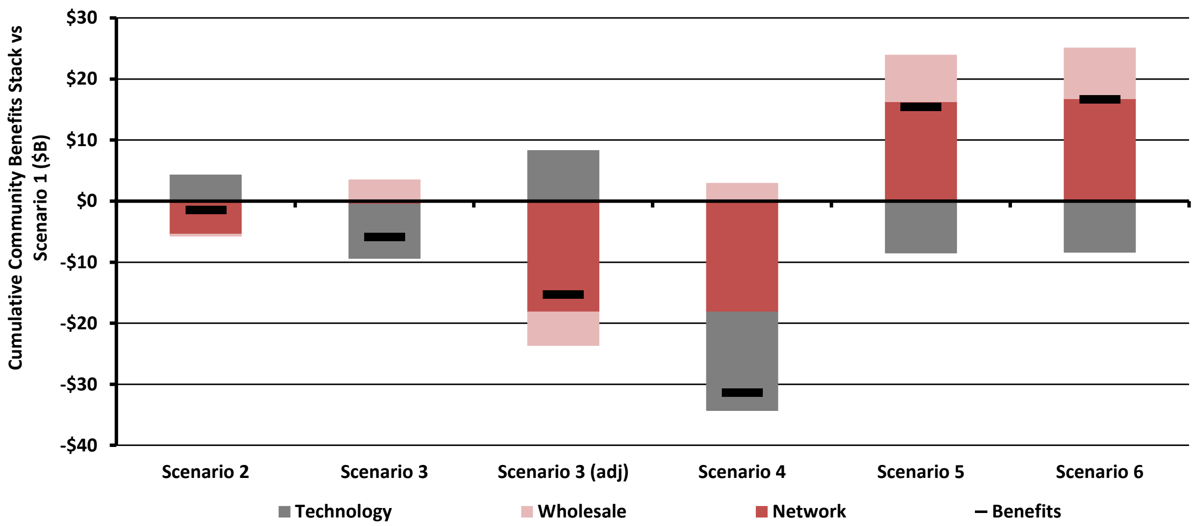
The results suggest that by 2026, Scenario 3 (Adjusted) whereby an opt-out tariff assignment mechanism is put in place by 2021 delivers the greatest overall net benefit of $1.8B. This scenario encourages less investment in DER compared to the base case, but is still able to deliver network and wholesale sector savings due to the more efficient use of the DER.

Scenario 2, requiring new DER customers to transition to First Wave tariffs, also performs well, delivering $0.4B in economic benefits over the period to 2025, via reduced network and DER expenditure.

Scenario 3 performs well as delivering $0.9B in benefits. While there is additional expenditure in technology compared to the base case under this scenario driven by a combination of the maximum demand peak signal and volume based component of the residual charge, this is offset by savings in network and wholesale costs.

Figure 38 shows the cumulative economic benefits of each scenario to 2050.

Figure 38 – Economic Benefits in 2050



By 2050, all First Wave tariff scenarios are no longer delivering a benefit as a result of increased investment in the network in particular, driven by the new zone substation level peaks from off peak battery charging. The benefits delivered in 2026 have been offset by 2050.

Scenario 4 has performed particularly poorly by 2050 due to the large incentives to reduce peak demand. As battery storage penetration increases under this scenario, it creates new peaks as a result of off peak charging further increasing the peak signal as this tariff continues to chase its own tail. This tariff would likely be withdrawn long before these impacts were realised.

The Second Wave incentives in Scenario 5 and 6 show strong performance, delivering $15.6B and $16.7B in economic benefits to 2050 respectively. Under Scenarios 5 and 6, the initial benefits of the opt-out tariff assignment mechanisms in Scenario 3 are retained as customers migrate to third party periodic use of battery storage from 2021, effectively mitigating any new peaks created by charging of batteries and optimising discharge of storage to defer augmentation or replace with zone substations with smaller capacity at the end of their lifespan.

Scenario 6 shows little incremental benefit compared to Scenario 5. Scenario 6 seeks to identify locations where new battery capacity should be installed in order to provide network benefits. However, the majority of network savings opportunities arise late in the period and by this time, for the most part, there is already significant battery capacity in place to deliver the saving. Thus, locating new battery capacity has relatively low value.

4.8 Bill Impacts

The following section describes the impacts of the results above on customer bills. The results are described in terms of average bills as well as the cross subsidies that arise which result in differences in bills between those customers who are able to adopt DER or actively switch tariffs where there is a bill saving and those that are not, due to a lack of education, knowledge, property ownership or physical space constraints.

4.8.1 Average Bill Impacts

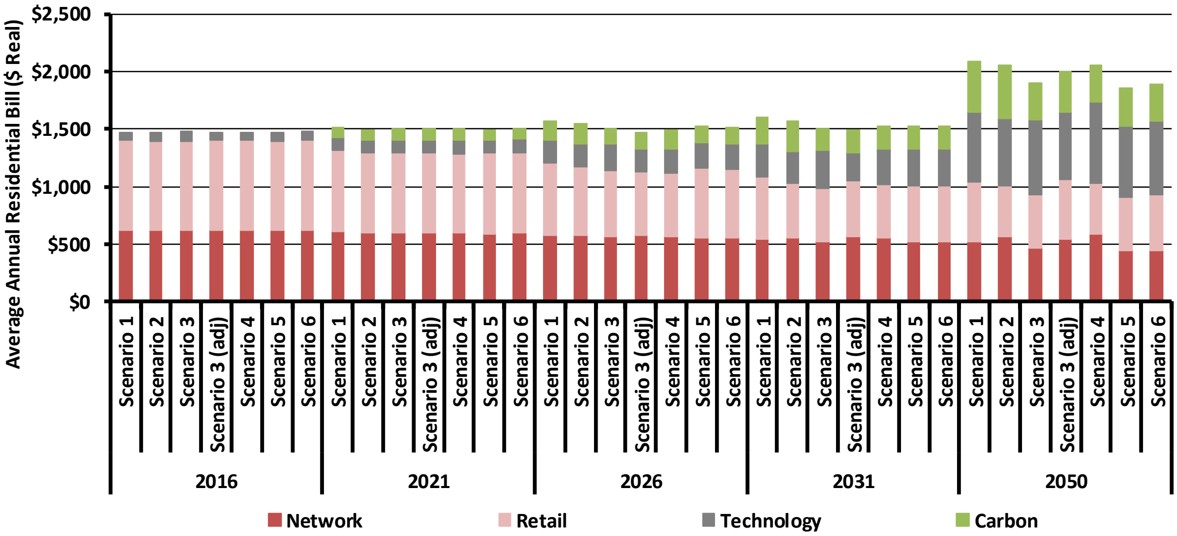
Average bill impacts are presented for residential and commercial customers for each component including:

- The average network tariff component
- The average retail tariff component (including wholesale generation and retail costs, but excluding the impact of the carbon price)
- The contribution of the carbon price to the average retail bill
- The average cost of DER technology

It should be noted that the average cost of DER technology does not appear on the consumer's bill (unless financed by the retailer) but is included for completeness, representing the total consumer expenditure on electricity supply.

Figure 39 shows the impacts of the tariff scenarios on average bills for residential customers.

Figure 39 – Average Residential Bills



Over the period to 2026, average residential bills remain relatively constant as the decline in the cost of DER is able to offset the increase in bills from the carbon price.

Overall, the opt-out mechanism under Scenario 3 delivers the greatest medium term benefits over the period to 2026 in terms of:

- A material reduction in the network component of the average ***residential*** bill of $60 or 9.6% by 2026 in Scenario 3 compared to 2016
- A modest reduction in total average ***residential*** bills of $8 per annum or 1% by 2026 in Scenario 3 (Adjusted) compared to 2016 levels (while all other scenarios show an increase)

From 2026, average residential bills begin to increase in real terms as the increase in carbon prices starts to outstrip declines in technology prices, which plateau around this time.

These factors continue to increase total bills to 2050, whereby larger investments in technology are required to offset the increasing component of the retail bill.

