Roles and Incentives for Microgrids and Stand Alone Power Systems

Prepared by ENERGEIA for the Energy Networks Association

October 2016

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 distributed energy resources (DER) and active customers with heterogeneous attitudes towards technology.

While DER technology is expected to progressively lower the cost of delivering reliable, high quality and safe electricity over time, it is also potentially enabling customers to move completely off the grid, or to never connect in the first place. Where this is the most economic and equitable outcome, it is in everyone's best interests and should be encouraged. Alternatively, where this outcome is uneconomic and/or inequitable, network businesses should adopt price settings which discourage or, at the very least, avoid encouraging such outcomes.

Among the key challenges surrounding good policymaking, regulation and industry practice with respect to emerging microgrid technologies and business models is the lack of a framework for considering the range of potential options or an evidence base for estimating their respective costs and benefits. While some work on emerging microgrid issues has been undertaken by the ENA, it has been at a relatively high level to date.[1]

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.

This report is one of a series 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 NTR period to 2025.

Objective of this Report

The overall objective of this report is to assist ENA/CSIRO in identifying optimal roadmap measures related to integrated electricity pricing and incentives, network planning and asset management reforms aligned to the balanced score card adopted for the purposes of the NTR.

Specifically, this report seeks to set out, underpinned by quantitative analysis:

- The role of regulatory frameworks to 2025 in delivering timely and efficient microgrid enabled disconnection of individual customers and communities for the long-term benefit of all consumers;
- The role of alternative microgrid tariff products to 2025 in delivering timely and efficient grid disconnection for the long-term benefit of all consumers; and
- The quantifiable long-term risks to customers if fair and efficient frameworks and products are not established.

Approach

Energeia configured its simulation platform[2] to model the impact of various policy scenarios on the efficient uptake of microgrids, and the associated impact on customer bills and equity. This report considers the following types of microgrids:

- Existing, individual grid connected customers who adopt Stand Alone Power Systems (SAPS), which can operate in islanded mode or grid connected mode under a special SAPS tariff;
- New, individual customers who adopt a SAPS, which only operates in islanded mode, rather than connect to the grid; and
- Existing, grid connected communities, who adopt a microgrid solution as an alternative to grid connection and that operate in islanded (offgrid) mode only.

[1] Value of a Grid Connection to Distributed Generation Customers, Oakley Greenwood, October 2015.

[2] For detailed information about the simulation platform, please see the forthcoming report: *Network Transformation Roadmap: Work Package 5 – Energeia DER Simulation Platform Technical Report*, Energeia, 2016.

Six scenarios were developed to answer key modelling questions for the Network Tariff Reform study[3] as well as this Microgrid study. Thus, difference between some scenarios, while important to the Network Tariff Reform study are not material to this study. The key scenarios relevant to this report are summarised in Table 1 below.

Table 1 – Summary of Key Microgrid Scenario Settings

Scenario	Network Tariff Settings	SAPS tariff Availability	Fringe-of-grid Microgrid Settings
Scenario 1	Opt-In Maximum Demand from 2016 onwards	None	Traditional network delivery model
Scenario 3	Opt-In Maximum Demand from 2016 to 2021 Out-Out Maximum Demand from 2021 onwards	Opt-in from 2021	Traditional network delivery model
Scenario 3 (Adjusted)	Opt-In Maximum Demand from 2016 to 2021 Opt-Out Maximum Demand with reduced residual volume component from 2021 onwards	Opt-in from 2021	Traditional network delivery model
Scenario 5	Opt-In Maximum Demand from 2016 to 2021 Opt-Out Maximum Demand from 2021 onwards Opt-In incentive for centralised control of existing storage from 2021 onwards	Opt-in from 2021	Regulated microgrid

Source: Energeia

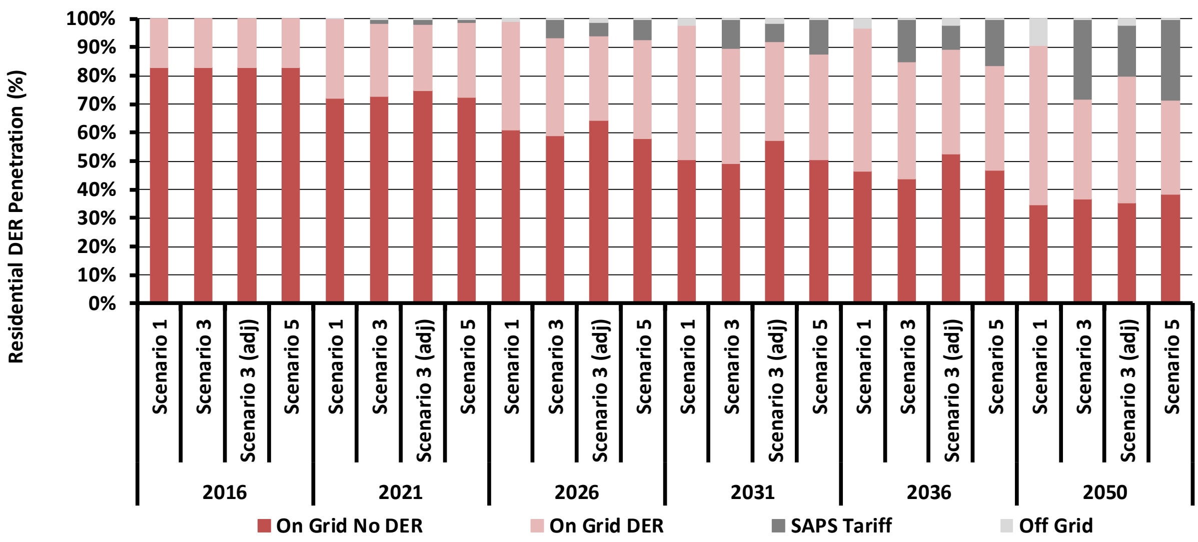
Key Findings

Although the modelling results are in terms of each scenario, most of the key findings have emerged from Energeia's meta-analysis of the results across scenarios.

<u>Customers Exiting the Grid[4]</u>

As shown in Figure 1 and Figure 2, SAPS uptake begins to rise significantly from 2026 under Scenario 1, with approximately 10% of customers leaving the grid by 2050. Scenarios 3-5, which feature a SAPS tariff, result in almost no off-grid SAPS over the period. Scenario 3 (Adjusted), which restructures tariffs in 2021 towards greater fixed charges, results in 1% of customers going off-grid by 2026.

Figure 1 – Cumulative Tariff Uptake (Residential)

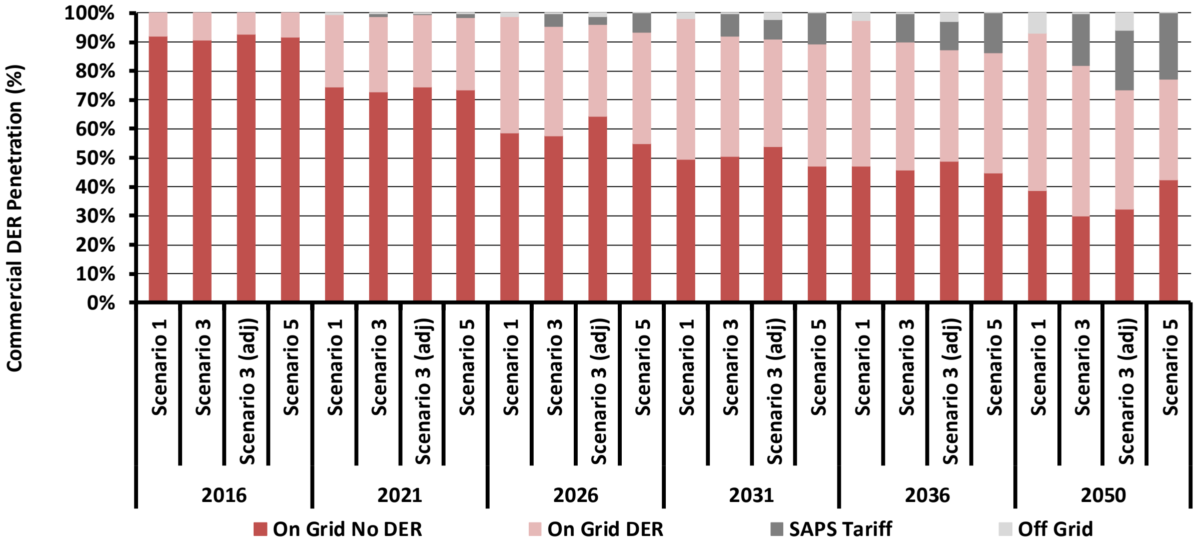


Source: Energeia

[3] Network Transformation Roadmap: Work Package 5 – Pricing and Behavioural Enablers Network Pricing and Incentives Reform, Energeia, August 2016

[4] A Stand Alone Power System is defined here as a microgrid type of that serves a single customer.

Figure 2 – Cumulative Tariff Uptake (Commercial)



Source: Energeia

Energeia's forecast of 10% of customers leaving the grid by 2050 under the baseline Scenario 1 is due to a combination of grid and diesel related factors. While solar and storage costs are expected to fall and grid costs are expected to rise over the period due to the impact of CO2 abatement costs, diesel prices are forecast to rise significantly more due to the combined effect of oil and carbon price increases.

Overall, the modelling showed customers are more likely to go off-grid in networks with relatively high average costs and with relatively high percentages of their residual costs being recovered through a daily fixed charge. The highest rates of SAPS adoption by 2050 were observed in South Australia, Queensland and Victoria.

The effect of customers going offgrid under current regulatory arrangements is an increase in residual costs needing to be recovered from customers remaining on the grid. Energeia estimates that grid-connected customers in Scenario 1 could expect to pay 4% more per year in present value terms due to the reallocation of residual costs that are no longer being recovered from customers who have gone off-grid.

Impact of a SAPS Tariff

In Scenarios 3-5, customers going off-grid were offered a 'SAPS tariff'[5] to encourage them to stay grid connected to be able to sell their excess PV, save money on their SAPS solution, and enjoy higher combined reliability. The modelling showed that such a tariff may be highly effective at keeping customers with a SAPS connected to the grid and mitigate the potential cost shifting seen in the Scenario 1 results.

Figure 1 and Figure 2 indicate that around 30% of customers adopted the discounted SAPS tariff under Scenarios 3 and 5, while customers instead choosing to go off-grid fell to almost zero. Scenario 3 (Adjusted) reduced residential SAPS tariff uptake to 20%, but increased off-grid SAPS to around 3%.

Overall, Energeia estimates that the introduction of a SAPS tariff would save all customers over $1.2 billion in present value terms over the period to 2050 by avoiding uneconomic investment in off-grid SAPS. This net benefit includes a modest discount[6] in the tariff's residual cost allocation, which is necessary to keep this new class of customers connected. Savings to connected customers is estimated at $1 billion per year by 2050.

In addition to avoiding higher bills due to cross-subsidies paid to customer going off-grid, the SAPS tariff also helps keep network and wholesale market costs in check by making SAPS available to networks for reducing

[5] The tariff operates like a critical peak tariff, but requires the premises to disconnect during critical peak periods.

[6] A 5% discount was applied to the residual costs in the modelling; alternative incentives could also be effective.

peak demand, and to retailers for reducing exposure to high wholesale prices. This benefit is incorporated into the overall Scenario 5 results, which reflect coordinated dispatch of DER.

Regulated Fringe-of-grid Community Microgrids

Energeia's modelling found that Australia's moderately sized communities (over 500 residents) at the fringe-of-grid, are generally unable to be cost effectively served by a microgrid by 2050 without specific local extenuating circumstances including significantly lower than average levels of reliability or significantly higher than average costs to serve. These will need to be determined on a case by case basis, rather than systematically.

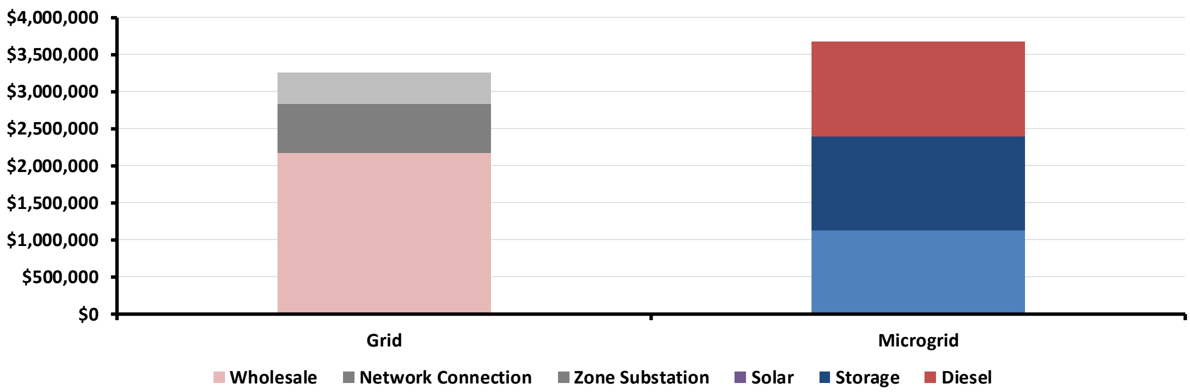
This result is due to a complex interplay of factors and assumptions in the Energeia modelling, including:

- rising diesel prices linked to oil and carbon price increases,
- the timing of grid infrastructure replacement, which is expected to mainly occur over the next twenty years, before microgrid technology is sufficiently low cost, or
- CO2 price driven increases in wholesale market cost are sufficiently high enough.

Diesel prices, including the impact of oil price and carbon prices needed to meet Australia's climate change commitments over time, increase to $580 per MWh by 2050, while grid prices in 2050 are around $165 per MWh. This leads to optimal microgrid solutions using less diesel generation over time, but it never becomes cost effective to run community microgrids without it.

Figure 3 shows the modelling results from the fringe-of-grid community in NSW in 2042 that came the closest in our modelling to becoming a cost effective microgrid. Sensitivity testing revealed that either a significantly higher cost of replacement or significantly lower level of reliability than the averages assumed in the modelling[7] would have made this community microgrid economic.

Figure 3 – Annual Costs of Rural NSW Community Microgrid vs. the Grid in 2042 (Case Study)



Source: Energeia, CSIRO, DNSPs, AEMO

While the above case study identifies how key drivers can make one of the most prospective examples cost effective by 2042, it is important to keep in mind that cost effectiveness depends on the costs of a microgrid and the timing of the network investment. For the modelling undertaken, key candidate fringe-of-grid communities tended to face a replacement driver prior to the microgrid becoming cost effective.

Unregulated Fringe-of-grid Community Microgrids

The modelling did not identify a single case of total customer bills in a fringe-of-grid community being less than the equivalent costs of a microgrid over the period to 2050 under any scenario. This reflects the current cross subsidies between customers on the fringe-of-grid, which are relatively high cost to serve, and customers in suburban and urban areas, which are relatively low cost to serve.

[7] Averages were used due to the lack of available asset specific data.