The modelling indicates that successful Second Wave tariff incentives (Scenarios 5 and 6), offering opt-in approaches from 2021 are able to:

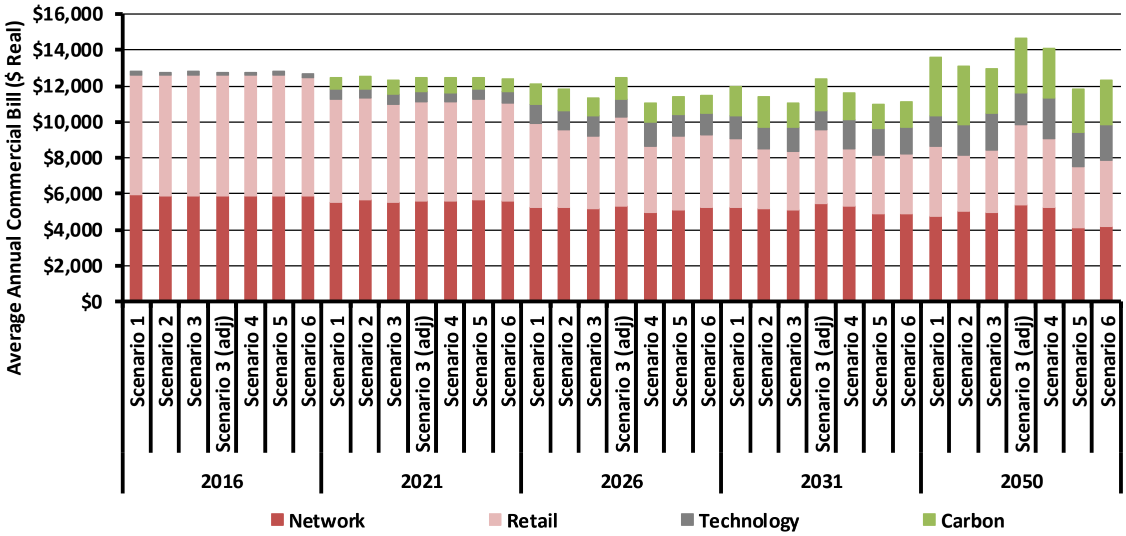
- Deliver overall ***residential*** bill savings of $256 or 12% compared to the base case
- Deliver a reduction in the *network* component of the average ***residential*** bill of $175 per annum or 28% by 2050 in Scenario 6 compared to 2016 levels

At first this may seem counterintuitive, due to the network price rises described in Section 5.4. However, by adopting technology (as well as underlying improvement in energy efficiency), customers on average are able to reduce their annual network bill. The network price rise is only felt by passive customers who cannot adopt technology, which is unable to be observed in terms of the average bill.

Overall, these results depict the challenges of undertaking network tariff reform in the context of Australia's carbon reduction commitments. As carbon prices rise, there are increasing incentives to uptake decentralised technology in order to avoid bill increases with customers willing to pay more for larger systems.

Figure 40 shows the average bill results for the commercial sector.

Figure 40 – Average Commercial Bills



In the commercial sector, overall average bills decline in real terms over the period to 2026 driven by two factors. Firstly, technology uptake is more effective at reducing bills compared to the residential sector due mostly to the alignment of solar generation with commercial consumption patterns. As a result, commercial customers, on average, spend a smaller proportion of their bill on technology than the residential sector. Secondly, underlying consumption reduces at a faster rate in the commercial sector than the residential due to energy efficiency as well as shift to less energy intensive industries.

Overall, the opt-out mechanism under Scenario 3 delivers the greatest medium term benefits for commercial customers over the period to 2026 in terms of:

- A reduction in average ***commercial*** bills of $1,512 per annum or 12% by 2026 in Scenario 3
- A reduction in the network component of the average ***commercial*** bill of $723 per annum or 12.2% by 2026 in Scenario 3 (Adjusted)

In 2031, the average commercial customer bill starts to increase in the scenarios with strong maximum demand, CPP and SAPS tariff uptake due to the impact of network price increases as a result of new peaks created by storage in these scenarios. Scenario 3 (Adjusted) and Scenario 4 have the greatest increase, reaching $12,361 and $11,621 respectively, making up any savings realised in early years.

By 2050, prices across all scenarios continue to rise such that they are well above 2016 levels with the exception of Scenario 5 and Scenario 6. The modelling therefore indicates that successful Second Wave tariff incentives (Scenarios 5 and 6), offering opt-in approaches from 2021, are able to:

- Deliver a reduction in average ***commercial*** bills of $972 per annum or 8% by 2050 in Scenario 5 compared to 2016 levels, offsetting the impact of the carbon price
- Deliver an even greater reduction in the *network* component of the average ***commercial*** bill of $1,766 per annum or 30% by 2050 compared to 2016 levels

Overall, the results in the commercial sector are more stark than the residential and highlight significant network bill savings available via a timely transition to Second Wave incentives.

4.8.2 Network Cross Subsidies

While average bill impacts is useful in terms of the overall effectiveness of the scenarios in driving consumer costs, the impact in terms of cross subsidies is of higher importance. Cross subsidies refer to the total amount spent by all consumers in order to make up the difference between:

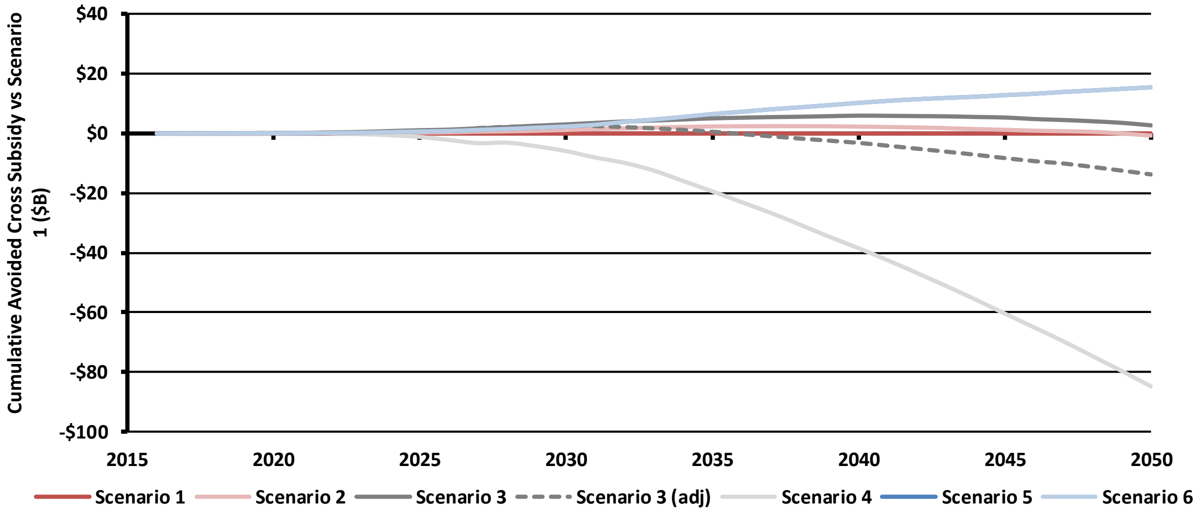
1. The amount of network revenue bypassed as a result of customer actions to adopt tariffs and DER technology and
2. The amount of network investment avoided by as a result of customer actions to adopt tariffs and DER technology.

This difference drives the network price rises described in Section 5.4.

However, the increase in network prices is not distributed evenly across all consumers and is concentrated in those customers who cannot adopt technology. Total cross subsidies is therefore used as the metric to identify inequity in tariff reform pathways.

Figure 41 below shows the total avoided cross subsidy compared to base case over time to 2050. A positive avoided cross subsidy indicates that the scenario performs better than the base case.

Figure 41 – Cumulative Avoided Cross Subsidies (Compared to Scenario 1)



Over the period to 2026, all First Wave and Second Wave scenarios perform better than the base case, delivering reduced cross subsidies. Scenario 3 performs the best of all scenarios delivering $1.4B in avoided cross subsidies. However, under Scenario 4, cross subsidies *increase* compared to the base case due to the additional network investment required to cater for new peaks driven by battery storage charging.

The benefits of First Wave reform however begin to deteriorate from 2026. Under Scenario 3 (Adjusted) the deterioration happens so quickly such that all benefits of Scenario 3 (Adjusted) are eroded by 2035. This is driven by a push of customers towards the SAPS tariff due to an increased fixed charge. The SAPS tariff then reaches a critical mass such that new peaks are created by SAPS customers from battery storage in preparation for a peak event.

Second Wave reform is able to address the issues in the First Wave tariffs as modelled by ensuring that battery storage is discharged in a way that increases utilisation to either avoid early augmentation or encourage replacement of zone substations with smaller capacities as well as to manage charging so as not to create new peaks. In this way, Second Wave incentives are able to both reduce the potential for battery storage to exploit any weaknesses in the tariff and to avoid unintended consequences of off peak charging. Overall, Scenario 5 and Scenario 6 both deliver around $18.6B in avoided cross subsidies over the period to 2050.

4.8.3 Customer Impact Case Studies

The analysis presented in the preceding sections describes the benefits of tariff reform at the average customer or total system level. However, as discussed in Section 2.1, customer usage is becoming increasingly heterogeneous so individual customer outcomes will differ, depending on the customer's own load profile and, in particular, the customer's ability to respond to network price signals and invest in DER technology.

Of particular importance is consideration of the cross subsidy, identified in Figure 41 and the way in which this is distributed between customer types. The extent of cross subsidy within a customer's bill depends not only upon the extent to which the customer is able to respond to price signals but also the extent to which a customer's load profile is vulnerable to paying high cross subsidies which differs by customer and tariff type. For example, a customer with high annual consumption but relatively low peak demand is more vulnerable to paying cross subsidies under a flat tariff than a passive customer with low consumption but high peak demand.

The amount of cross subsidy paid on an individual customer level is therefore highly specific to load profile characteristics. Due to the large degree of heterogeneity in customer load profiles, generalisations with respect to impact on certain customer types, even those with similar demographic characteristics, is challenging.

For the purposes of this study, the modelling included a set of 45 residential customer demand profiles per network which were identified by CSIRO as being representative from clustering analysis of a larger data set. CSIRO examined the available demographic data which included, for example, the number of occupants, number of children, age, as well as more technical details such as gas usage and type of air conditioner.

Based on this data, CSIRO selected four specific customers to represent the following households:

- Large family (six occupants, four children)
- Working couple (two occupants, no children)
- Medium family (four occupants, two children)
- Pensioner (single elderly occupant) households.

While no specific "vulnerable" customer type was identified, it is important to remember that any of these customers could be defined as 'vulnerable'. Vulnerability is related to many characteristics which might prevent an occupant from being able to access the available opportunities such as low disposable income, renting and low level of educational attainment. These characteristics could apply to any of the four selected customers.

The results below present the annual bills in 2026 and 2050 for each of the selected customers for each scenario comparing:

- The annual bill where the customer is **"active"** and makes a decision to adopt DER or change tariff in order to maximise financial return (sourced directly from the model)
- The annual bill where the same customer is **"passive"** and makes no decision (and is therefore assigned the default tariff with no DER calculated separately from the model)

Where a customer is better off remaining on the default tariff the passive outcome is identical to the active outcome.

The results presented are for Ausgrid customers. Ausgrid was selected due to having the largest number of customers and also due to the underlying load profile data having been originally sourced from the *Smart Grid, Smart City* trials based in Ausgrid's network. Customer impacts for other networks are provided in the Technical Modelling Report.

In summary, across all the customer case studies, the passive customers tend to suffer significant bill increases between 2016 and 2026 of up to 27% in real terms due to three main factors, increase in network prices, increases in retail prices including carbon costs and increase in underlying consumption for NSW residential customers. This impact is most pronounced for Scenario 1, while Scenario 3 tends to moderate the 2026 bill increases for passive customers (although not always) by reducing network cross subsidies and limiting growth in network prices.

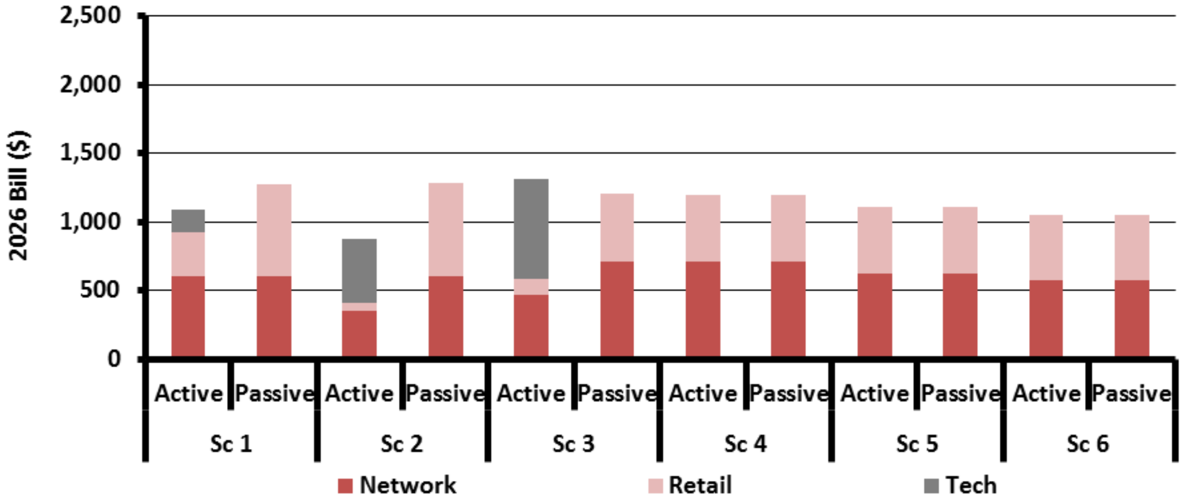
By 2050, all of the First Wave tariff scenarios tend to result in large bill increases for "passive" customers of up to 90% on 2016 prices. While these effects are greatly reduced under Scenario 5 and 6, it is clear that in all scenarios, the average bill benefits as discussed in Section 4.8.1 are not evenly distributed across customer types.

Detailed results for the individual customers are presented below.

Working Couple

Figure 42 below shows the annual bill for the working couple in 2026. The working couple nominated has an annual consumption of 5.5 MWh and a bill of $1,068 in 2016.

Figure 42 – Working Couple Bill in 2026 (Ausgrid)



Under Scenario 1, the “active” working couple has decided to adopt DER by 2026 and is able to reduce their bill by $178 or 14% compared to the “passive” working couple in 2026. The “passive” working couple’s bill has increased over the period between 2016 and 2026 by 19%, while the bill increase for the “active” working couple is limited to 2% over the same period.

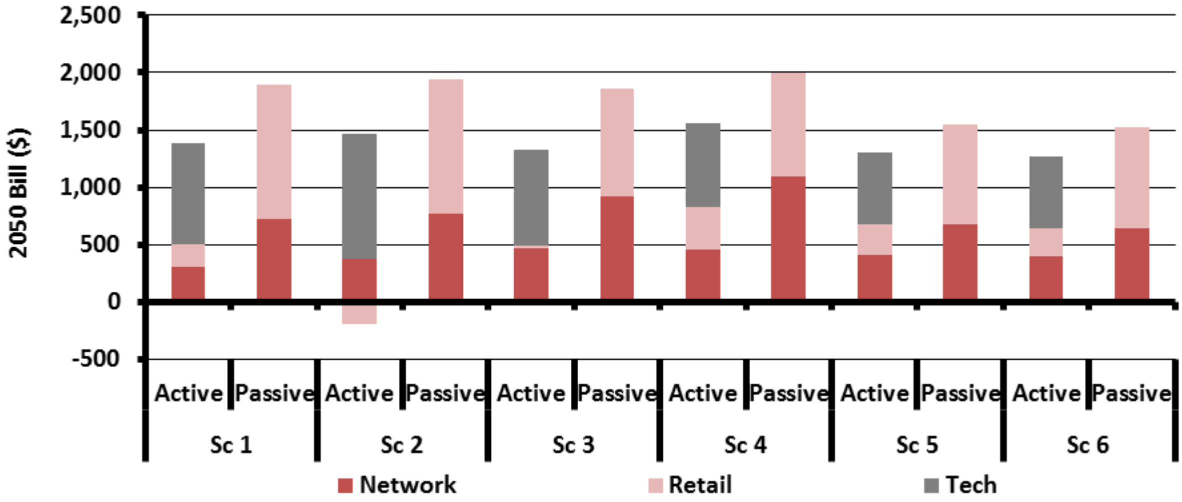
Under Scenario 2, the “active” working couple has decided to adopt slightly larger DER by 2026, resulting in an even greater bill saving of $402 or 31% compared to the “passive” working couple.

Under Scenario 3, the “active” working couple has also decided to adopt a large DER system prior to 2026. However, in 2026 their bill is 9% greater than the “passive” working couple. This effect can be observed in the model whereby the working couple has adopted DER prior to 2026 (and likely received savings in the first year after adoption) but then by 2026 network prices have decreased such that the technology is no longer delivering a saving.

Under the Second Wave scenarios, the active working couple has not adopted any DER or changed tariff by 2026, such that there is no difference between the “active” or ”passive” working couple.

By 2050, the differences between the “active” and “passive” working customer bills are more pronounced as shown in Figure 43.

Figure 43 – Working Couple Bill in 2050 (Ausgrid)



In Scenario 1 the "active" working couple has adopted more DER between 2026 and 2050 such that their bill is reduced by $513 compared to the "passive" working couple, but has still increased by 30% overall compared to 2016. Meanwhile the "passive" working couple's bill has increased by $832 or 78% over the same period.