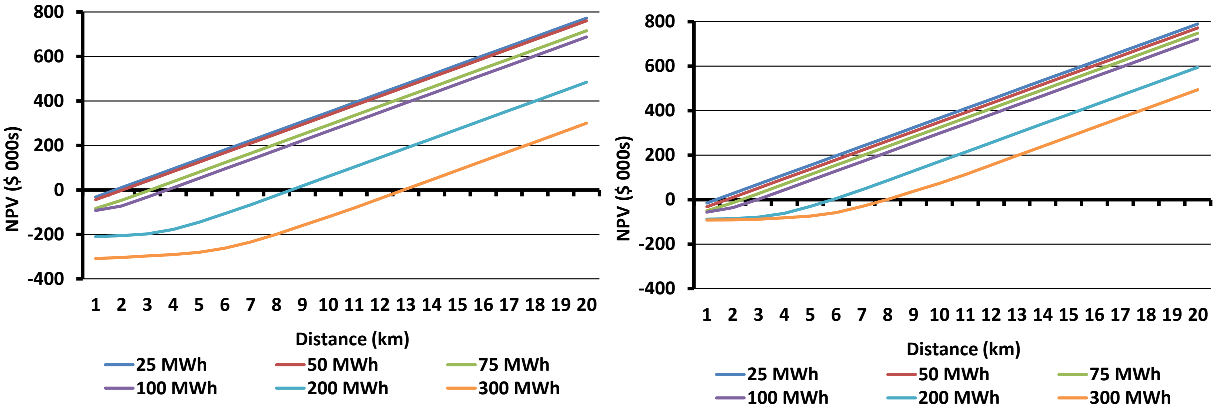
New Connection SAPS

Energeia's modelling of key new connection SAPS focused on rural agriculture sites such as crop farming, dairies, and cattle stations, and on mining or other large industrial loads.

The modelling found that even the smallest (100 MWh) new mines up to 500km away from the nearest line are likely to connect to the grid throughout the study period. The story for agricultural and other business customers was quite different, with the modelling showing the smallest (25 MWh) new farms sites being better off as a SAPS today, if they were more than 1 km from the existing grid. By 2020, small farms greater than 3km from the grid, and farms greater than 8km (irrespective of size) from the grid, are likely to be viable as a SAPS.

Figure 15 displays the net present value results for new farm SAPS ranging in size from small farms to large farms, depending on distance from the grid.

Figure 4 – Avg. NPVs of New Farm SAPS Connections by Distance in 2016 (Left) and 2020 (Right)



Source: CSIRO, DNSPs and Energeia

Decarbonisation Methods and Effects

Diesel generation remained part of an optimal microgrid solution to 2050, despite significant increases in diesel prices over the modelling period due to the assumed rise in oil and carbon prices. It is important to note that a different assumed carbon pricing approach, such as a rebate, could have a different impact on diesel prices for microgrids, and lead to more SAPS and community microgrids arising earlier than the above results.

Key Conclusions and Recommendations

Based on the key findings and conclusions presented above, Energeia makes the following recommendations to maximise community benefits from optimally integrating microgrid technology to 2050.

Network Tariff Reforms

Energeia recommends that electricity distributors 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. This is consistent with findings in our earlier report.

New SAPS Tariffs for Existing and New Connections

Energeia recommends that a trial of an integrated SAPS tariff is undertaken by networks which are most likely to benefit from SAPS tariff availability (i.e. South Australia, Queensland and Victoria). This will allow these networks and their stakeholders to gain sufficient experience with the tariff before it is available more broadly.

Fringe-of-grid Microgrid Solutions

Energeia recommends that electricity distributors work with regulators, policymakers, retailers and other industry stakeholders to remove the key technical, institutional regulatory and legal barriers from the efficient deployment of microgrids at the fringe-of-grid. Electricity distributors should also investigate the cost effectiveness of transitioning long-rural categorised SWER feeders to microgrid technology.

SAPS Enabling Services

Energeia recommends establishing appropriate technical and commercial arrangements to effectively support the SAP tariff. The SAPS tariff pilots recommended above would also help to establish the role of the distribution network and to identify its key technical integration requirements and potential solutions and their associated costs and benefits.

Policy and Regulatory Reforms

The influence of current diesel tax rebates and future carbon pricing on the cost effectiveness of microgrid solutions raises questions as to how these policy mechanisms will apply to rural and remote SAPS and microgrids. Energeia recommends clarification of Australia's carbon pricing scheme's operation with respect to fringe-of-grid SAPS and microgrids to give greater certainty to those considering these investments.

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1 Introduction

1.1 Background

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

- Update and build upon the CSIRO Future Grid Forum (FGF) work completed in 2013
- Identify the new services and technologies that future residential, commercial and industrial 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 engaged Energeia to undertake modelling to understand how tariff reform (including 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.

This report is one of a series 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 NTR period to 2025.

1.2 What is a Microgrid?

This report focusses on the roles and incentives for microgrids and Stand-Alone Power Systems (SAPS) whereby microgrids are defined as:

> *"A group of interconnected loads and distributed energy resources (DER) within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can be completely disconnected from the grid or may connect and disconnect from the grid dynamically to enable it to operate in both grid-connected or islanded mode"*[8]

For the purposes of this report, the term 'Stand Alone Power System' is used to describe a subset of microgrids supplying individual customers only. This report considers the following types of microgrids:

- **Existing Individual Customer Stand Alone Power Systems** – Individual existing grid connected customers who adopt SAPS which can operate in islanded mode or grid connected mode under a special SAPS tariff[9]
- **New Connection Stand Alone Power Systems** – New, individual customers who adopt a SAPS which only operates in islanded mode, rather than connect to the grid, due to the high upfront cost of grid connections requiring new lines. For the purposes of this report this is limited to the consideration of new farms and mines.
- **Fringe-of-grid Community Microgrids** – Existing grid connected communities who are high cost to serve from the centralised grid due to the length of lines that must be maintained and/or reliability issues, for whom a microgrid solution represents a lower cost (or more reliable) alternative to grid connection and operates in islanded mode only. Two subsets of fringe-of-grid microgrids are considered:

[8] Adapted from U.S. Department of Energy Microgrid Exchange Group

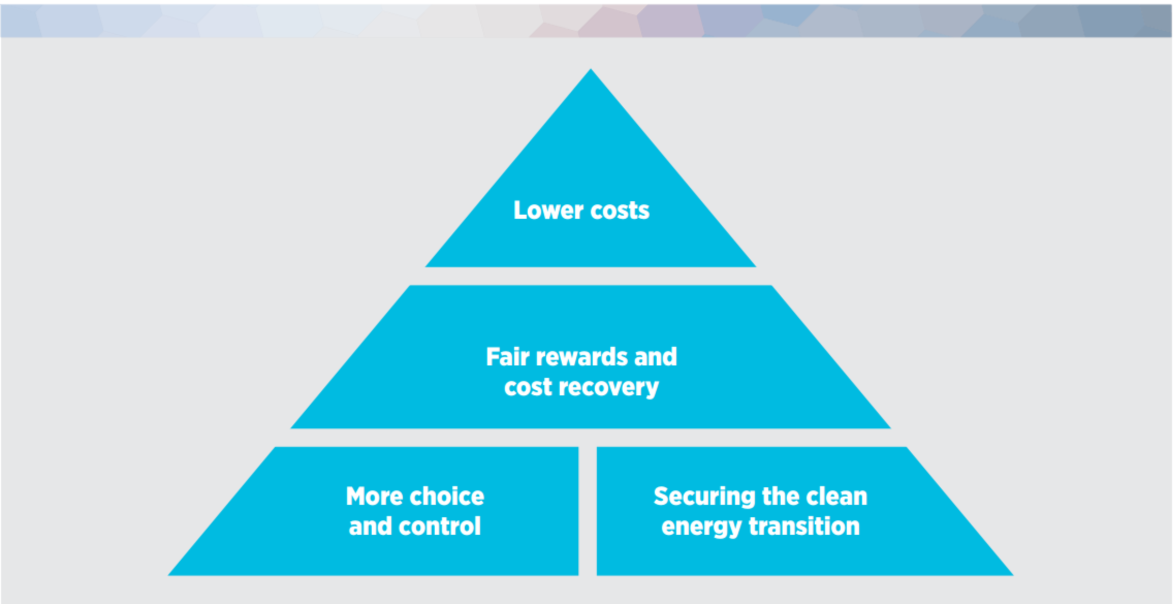
[9] This SAPS tariff acts as an alternative and potentially more attractive option for customers who may otherwise go off-grid. The SAPS tariff does not allow customers to consume any electricity during peak periods, in exchange for lower prices during off-peak times. Customers will only adopt the SAPS tariff where they are able to cost effectively install sufficient DER and/or sufficiently modify their behaviour to operate in islanded mode during peak times.