In Scenario 2 and Scenario 3, the "active" working couple has adopted sufficient DER such that the retail component of their bill is practically zero (or net negative in the case of Scenario 2), due to income from the retail based feed-in tariff. As a result the "active" working couple has saved $675 on their 2050 bill under Scenario 2 and $533 under Scenario 3 compared to the "passive" working couple

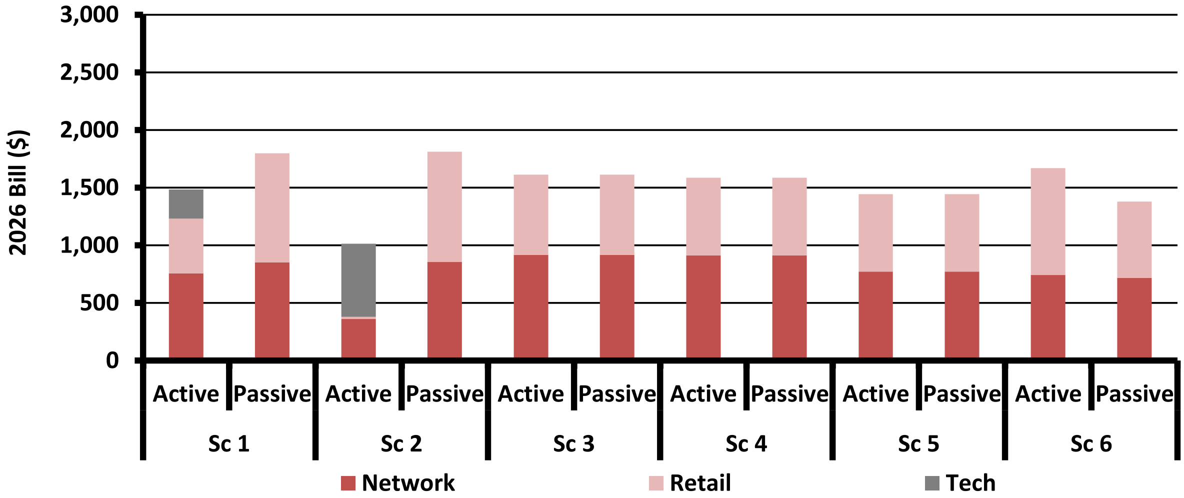
Under Scenario 4, the "active" couple has finally adopted DER by 2050 but is not able to offset their bill to the same extent as the first wave scenarios, due to the feedback loop on network prices in this scenario. This promotes higher investment in storage and less investment in solar, such that the retail component of the bill is not offset to the same extent as other scenarios. Under Scenario 4, the "passive" active couple has the highest bill of all scenarios due mostly to the network price rise observed. This customer is paying significant cross subsidies to counter the increased costs on the network created by "active" customers adopting storage.

Under Scenario 5 and 6, network price rises are contained such that investment in solar and storage is maintained at more efficient levels. The "passive" working couple under this Scenarios 5 and 6 has an overall bill increase of 40% and 45% respectively between the 2026 and 2050. However, the increase in the network component of the bill is more moderate at around 9% and 11% respectively over the same period, less than the increase in underlying consumption.

Medium Family

Figure 44 below shows the annual bill for the medium family Ausgrid customer in 2026. The medium family has an annual consumption of 5.8 MWh p.a. and a bill of $1,496 p.a. in 2016.

Figure 44 – Medium Family Bill in 2026 (Ausgrid)



Under Scenario 1, the “active” medium family has adopted DER prior to 2026 resulting in a bill saving of $315 or 17% compared to the “passive” customer. Meanwhile, the “passive” medium family’s bill has increased by 20% compared to 2016 levels, while the “active” medium family has saved 1%.

Scenario 2 presents even greater opportunities for the “active” medium family to save up to 44% on their 2026 bill compared to the “passive” customer. The improved DER opportunity in Scenario 2 compared to Scenario 1 is due to a combination of a higher feed in tariff and higher peak signal in 2026.

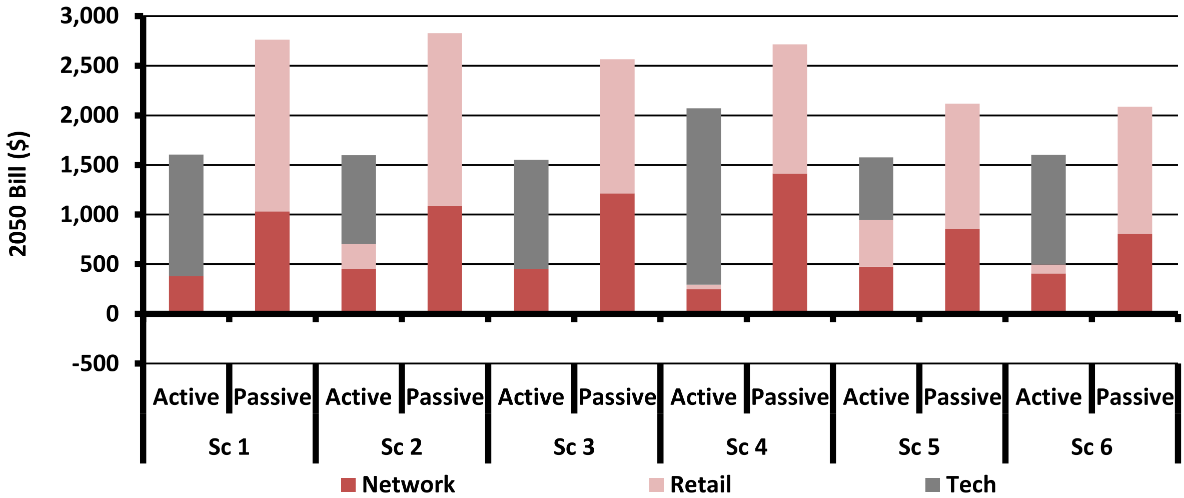
Under Scenario 3 to Scenario 6, the medium family is no better off adopting DER and so no adoption is observed. For these scenarios the medium family remains on the default tariff which by 2026 is the maximum demand tariff.

Under Scenario 6, the active customer has decided to switch tariffs prior to 2026 due to bill savings. However, the bill savings are not realised in the year 2026 and there is no opportunity to switch back to the legacy tariff due to it having being grandfathered.

Of the First Wave tariff Scenarios 1 to 3, the “passive” medium family customer is best off under the opt-out tariff assignment mechanism in Scenario 3. Further benefits to the passive medium family in 2026 are available under the Second Wave tariffs in Scenario 5 and 6.

By 2050, the differences between the “active” and “passive” working customer bills are again more pronounced as shown in Figure 45.

Figure 45 – Medium Family Bill in 2050 (Ausgrid)



Under Scenario 1, the “passive” medium family’s bill has increased to $2,761 by 2050, an overall increase of 85% on 2016 levels in real terms. The “active” medium family has a bill increase of only 6% over the same period, by reducing their bill by $1,584 or 43% compared to the “passive” medium family. Similar results are observed in Scenario 2 and to a lesser extent in Scenario 3 where the difference between the “passive” and “active” medium family’s bill is 40% by 2050.

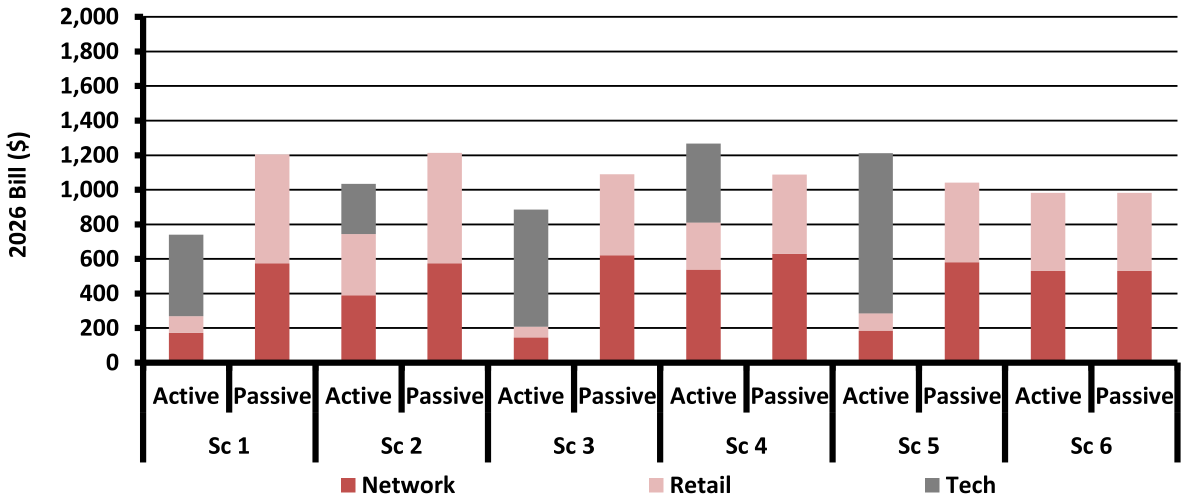
Under Scenario 4, the “active” medium family has adopted DER by 2050 but is not able to offset their bill to the same extent as the first wave scenarios, due to the feedback loop on network prices which was also observed for the working couple.