- **Unregulated Microgrids** – An islanded fringe-of-grid community operated by a third party under jurisdictional arrangements where there exists a commercial business case for the third party to provide such a service under prevailing tariffs.
- **Regulated Microgrids** – An islanded fringe-of-grid microgrid community operated either by a regulated entity or third party where the microgrid represents a lower cost solution from an economic perspective.

1.3 Purpose and Objectives

The overall objective of this report is to assist ENA/CSIRO to identify potential roadmap measures related to integrated electricity reforms which promote key principles of the CSIRO balanced scorecard (presented in Figure 5) adopted for the purposes of the ENTR.

Figure 5 – CSIRO Balanced Scorecard



Source: CSIRO

Specifically, this report, underpinned by quantitative analysis, seeks to set out:

- The role of regulatory frameworks to 2025 in delivering a timely, fair and efficient transition to microgrid technology for both individual customers and communities for the long-term benefit of all consumers
- The role of alternative microgrid tariff products to 2025 in delivering timely, fair and efficient transition to microgrid technology for individual customers for the long-term benefit of all consumers
- The quantifiable long-term risks to customers if such fair and efficient frameworks and products are not established.

This report, while acknowledging there is a role for retailers and generators in promoting efficient outcomes with respect to microgrids, is focussed on the role of network regulatory reform.

1.4 Report Structure

The report is structured as follows:

- **Section 1** – Provides the background and overall objectives of the report
- **Section 2** – Provides the relevant industry and regulatory context for the report
- **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.

1.5 Limitations

The results, conclusions and recommendations contained in this 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 this report. The material modelling limitations are documented below.

The modelling is driven by 4 key scenarios which by no means cover the full range of potential reform pathways. The study did not attempt to identify the optimal regulatory settings to deliver optimal outcomes, but rather sought to identify the relative performance of various plausible scenarios of future regulatory and tariff settings.

Most 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 NTR. 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.

The modelling was also dependent on publicly available inputs from DNSPs in the form of zone substation load profiles and is therefore subject to any errors in these inputs. Data analysis identified and excluded approximately 25% of network zone substations due to missing or obviously erroneous data. Large industrial customers were also excluded from the available dataset due to privacy issues.

Due to the above limitations, approximately 40% of NEM load was assigned to a balancing item and not subject to the effects of microgrid technology development over time.

Modelling of community scale microgrids was limited to avoidable augmentation and replacement capex and the reliability benefits based on AEMO derived customer value of reliable (VCR) metrics. It did not include specific reliability driven capex, due to a lack of data. Average Long-Run-Marginal-Costs (LRMCs) were used for network capex rather than location specific LRMCs, again due to the lack of more granular data.

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 annual forecasts of demand, 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 achieved in Australia or indeed, in any other country, to date.

2 Industry, Policy and Regulatory Context

This section covers the key policy and regulatory context affecting the efficient and timely uptake of microgrid technology, including drivers of and barriers to economic uptake, and the associated equity issues for customers remaining on the grid. How the study has attempted to inform the debate is highlighted in each case.

2.1 Microgrids in the Australian Electricity System

Microgrids are not uncommon within the existing Australian electricity system. A large number of sites, highly sensitive to reliability impacts (such as hospitals, data centres, airports and sites of importance to national security) have in place microgrid systems to allow for operation in islanded mode during grid interruptions. These types of microgrids tend to operate infrequently and tend to be supplied by diesel generation. Further, microgrids in remote communities, distant from the centralised grid, have long been a feature of Australia's electricity system, adopting diesel generation as a more economic alternative to the expansion of the existing grid.

This report is not concerned with existing remote area power systems which are never likely to be grid connected. Nor is it concerned with high reliability situations requiring islanded power supply for backup during the relatively infrequent times of interrupted grid supply. This study, and the NTR as a whole, is concerned with the efficient uptake of microgrid technology by new connections and existing customers *within* grid connected areas who are increasingly considering off-grid solutions as a more economic alternative to grid connection.

In recent times, the concept of a microgrid as an economic alternative to the grid for non-critical sites in existing grid connected areas is gaining increased attention, driven mostly by the decline in the costs of distributed solar PV, storage and load management technology.

It is the emerging opportunity to cost effectively disconnect from the grid, or to never connect to it in the first place, that has the potential to fundamentally change the way in which centralised grid infrastructure is managed, designed, priced and regulated

The cost of solar PV has decreased dramatically over the last 5-10 years, and this has had two major effects on the emergence of microgrids in Australia:

- Increasing consideration of diesel/solar hybrid solutions to reduce fuel expenditure; and
- Increased contribution of decentralised generation (solar PV) to Australia's electricity mix in grid connected areas.

In particular, the large uptake of solar PV in Australia, has delivered electricity bill savings to consumers (albeit assisted by generous federal and state based subsidies as well as favourable electricity tariff regimes), and opened up the possibility of reduced grid reliance or even complete grid independence for the Australian public.

However, solar PV technology in isolation is not sufficient to deliver a microgrid solution. Microgrid solutions require energy storage and/or diesel generation to provide energy demand during night times or on cloudy days when solar is not available. The emergence of a range of commercially available battery storage products in the last two to three years is rapidly reducing its cost, and driving an increasing number of individual consumers, businesses and communities to consider solar PV and battery based off-grid solutions, especially in urban areas where diesel generation is not likely to be appropriate due to local noise and air quality restrictions.

There is an additional type of microgrid associated with new large, mostly residential developments, which is not further considered in this report. This type of microgrid is expected to be driven for the foreseeable future by forces other than energy economics including environmental credentials, as well as a shift towards localised utilities (encompassing water and waste services supply) as an emerging business model for developers.

2.2 Barriers to Economic Uptake of Microgrids

Where economic, microgrids have the potential to result in a lower cost electricity supply system for the benefit of all consumers. That is, where individual consumers or communities have a high annualised cost to serve and exit the grid, the cost of supply for the remaining customers should, in theory, decrease.

It is therefore in the interests of policy makers and regulators to ensure that barriers to economic exiting are addressed. This study focusses on three key barriers to economic uptake of microgrids:

- Network tariff structure
- Jurisdictional tariff policies
- Regulatory settings for network deployed solutions.

These are discussed below.

2.2.1 Network Tariff Structure

The network tariff structure sends a price signal to the end consumer as to their network cost to serve. A tariff's structure refers to its particular combination of tariff charging components. Cost reflective tariffs include at least one peak component, which is set to recover the cost of a customer's use of the network during time of maximum or peak demand, and a residual cost component, which is set to recover the residual costs.

Where a network tariff is 100% cost reflective, an economically rational consumer will choose to leave the grid only where the decision benefits the entire network, because the consumer and network incentives are 100% aligned. In the absence of 100% cost reflective network tariffs, customers may see an incentive to leave the grid to avoid costs to themselves, without also lowering costs for everyone else. This represents a cross-subsidy paid to those leaving the grid, paid for by those remaining on the grid, and increasing their costs.