Under Scenario 5 and 6, network price rises are contained such that the network component of the “passive” medium family’s bill rises around 11% (less than underlying consumption growth limiting overall bill increases).

Retired

Figure 46 below shows the annual bill for a retired Ausgrid customer in 2026. The retired customer selected has an annual consumption of 3.5 MWh p.a. and a bill of $1,014 in 2016.

Figure 46 – Retired Customer Bill in 2026 (Ausgrid)



Under Scenario 1, the “active” retired customer has adopted DER prior to 2026, resulting in a bill saving of $464 or 39% compared to the “passive” retired customer. Over the period between 2016 and 2026, the “passive” retired customer’s bill has increased by 19%, while the “active” retiree has saved 27%.

Bill savings opportunities are also available, but to a lesser extent for the “active” retired customer under Scenario 2 and 3.

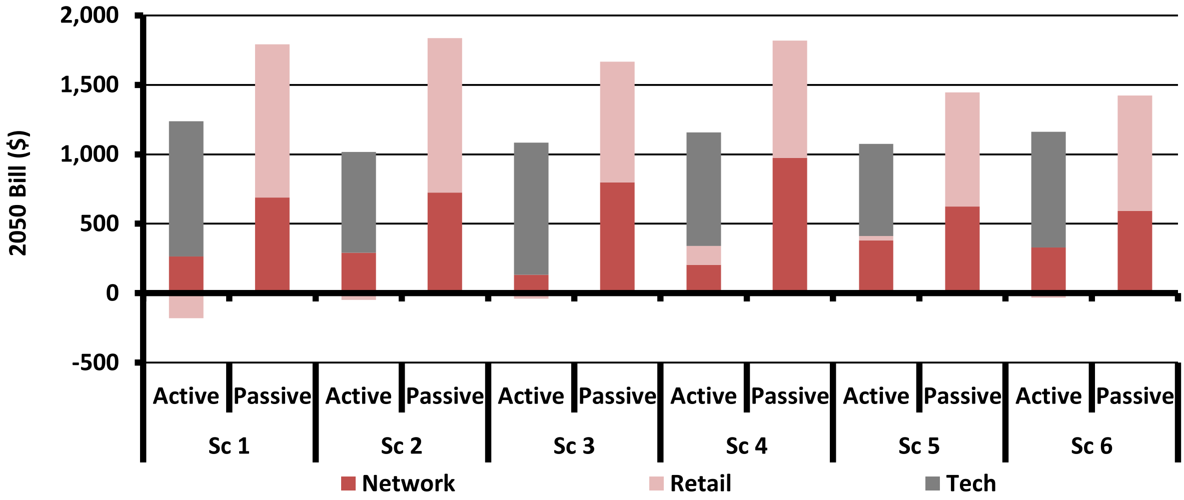
Under Scenario 4 and Scenario 5, the “active” retired customer appears worse off than the “passive” customer. Under these scenarios, the “active” retired customer had adopted DER early in the assessment period and received initial net bill savings, but then these are no longer available in 2026. The “active” retired customer is likely to be better off over the lifetime of the DER technology compared to the “passive” customer, however this is not reflected in the 2026 bill.

Under Scenario 6, the “active” retired customer is no better off adopting DER and so no adoption is observed. For these scenarios the retired customer remains on the default tariff which by 2026 is the maximum demand tariff.

Of the First Wave tariff scenarios 1 to 3, the “passive” retired customer is best off under the opt-out tariff assignment mechanism in Scenario 3. Further benefits to the passive medium family in 2026 are available under the second wave tariffs in Scenario 5 and 6.

The differences between the “active” and “passive” retired customer bills are further increased by 2050 as shown in Figure 47.

Figure 47 – Retired Customer Bill in 2050 (Ausgrid)



Under Scenario 1, by 2050, the "passive" retired customer's bill has increased to $1,792 by 2050, an increase of 77% compared to 2016. The "active" retiree is able to avoid the bulk of these bill increases, with bills increasing by only 4% over the same period. Similar results are observed in Scenario 2, Scenario 3 and Scenario 4 where the difference between the "active" retired customer's bill is able to limit bill increases or in the case of Scenario 2 generate a modest bill saving over the period to 2050.

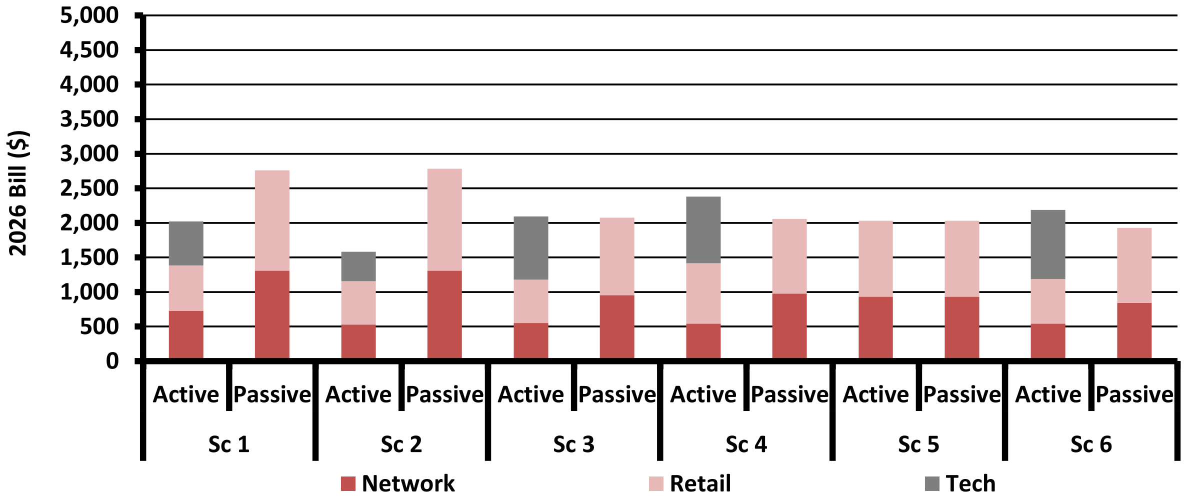
Under Scenario 3, the passive retired customer has a larger network bill than under Scenario 1 or 2, due to tariff assignment from the legacy declining block tariff to a maximum demand tariff but a reduced retail bill. The passive customer's network bill is the greatest under Scenario 4 due to the relatively poor performance of this scenario in driving up network prices by 2050.

Under Scenario 5 and 6, network price rises are contained such that the network component of the "passive" medium family under these scenarios rises by 8% and 12% respectively over the period between 2026 and 2050 (less than underlying consumption growth), while overall bills for the passive medium customer increase by around 39% and 45% respectively driven mostly by the carbon price impacts on the retail cost of electricity.

<u>*Large Family*</u>

Figure 48 below shows the annual bill for the large family customer in Ausgrid's network in 2026. The large family has an annual consumption of 11.1 MWh p.a. and a bill of $2,279 p.a. in 2016.

Figure 48 – Large Family Bill in 2026 (Ausgrid)



Under Scenario 1, the “active” large family has adopted DER prior to 2026 resulting in a bill saving of $738 or 27% compared to the “passive” large family customer. By adopting DER the large family has avoided any bill increase between 2016 and 2026, while the “passive” large family’s bill increase by 27% over the same period.

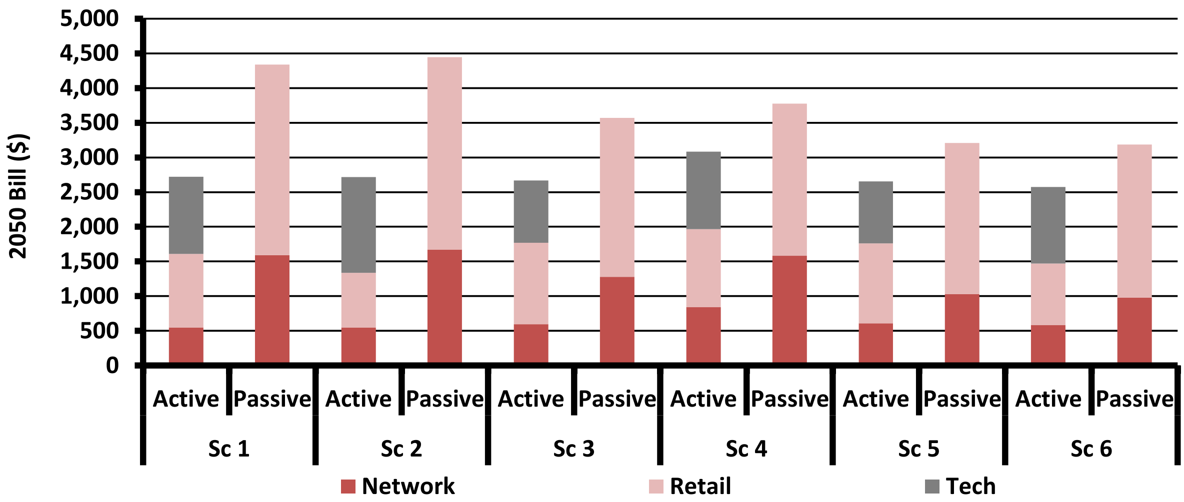
Under Scenario 2 the “active” large family can save up to 37% on their 2026 bill compared to the “passive” large family. The improved DER opportunity in Scenario 2 compared to Scenario 1 is due to a combination of a higher feed in tariff and higher peak signal in 2026 which provides higher returns to a customer on a maximum demand tariff. Under Scenario 2, the overall bill increase for the “passive” large family is 22% between 2016 and 2026, while the “active” large family saves 31%.