Current tariff structures are not 100% cost reflective and therefore have the potential to drive uneconomic uptake of microgrids for all three types of microgrids. For example, tariffs with a relatively high fixed charge can result in relatively high prices for small consumption customers, and make going offgrid attractive, even though these same customers may actually be relatively low cost to serve.

The key questions facing industry, consumers, policymakers and regulators alike is the impact of current and various proposed network pricing structures on the efficient uptake of SAPS and fringe-of-grid microgrids. The study therefore focuses on identifying the scope, level and timing of economic and uneconomic microgrid uptake across a range of feasible tariff structures, including a new SAPS tariff designed to mitigate uneconomic bypass.

2.2.2 Jurisdictional Tariff Policies

In addition to inefficiencies within network tariff structures themselves, many jurisdictions also have uniform tariff policies. Uniform tariff policies are set at the retail level to ensure that rural customers pay no more than urban customers, even though their cost to serve may be markedly higher. Any shortfall between the actual costs to the network service provider and the amount paid for by consumers as network charges is subsidised by other, typically lower cost to serve customers living in urban areas. Queensland, Western Australia and Northern Territory all have state government mandated uniform tariff policies in place, at least for small customers.

Other networks which cover diverse geographic areas and do not distinguish tariff classes by grid location, also effectively have uniform network tariffs in place. This includes SA Power Networks and TasNetworks.

Uniform tariff policies are often favoured by governments to ensure that customer access to energy as an essential service does not discriminate based on location. From another perspective, however, these uniform tariff arrangements can serve as a barrier to cost-effective microgrid deployment because they hide the true cost of supply in locations and prevent competition that might otherwise drive microgrid investment. While the impact of such policies on economic microgrid uptake has been acknowledged by some jurisdictions[10], there can be significant political implications of unwinding such policies through tariff reform.

Importantly, uniform tariffs themselves do not prevent the regulated network or retailer from using microgrid technology where more efficient, but there are other regulatory settings which prevent this.

[10] For example, the Queensland Productivity Commission acknowledges in its 2016 Draft Electricity Pricing Inquiry that "[the Uniform Tariff Policy] dampens price signals for customers about the actual costs of electricity usage, which can impact on efficient network investment—including discouraging non-network alternatives"

2.2.3 Regulatory Settings

In the near to medium term future, current cost trends suggest that microgrid solutions are likely to represent the lowest forward looking cost solution for supplying existing customers in some specific circumstances. This might occur, for example, just prior to replacement or augmentation of long radial lines in rural areas and/or in extremely remote areas where there are unusually high maintenance costs and reliability performance issues.

The current regulatory framework can serve as a barrier to efficient regulated and unregulated deployment of fringe-of-grid microgrids in these situations due to a host of unresolved regulatory issues associated with disconnecting customers from the grid under the National Electricity Rules, related to:

- Cost recovery of microgrid assets, including non-traditional network assets such as generation
- Customer protections, including service levels, price controls and access to full retail competition
- Third party access arrangements

Additionally, under current arrangements, regulated networks are unable to offer an unregulated affiliate or a third party the full network savings realised from cost effective deployment of a microgrid solution. Deferred or avoided investment could be passed on, but other avoided costs would accrue to all grid connected customers.

Finally, competitive microgrids can only proceed where the microgrid solution is competitive with the current price of electricity paid for by all consumers in the microgrid, which, as discussed in Section 2.3.1 and 2.3.2 can be heavily subsidised, especially in those rural areas where there is the most to gain from microgrid solutions.

The report seeks to inform the wider debate around efficient fringe-of-grid microgrid deployment by identifying and quantifying the effect of the policy and regulatory barriers identified above and in Section 2.3.2 on the efficient uptake of fringe-of-grid microgrids and SAPS.

2.3 Residual Cost Recovery and Intergenerational Equity

Residual costs can encourage uneconomic microgrid investment where they can be avoided by going off-grid. Even in situations where going off-grid represents the least cost supply option, such as for community microgrids at the end of a long, high cost to serve SWER line, transitioning to a microgrid may strand some upstream asset investments that were made in good faith and appropriately at the time.

Under the current regulatory framework, residual cost recovery of network investments occurs exclusively via grid connected customers over time. Customers who disconnect are able to avoid paying their share of fixed costs incurred on their behalf under current arrangements. This can lead to cross-subsidies, uneconomic bypass, is inconsistent with the ‘user pays’ principle and contributes towards intergenerational inequity.

Unaddressed, growth in microgrids, and to a lesser degree, distributed energy resources (DER), will increase inter-generational inequity, as future customers are left to pay more than their fair share of the fixed costs left behind. There is little information in the public domain in Australia or overseas regarding the scope, sizing and timing of the issue, or how it may be best minimised, and ultimately addressed.

This report seeks to inform national discussion of the issue by estimating the size, timing and scope of DER and microgrid driven residual cost avoidance and cross-subsidies across a range of potential industry and regulatory options for efficiently minimising them, including:

- progressively more cost reflective tariffs,
- establishment of a targeted SAPS tariff to minimise uneconomic bypass, and
- regulated and unregulated community microgrids at the fringe-of-grid.

The report did not consider the application of grid exit fees, where customers pay out their fair share of residual costs when exiting the grid. However, this may be of interest for future research.

3 Modelling Approach

3.1 Overview

As noted in the introduction, Energeia's behind-the-meter to National Electricity Market (NEM) modelling considers the uptake of three different types of micro grids:

- **Existing Individual Customer Stand Alone Power Systems**
- **New Connection Stand Alone Power Systems**
- **Fringe-of-grid Community Microgrids**

In addition, the modelling explored the concept of a new tariff for SAPS customers, known as the SAPS tariff. The SAPS tariff provides customers with a lower cost tariff which enables them to use the grid during non-network peak times for back-up purposes, allowing customers to reduce the size of DER systems and improve their reliability of supply compared to what they would otherwise experience with exiting the grid.

This study has been undertaken by Energeia as part of a larger modelling exercise of the energy system. The larger modelling exercise considered the impact of microgrids on the energy system along with a range of other customer behaviour with respect to DER and tariff adoption. The modelling of new connection SAPS was undertaken separately using consistent inputs and assumptions to the main, integrated model.

The modelling sought to address the impact of pricing reforms on the scale, timing and impacts of microgrids on customers and networks by developing forecasts of the uptake under various scenarios.

3.2 Microgrid Uptake

3.2.1 Existing Individual Customer SAPS

There are several emerging examples of individual customers choosing to adopt SAPS as an alternative to grid supply. For the most part, these customers are driven by environmental concerns and/or a need for greater resilience or grid independence as opposed to pure economic factors. However, the modelling considered uptake of individual customer SAPS only where it was economically rational for a customer to do so.

The modelling of SAPS uptake was undertaken using Energeia's agent based DER simulation platform which simulates the decisions of 6,000 agents with respect to DER uptake and operation, representing Australia's electricity customer base. Each agent, for each year of the modelling period, is presented with a range of potential options including tariff uptake, DER uptake and/or SAPS uptake. Agents only adopt SAPS where this represents the most economic outcome from the agent's perspective, given the prevailing tariff and technology cost environment. That is, the annualised cost of SAPS technology must be less than the annual bill the customer would otherwise receive from its retailer for any other tariff or tariff and technology combination.

3.2.2 SAPS Tariff Alternative

The concept of a grid integrated SAPS was also explored for existing individual customers via the introduction of an integrated SAPS tariff.

For the purposes of the modelling, the integrated SAPS tariff allowed the consumer to import or export from the grid during off-peak times, but did not allow the customer to consume any grid energy at all during network system peak events (five events per year across a four-hour period). The customer must therefore have sufficient DER to enable them to be fully self-sufficient during these times.

The integrated SAPS tariff is comprised of residual components only, which mirror the residual components of other cost reflective tariffs offered by the network. Energeia based its SAPS tariff on a Critical Peak Price structure, without the peak component, but a wide range of alternative structures are possible. For example, a SAPS tariff could be based on a volume-less structure, which might better support peer-to-peer trading.

For the purposes of the modelling, it is assumed that networks offer a 5% discount on this tariff compared to other cost reflective tariffs as an incentive to discourage inefficient microgrid uptake. This is consistent with the concept of a prudent discount, which transmission companies are allowed to offer under the National Electricity Rules where economic bypass occurs in order to keep other customers' costs as low as possible.

The SAPS tariff is offered on a voluntary opt-in basis and customers adopt it only where it is more cost effective to do so compared to going completely off-grid. To adopt the SAPS tariff, customers must be able to meet their energy demands (without behaviour change) during peak times via DER, thus requiring relatively large systems compared to standard integrated grid plus DER alternatives.

Ultimately, the modelling sought to identify to what extent the integrated SAPS tariff could reduce or defer off-grid SAPS uptake by individual customers.

3.2.3 Fringe-of-grid Community Microgrid Solutions

Increasingly, microgrid solutions are being investigated as cost effective alternatives to grid supply in high cost to supply rural and remote areas of the network. Community microgrids differ from individual customer SAPS in that they involve more than one premise, and may therefore involve more complex tariffs, regulatory and customer protection issues.

Two distinct options were considered for the modelling of fringe-of-grid community microgrid solutions[11]:

- **Unregulated Microgrids –** The first option represents the current status quo whereby a fringe-of-grid community may be taken off-grid by a third party and thus exit the National Electricity Market or South West Interconnected System (SWIS) for jurisdictional arrangements. The modelling assumes that only occurs where there is a commercial business case for the third party to provide such a service. That is, the cost of supplying the microgrid service is less than the amount paid by customers within that microgrid under current tariffs. The viability of this option is therefore strongly affected by the prevalence of subsidies within current tariff structures, particularly for rural customers, which may prevent cost effective microgrid solutions. For the purposes of this report, this option is referred to as an 'unregulated microgrid'.
- **Regulated Microgrids** – The second option represents a change in the regulatory environment which would allow fringe-of-grid microgrid solutions to emerge where they represent a lower cost solution from an economic perspective. This may occur via two separate pathways:
  - Firstly, where a network is required under the regulatory framework to implement microgrid solutions where they represent the lowest cost option
  - Alternatively, where a network is required to make available, to a third party, the full extent of the network savings that would be realised where that third party deployed a microgrid solution

  Both options involve regulatory complexities which are not further explored here. The model does not distinguish between the two pathways, assuming that they would both give rise to a microgrid solution where it reflects the lowest economic cost option.

  For the purposes of this report, this option is referred to as a regulated microgrid.

For both the unregulated and regulated microgrid approaches, the modelling seeks to identify to what extent current tariff structures and ambiguous regulatory arrangements act as a barrier to the otherwise cost effective implementation of off-grid microgrid solutions for fringe-of-grid community locations.

3.2.4 New Connection SAPS

For new connections, the upfront cost of a grid connection can provide an additional financial incentive for adopting a SAPS solution, which increases with distance from the grid. The modelling explored the timing and scope for SAPS solutions to emerge as more cost effective alternatives for sites with high connection costs. The modelling was limited to key new connection segments which were determined to be new remote farms and mines as examples of sites which generally cannot be relocated due to resource proximity.

[11] Fringe-of-grid community microgrids are referred to as 'microgrids' in this report, in contrast to 'SAPS'.

For the purposes of the modelling, the following ranges of new connections were considered:

- New farms between 25km and 49km from the grid consuming 25 MWh to 300 MWh per annum
- New mines between 10km and 500km from the grid consuming 100MWh to 10,000 MWh per annum

3.3 Scenarios

A set of six scenarios were developed by Energeia in close collaboration with the ENA and CSIRO for the purposes of both this study as well as a separate study addressing network tariff reform more broadly.

The scenarios were designed to vary progressively according to the timing, depth and sophistication of both network pricing and regulatory arrangements for SAPS and microgrids. Importantly, the macroeconomic settings in the model were kept constant across scenarios and only those levers able to be pulled by networks and/or regulators or policy makers were adjusted.

For the purposes of this study, the key differences between the scenarios relate to:

- The prevailing network tariff settings
- Availability of the SAPS tariff
- Regulatory settings for fringe-of-grid (unregulated or regulated)

The four key scenarios relevant to this report are described below:[12]

- **Scenario 1** – Represents the base case approach to network pricing arrangements, whereby the current structures 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.

  There is no SAPS tariff available under this scenario.

  For fringe-of-grid locations, networks are limited by the regulatory framework to the traditional centralised delivery model. Fringe-of-grid microgrids accordingly only emerge where an unregulated microgrid can provide customers with lower bills compared to prevailing tariffs.

- **Scenario 3** – Represents a further proactive increase in tariff assignment and uptake policies by networks whereby all customers are assigned to maximum demand tariffs in 2021 on an opt-out basis.

  The SAPS tariff is introduced on a voluntary opt-in basis from 2021. This SAPS tariff acts as an alternative and potentially more attractive option for customers who may otherwise go off-grid.

  For fringe-of-grid community microgrids, the settings are as per Scenario 1.

- **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. This scenario was run to test the impact of allocating revenue away from energy volume charges towards increased fixed charges.

  Scenario 3 (Adjusted) also includes an opt-in SAPS tariff from 2021 and is limited to unregulated fringe-of-grid microgrids as per Scenario 3.

- **Scenario 5** – Represents a move towards locational pricing incentives. Grid connected customers are transitioned to locational, dynamic pricing from 2021, and are offered an incentive to allow the network or a third-party aggregator to manage their DER for them instead.

  The SAPS tariff is introduced from 2021 as per Scenarios 3 and 4.

  The regulatory framework is adjusted from 2021 to ensure that a fringe-of-grid microgrid is deployed where this represents the lowest cost option as per Scenario 4.

[12] The full set of scenarios are described in: *Network Transformation Roadmap: Work Package 5 – Pricing and Behavioural Enablers Network Pricing and Incentives Reform*, Energeia, August 2016

4 Modelling Results

The results below present the findings of Energeia's modelling at the NEM level over the period to 2050.

It should be noted that the results are presented for Scenario 1, Scenario 3, Scenario 3 (Adjusted) and Scenario 5. Scenario 2 has been excluded as there is no material difference between this scenario and Scenario 1 with respect to microgrid uptake. Similarly, there is no material difference between Scenarios 4, 5 and 6.

4.1 Existing Individual Customers

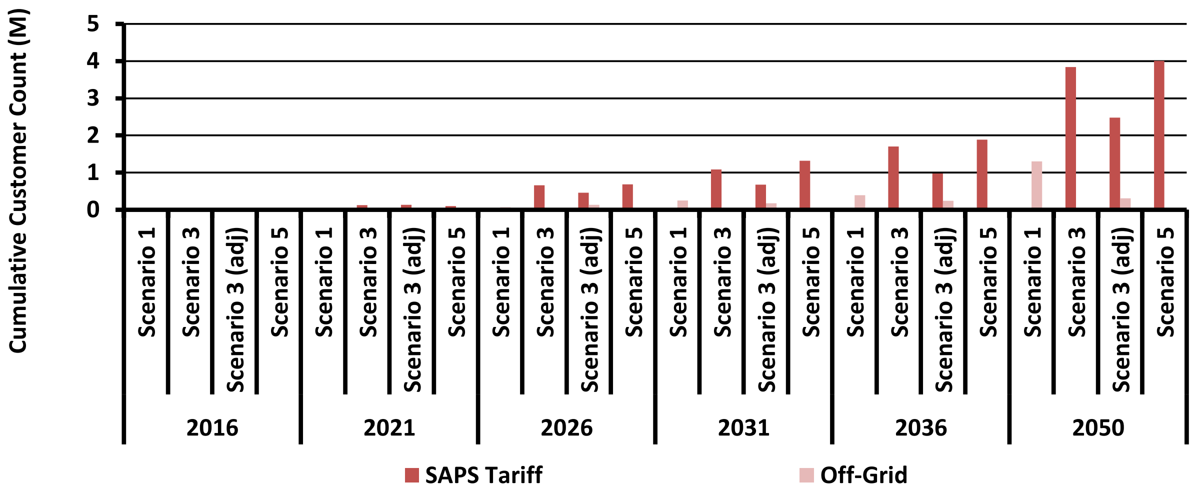
The following sections present and discuss the key modelling results for existing customer adoption of SAPS.