Under Scenario 3, Scenario 4 and Scenario 6, the “active” large family is slightly worse off than the “passive” large family in terms of their 2026 bill, having adopted DER prior to 2026 when bill savings were higher. Under these scenarios, the passive large family is able to reduce their bill over this time, indicating they are likely to be immediately better off under the maximum demand based tariff which is mandatory under these scenarios.

Of the First Wave tariff scenarios, the “passive” large family customer is best off under the opt-out tariff assignment mechanism in Scenario 3 which provides both an immediate bill benefit and limits network cross subsidies to 2026.

The differences between the “active” and “passive” large customer bills are again more pronounced in 2050 shown in Figure 49.

Figure 49 – Large Family Bill in 2050 (Ausgrid)



Under Scenario 1, the “passive” large family’s bill has increased by 90% over the period between 2016 and 2050 to $4,339. The “active” large family is able to limit their bill increase to 19% over the same period.

Similar results are observed in Scenario 2. The difference is somewhat contained in Scenario 3 and Scenario 4.

Both the network and overall bill outcomes are best for both the “passive” and “active” large family in Scenario 5 and 6. Under Scenario 5 and 6, network price rises are contained such that the network component of the “passive” large family under these scenarios rises by 11% and 16% respectively over the period between 2026 and 2050.

4.9 State Based Results

The following section presents the differences between different states in terms of total economic benefits and cross subsidies. The full set of state based results can be found in the Technical Modelling Report produced separately.

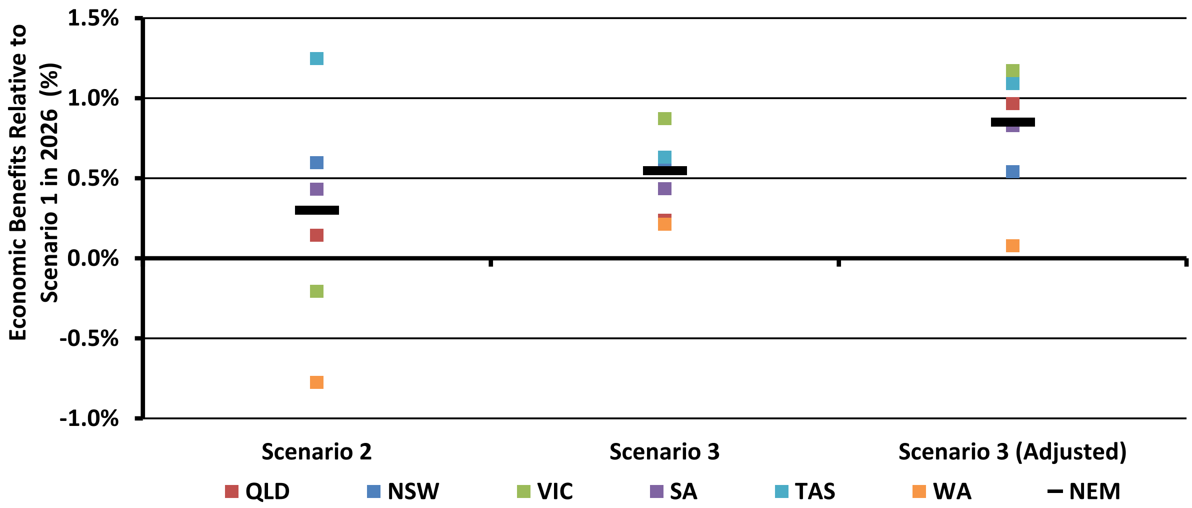
Each of the charts presented in this section display the NEM results as a solid black line with the respective state based results as different colour series, indicating which states are consistent with the NEM results and which are outliers.

Results between states differ for a number of reason. The key drivers of differences tend to be the starting values of energy prices (both network and retail), the level of demand, population growth forecast in each state over time and differences in tariff structure.

4.9.1 State Based Results – Economic Benefits

Figure 50 shows the relative economic benefits of First Wave reform in 2026 compared to the base case.

Figure 50 – State Based Economic Benefits of First Wave Reform (2026)

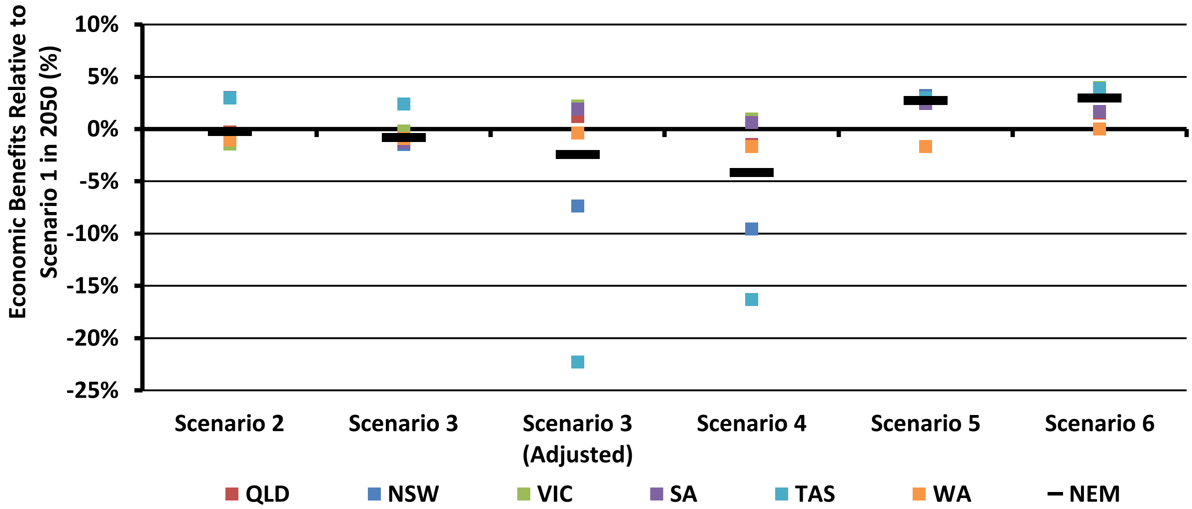


By 2026 all states show benefits compared to the base case from the switch to an opt-out tariff mechanism (Scenario 3 and /or Scenario 3 Adjusted) implemented in 2021. The benefits are greatest in Victoria and lowest in Western Australia.

The performance of Scenario 2 varies by state, with the mechanism to assign only certain customers (new and replacement and DER adopters) to alternative tariffs performing particularly well in NSW and Tasmania and poorly in WA and Victoria. In NSW, this result is driven by the form of the alternative tariff (declining block rather than maximum demand) which strongly discourages DER adoption for large usage customers and therefore inhibits large adoption of inefficient DER and improves economic benefits.

Figure 51 shows the relative economic benefits of First Wave and Second Wave reform in 2050 compared to the base case for both NEM and individual states.