4.1.1 Existing Individual Customer SAPS Uptake

The number of existing residential and commercial customers adopting SAPS is shown by type (integrated SAPS or off-grid SAPS) and scenario in Figure 6 and Figure 7 respectively.

Across all scenarios, there are very few residential SAPS until 2026, when adoption starts to rise in Scenario 3, Scenario 3 (Adjusted) and Scenario 5. Scenario 3 and Scenario 5 show about the same level of residential SAPS. Scenario 3 (Adjusted), with higher fixed costs, shows just over half the level of uptake compared to other scenarios for most of the time, rising to two thirds by 2050.

Figure 6 – Cumulative Residential Customers with SAPS to 2050 by Scenario

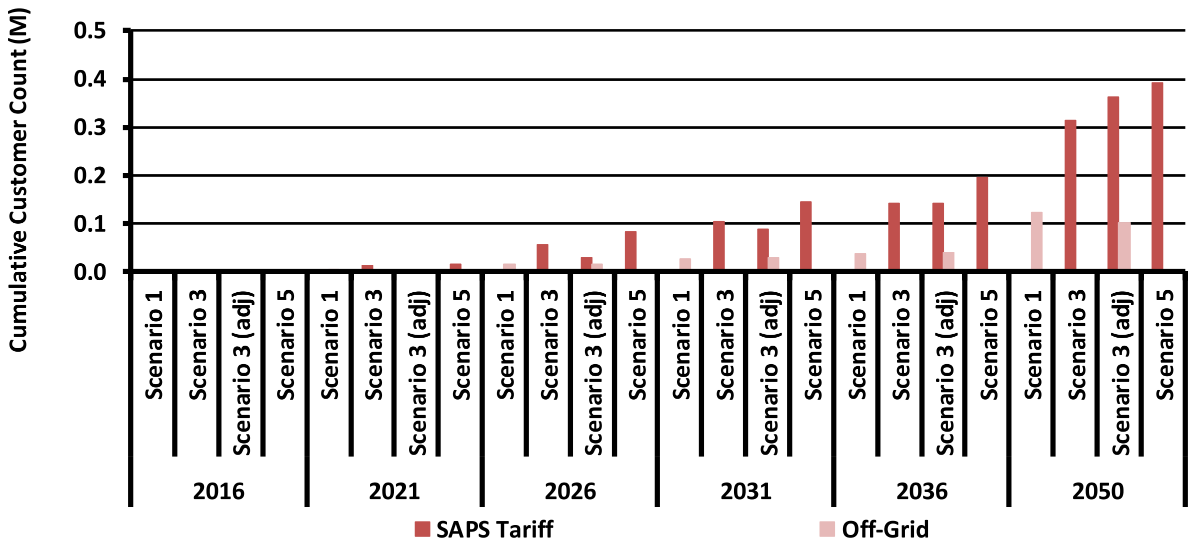


Source: Energeia

Off-grid SAPS do not appear until 2031 under Scenario 1 and 3 (Adjusted), with Scenario 1 only slightly higher at this stage. However, off-grid SAPS under Scenario 1 start to ramp up much faster than Scenario 3 (Adjusted) after 2036, due to the dampening effect of restructured network prices under Scenario 3 (Adjusted). By 2050, the modelling shows around 1.25 million customers exiting the grid under Scenario 1, compared to around 0.25 million under Scenario 3 (Adjusted) and virtually none under Scenarios 3 and 5.

The modelling results for commercial customers are similar to the residential customer results. Key differences shown in Figure 7 include similar levels of off-grid SAPS between Scenarios 1 and Scenario 3 (Adjusted), and relatively higher levels of integrated SAPS tariff adoption under Scenario 3 (Adjusted), due to the relatively greater savings from solar PV on commercial demand during peak periods compared to the residential sector.

Figure 7 – Cumulative Business Customers with SAPS to 2050 by Scenario

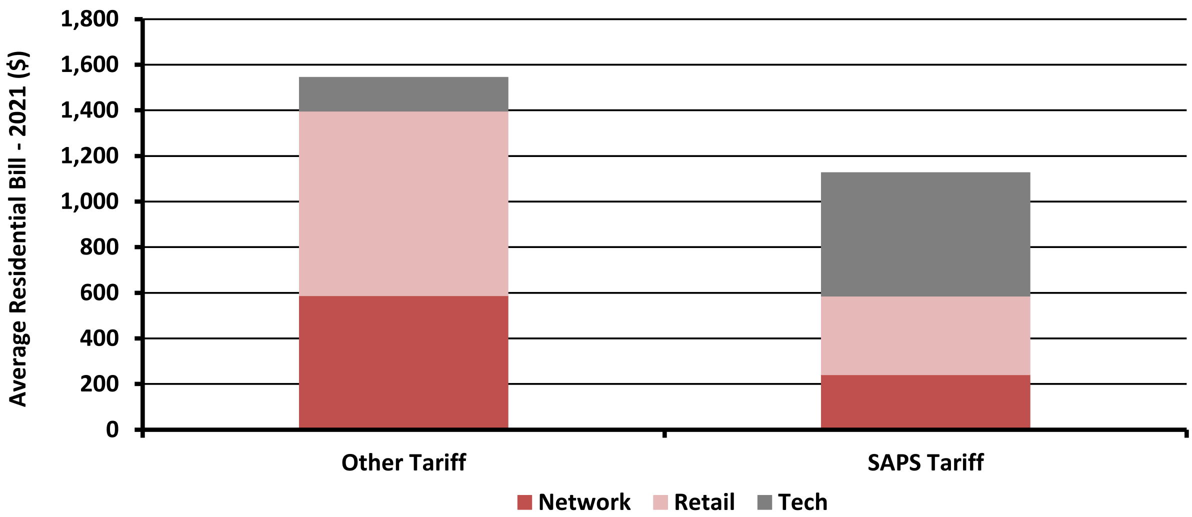


Source: Energeia

Based on the above results, Energeia's key conclusions are that around 10% of residential customers and a smaller percentage of commercial customers will adopt off-grid SAPS and no longer rely on the grid for any imported energy under the base case.

Offering a SAPS tariff (Scenario 3 to 5) changes the decision of customers adopting off-grid SAPS as a result of the attractive offering of the integrated SAPS tariff. Figure 8 below demonstrates the attractiveness of the SAPS tariff where, on average, customers are able to reduce their network and retail bill significantly through the uptake of DER technology, compared to non-SAPS alternatives.