Figure 51 – State Based Economic Benefits of First and Second Wave Reform (2050)



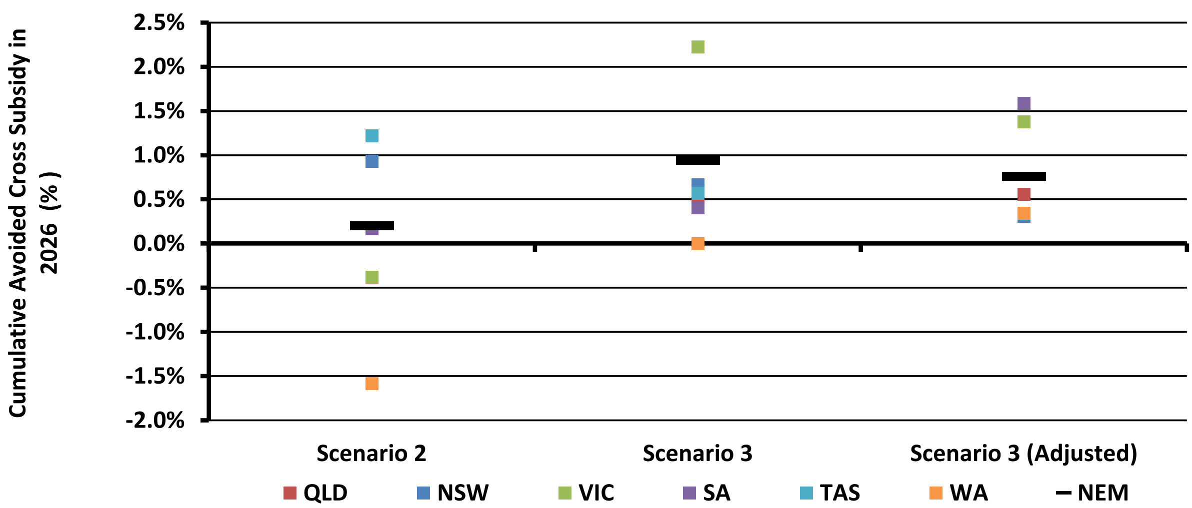
By 2050, the Second Wave reform scenarios outperform the base case in all scenarios (with the exception of Western Australia[40]) with the benefits relatively consistent between states.

While at the NEM level, First Wave tariff reform no longer outperforms the base case by 2050, this does not hold for certain states. In Tasmania, for example, Scenario 2 and Scenario 3 perform at least as well as the Second Wave reform scenarios. For Queensland, South Australia, and Victoria, Scenario 3 (Adjusted) continues to provide benefits compared to the base case to 2050.

4.9.2 State Based Results – Cross Subsidies

Figure 52 shows the relative avoided cross subsidies available from First Wave reform in 2026 compared to the base case.

Figure 52 – State Based Avoided Cross Subsidies of First Wave Reform (2026)



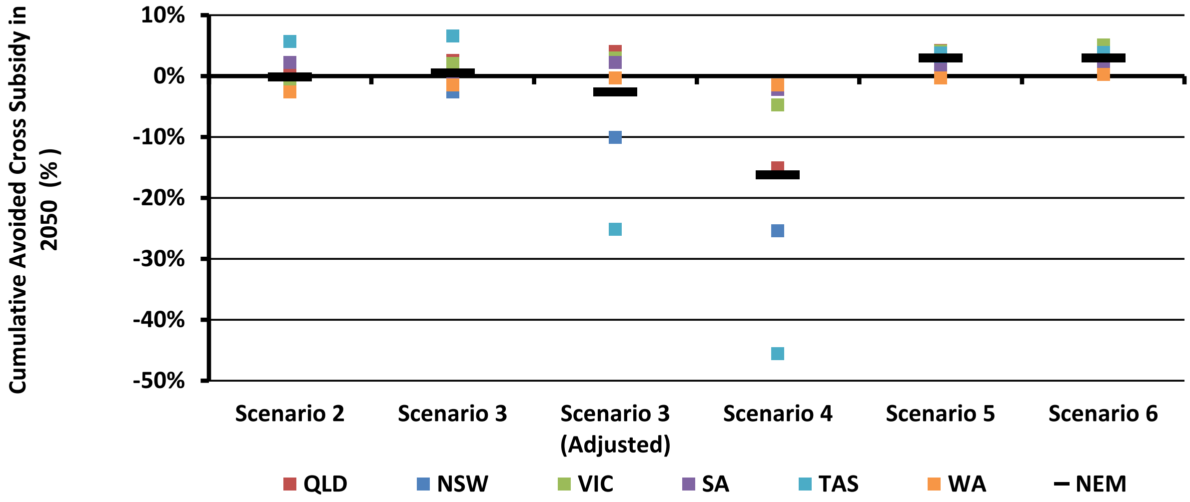
By 2026 all states show potential benefits in terms of avoided cross subsidies compared to the base case under First Wave reform. However, in Western Australia, Queensland and Victoria, the selective opt-out mechanism under Scenario 2 performs relatively poorly. The benefits of the opt-out mechanisms under Scenario 3 and Scenario 3 Adjusted are greatest in Victoria and lowest in Western Australia.

[40] Noting that the results for Western Australia are relatively insensitive to the scenario inputs due to declining demand

Differences are also observed between Scenario 3 and Scenario 3 (Adjusted) for some states. The higher fixed costs in Scenario 3 Adjusted performs particularly well in South Australia where DER adoption is otherwise at relatively high levels due to higher retail costs in this state.

Figure 53 shows the difference in cumulative avoided cross subsidies between scenarios compared to the base case by 2050.

Figure 53 – State Based Avoided Cross Subsidies of First and Second Wave Reform (2050)



Here it can be seen, that by 2050, the Second Wave reform scenarios are the only scenarios which demonstrate improved outcomes for all customers in all states. While First Wave reform continues to perform well in some states, it can be vulnerable to uptake of storage once storage achieves critical mass. For example, in can be seen that Scenario 3 Adjusted delivers large cross subsidies in NSW and Tasmania, due to storage in these states under this scenario reaching a critical mass and resulting in new peak charging events.

These results indicate that the required timing for transition to Second Wave reform may differ by states. In some states, certain "defensive" tariffs and low electricity prices relative to DER costs may prevent inefficient DER uptake over time. However, where technology prices decline faster than has been modelled, the timeframe for transition to Second Wave reform may need to be brought forward.

5 Conclusions and Recommendations

5.1 Conclusions

5.1.1 Significant Near Term Benefits from First Wave Tariff Reforms

The modelling shows that an opt-out approach to tariff reform in place by 2021 could deliver up to $1.3B in economic benefits and $1.4B in reduced cross subsidies across the NEM over the five-year period between 2021 to 2026.[41] Even greater benefits could be expected should the opt-out policy be implemented prior to 2021. However, this is considered unlikely given that no network Draft Tariff Structure Statement has proposed such an opt-out mechanism.

The improved performance of the opt-out tariff assignment is due to limiting the inefficient investment in solar PV which, under volume based tariffs, creates cross subsidies. In addition, the opt-out approach also ensures that both high cost to serve *and* low cost to serve customers are transitioned to the more cost reflective tariff and avoids the self-selection that otherwise occurs under opt-in approaches.

5.1.2 Vulnerability of Current First Wave Tariff Reform to Battery Storage

Despite the near term effectiveness of First Wave tariff reform, from 2026 the benefits of the maximum demand tariffs as modelled, start to erode. This is due primarily to the structure of maximum demand tariffs as currently proposed which are not well suited to a high penetration of distributed battery storage in particular.

Under the opt-out scenario, a critical mass of battery storage begins to expose limitations in current maximum demand tariffs due to widespread storage adoption and a number of issues emerge:

- The discharge of batteries during the peak period is only sufficient to influence the customer's own peak and so is limited in the extent to which it is able to provide locational network benefit[42]
- The charging of batteries in the off-peak period is uncontrolled and, under most of the proposed maximum demand tariffs, tends to commence as soon as the peak period is over, creating a new peak and effectively *increasing* network costs

These factors combined give rise to economic inefficiencies and as the creation of a battery *storage* cross subsidy issue, akin to the current solar cross subsidy issue whereby storage customers save on their network tariff without delivering network benefits, increasing costs for all consumers.

While the maximum demand tariffs as proposed do a good job in incentivising efficient investment in solar PV to 2026 compared to current volume based tariffs, they are less effective than the current volume based tariffs in incentivising efficient investment in battery storage. By 2030, the modelling shows that the benefits delivered by an opt-out policy become nullified.

5.1.3 Refining Current First Wave Tariffs

There are, however, many possible permutations to maximum demand based tariffs which can reduce vulnerability to exploitation by battery storage as well as unintended consequences. These include:

a. Reforming the peak charging mechanism so that it is more effective at reducing network peak demand. For example, applying the peak charge across a number of peaks (e.g. the average top four mechanism proposed by Ergon Energy) or adopting an average demand charge across the peak period.[43] Both approaches improve alignment between the peak charging mechanism and the actual network peak, and therefore customer and network benefits from investing in DER.

[41] In its modelling for ENA on the benefits of network tariff reform in 2014, Energeia assumed that opt-out was adopted from 2015, thereby delivering earlier benefits that are not captured here.

[42] This weakness has been previously highlighted by others (e.g Davies and Passey, See Section 2)

[43] Ref Mervyn's work?

b. Reducing the potential for network bypass by allocating a reduced proportion of the non-peak charge component away from volume based charges in order to reduce cross subsidies leading to over-investment and higher economic costs overall.

c. Incorporating mechanisms that increase diversity in battery storage charging outside of the peak period to avoid the creation of new network peaks.

There are also likely to be other mechanisms outside of tariffs which can be used to increase diversity in battery charging such as network controlled charging and or by mandating timer controlled charging through connection agreements. These mechanisms would reduce the potential for the creation of new peaks.

Scenario 3 (Adjusted) of the modelling attempted to identify the effectiveness of a restructuring according to option b) above, increasing the fixed component of the network tariff. This option reduced the residual anytime energy signal thereby reducing the inefficient signal for investment in solar PV and corresponding investment in battery storage.

Scenario 3 (Adjusted) showed that, if implemented early enough (in this case by 2021), there is the potential for increased fixed charges to reduce the incentive for solar/storage uptake thereby slowing penetration and buying more time to move to a Second Wave of reform. However, this was not the case for all networks. While this mechanism was effective in NSW, it proved to be ineffective in South Australia, where higher wholesale prices and existing levels of penetration meant that any restructure in 2021 was already too late to prevent a critical mass of storage uptake and exploitation of maximum demand tariffs.

Option a) and option c) above were not able to be modelled in the timeframe, but could provide more effective solutions.

5.1.4 The Need for a Second Wave of Reform

Whilst there are certainly mechanisms to improve the effectiveness of First Wave tariff reform, what is clear is that at some point, and likely well in advance of 2030, there is a need for more sophisticated cost reflective price signals which accurately signal both the locational and dynamic costs of supply. Such price signals ensure that the incentives provided to customers better match the costs and/or savings they impart on the energy system.

The modelling indicates that a move to Second Wave reform, offering opt-in approaches from 2021 is able to deliver $16.7B in economic benefits and reduce cross subsidies by $18.6B over the period between 2021 and 2050 compared to business as usual.

Furthermore, the Second Wave reform, delivers a range of opportunities for new service providers to participate in emerging energy markets. The modelling of Second Wave incentives (under Scenario 5 and 6) assumes that customers are provided an incentive in exchange for control of battery storage and potentially other home energy management systems. The modelling is agnostic as to what mechanism this is achieved by. Options may include via centralised network control, via a third party aggregator or virtual power plant.

Each of these options would allow for a “set and forget” customer environment, whereby the complexity of the real time and locational signals can be managed by the operator without the need to expose such price signals to the customer. The bill paid by the customer could in theory be relatively simple, such as a monthly fee, with the benefits of the tariff passed through at least in part, depending on the commercial or regulated business model of the operator.

5.1.5 Path Dependency of Second Wave Tariff Reform

The modelling included two key scenarios for Second Wave reform:

- Scenario 5, where control of existing battery storage was transferred to a centralised operator in exchange for a financial incentive
- Scenario 6, where both control of existing battery storage *and* investment in new battery storage according to locational constraints was managed by a central operator

The modelling revealed that Scenario 6 provided few additional benefits compared to Scenario 5. Under Scenario 6, virtually no additional storage needed to be deployed to manage locational constraints. This result suggests that the investments in behind-the-meter storage already made by consumers under sub-optimal First Wave tariffs was more than sufficient to address the limited number of future network constraints as they arrived.

This finding implies that the refinement of First Wave tariffs is critical to realising the full benefits of Second Wave reform. That is, suboptimal First Wave tariffs, without further restructuring will lead to an overinvestment in DER and storage in particular, such that the Second Wave reform will only be effective in optimising the operation of existing DER rather than the optimisation of investment in new DER.

5.1.6 Driving Smart Meter Investment to Deliver First Wave and Second Wave Reform

The AEMC's 2015 Competition in Metering rule change will essentially enable a roll out of advanced metering overtime via new and replacement meters from 2017. This, coupled with the already in place Victorian AMI rollout means that an increasingly large number of customers can transition to cost reflective prices without having to change out their meter and potentially incur an additional charge.

However, there is to date no requirement for any customer with an advanced meter to be assigned to a cost reflective tariff, implying that a large proportion of the advanced meter's potential benefits, in delivering cost reflective pricing, may go unrealised.

The modelling demonstrated that under the base case, approximately 76% of smart meters customers will not have adopted any form of cost reflective tariffs by 2026, improving slightly to 60% of smart meters in 2050. This implies that the benefits approximately $1.5B of smart meter investment in 2026 and $2.7B of smart meter investment in 2050, will not have been realised.

Under Scenarios 3, 4, 5 and 6 which introduce First Wave tariff reform on an opt-out basis in 2021, the benefits of smart meter investment are able to be better utilised. Under these scenarios, approximately 94% of smart meters installed are also delivering cost reflective tariffs by 2026 and 98% by 2050.

Despite these benefits, there are policy and logistical challenges to their realisation. The modelling assumes that smart meter deployment of around 4.3 million meters, at an approximate cost of $1.1B, can occur in conjunction with the mass tariff assignment in 2021.

The need for such a rapid deployment would be avoided if market led metering deployments are successful in achieving significant meter deployment before 2021. However, should it fail to eventuate by 2021, the modelling suggests further meter deployment would be rapidly required at scale to secure the potential benefits available to customers.

5.1.7 Network Reform in the Context of Australia's Carbon Reduction Commitments

The modelling of all scenarios assumes the same carbon price, set to reach around $60 per tonne in 2030 in order for Australia to meet its 2030 carbon reduction commitments to the Paris Climate Change Conference, and $180 per tonne by 2050. When the carbon price is applied to the scenarios here, it results in emission reduction of 30% to 33% below 2005 levels by 2030 and a 66% to 68% reduction by 2050. As such the abatement slightly exceeds the electricity sector's proportional share of the national target of 26% to 28% below 2005 levels by 2030. Whilst there is no national 2050 target at present it is likely that deep emission cuts will be required by this time and we discuss options for an alternative generation mix were greater abatement required.

The carbon price is adopted within the wholesale market modelling by incorporation into the short run marginal cost for fossil fuel generators representing a carbon price mechanism for the purposes of simplicity within this modelling. Other mechanisms and their impact on wholesale prices have been modelled separately by Jacobs as part of the Network Transformation Roadmap.

These carbon targets represent a deep-decarbonisation of the economy and will have material impacts on the wholesale cost of electricity regardless of the mechanism adopted. What is clear from the modelling, is that under such a carbon price, the wholesale cost of electricity, where passed through to consumers via a flat volume tariff (as assumed in the modelling), provides a strong incentive for uptake of solar PV.

The impact of this carbon price represents a challenge for network tariff reform. As networks seek to move away from volume based charges, the retail tariff components' volume based charges will likely increase to reflect the carbon price. While not modelled, there are actions retailers can take to improve the cost reflectivity of their own tariffs including time of use pricing and/or dynamic feed-in tariffs to manage the incentives that would otherwise encourage large exports of solar during the middle of the day.

5.2 Recommendations

Based on the results of the modelling, Energeia recommends that CSIRO/ENA consider the following recommendations as part of the ENTR Roadmap:

1. That opt out (rather than opt-in) tariff assignment frameworks be implemented as early as possible by regulators and network service providers as they deliver substantial economic benefit compared to status quo arrangements
2. That Australian Energy Market Commission, as part of its annual monitoring and reporting to COAG on technology trends and changes in market conditions, report on the pace of market led smart meter deployment to ensure that it is on track to deliver the required number of meter installations to transition to an opt-out tariff assignment framework from 2021.
3. That all DNSPs continue to refine cost reflective tariff mechanisms so as to limit cross subsidies and the creation of new peaks from battery storage. Robust structures should ideally be in place by 2021 and earlier where possible
4. That DNSPs consider more sophisticated tariff options in the medium term to deal with the likely penetration of new technologies. These include tariffs that allow for operational access to distributed energy resources on a dynamic basis in exchange for lower prices
5. That the AER consider the potential impact of emerging technology and in particular battery storage in approving DNSPs tariff structures as part of the Tariff Structure Statement (TSS) process and in doing so allow for the potential for refinement in tariff structures prior to the expiry of current TSS periods
6. That policy makers consider any regulation change necessary to allow tariffs to be refined more frequently than allowed for under the existing tariff structure statement cycle (which effectively locks in structures for five years) in the context of the current dynamic and changing environment
7. That the roadmap considers options towards the implementation of platforms to enable more granular pricing and incentive mechanisms. This should in the first instance enable network orchestration of discretionary loads and distributed generation on an opt-in basis to be in place from 2021 with the capability to integrate with more transactive mechanisms such as either real time incentives or location marginal pricing from 2026, should this be required
8. That DNSPs engage with retailers as soon as possible to identify integrated, cost reflective tariffs and incentive mechanisms that will better manage the identified issues along the path towards Australia’s climate commitments.