Figure 8 – Average Residential Bill Benefits (Scenario 3, 2021)



Source: Energeia

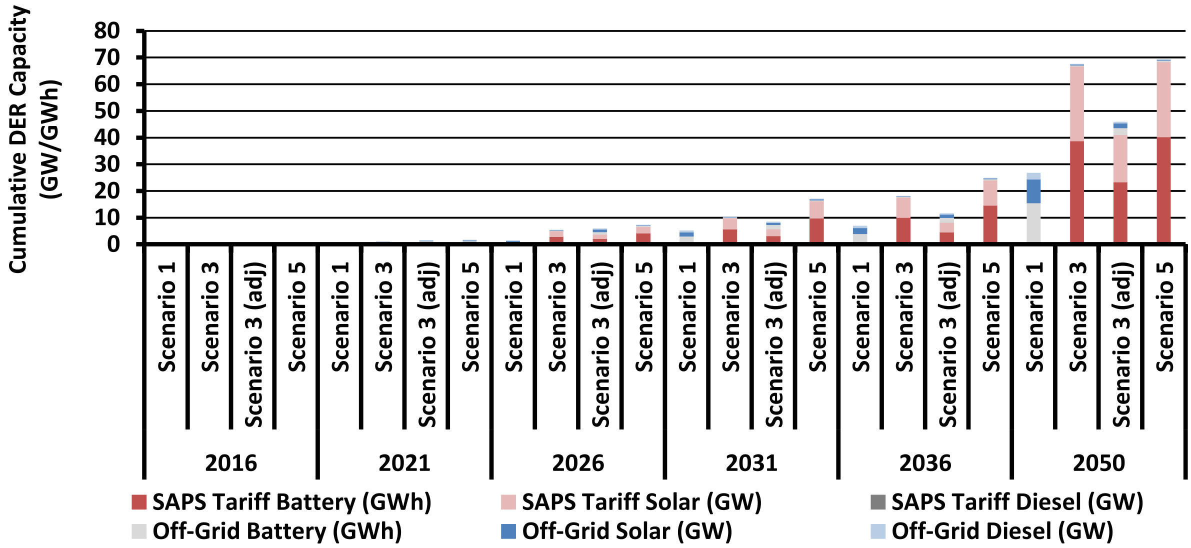
Scenario 3 (Adjusted) restructures tariffs by 2021 before customers are transitioned to cost reflective demand tariffs on an opt-out basis. This reduces SAPS tariff uptake overall, but increase customers going adopting off-grid SAPS due to the relatively high fixed charge, albeit at substantially lower levels than under the base case.

4.1.2 Existing SAPS Investment in DER

Figure 9 displays DER investment patterns by scenario and type of SAPS to 2050 for residential SAPS customers. DER investment under Scenario 1 is relatively low due to off-grid SAPS representing around 10% of customers, compared to the 25-40% of customers represented by the other key scenarios (both integrated and off-grid SAPS). Investment in solar PV capacity for SAPS in Scenarios 3, 3 (Adjusted) and 5 is around the 8 GW to 14 GW level by 2050, while storage varies between 20 GWh and 40 GWh to 2050.

Interestingly, diesel capacity is much higher for off-grid SAPS at around 15% of total capacity, reflecting the more onerous operating environment, when independent of the centralised network. Under the integrated SAPS tariff, microgrids only need to operate eight hours off-grid at a time during the network peak, which leads to a smaller SAPS compared to those needed to supply a customer's own annual requirement when entirely off-grid.

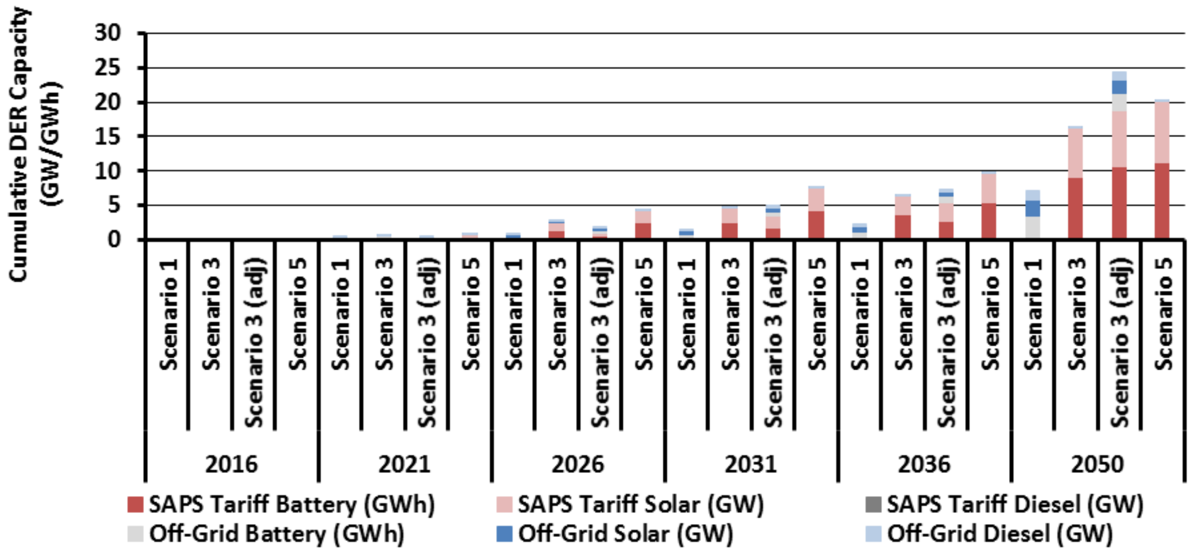
Figure 9 – Cumulative DER Capacity of Residential Customers with SAPS to 2050 by Scenario



Source: Energeia

The modelling again revealed differences between residential and commercial results, which are displayed in Figure 10. The main difference is found in Scenario 3 (Adjusted), which results in more business customer adoption of DER for both integrated and off-grid SAPS by 2050. The level of diesel capacity required to power a business customer is also higher than for residential at around 25% of total capacity.

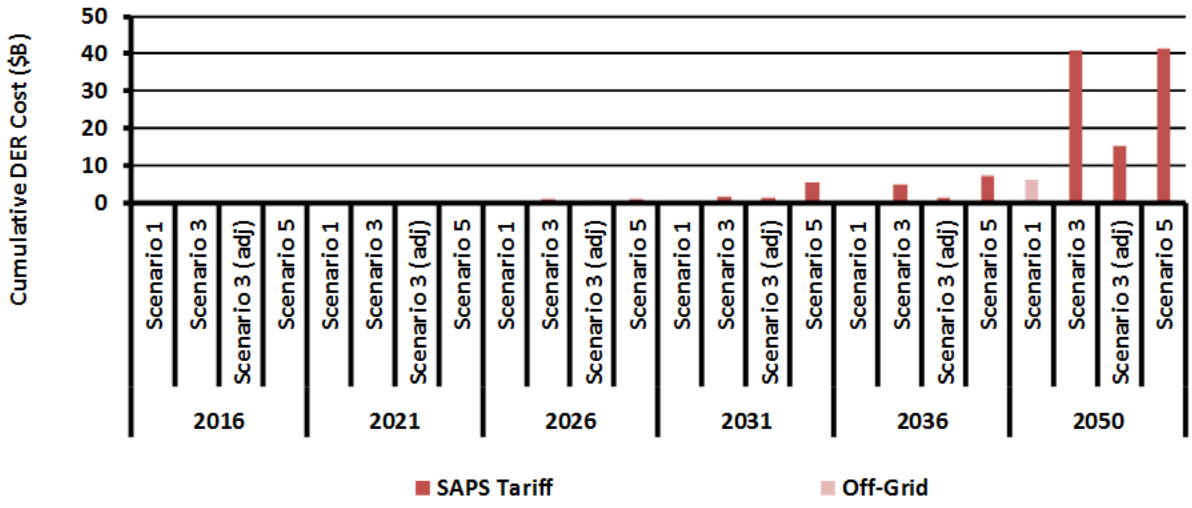
Figure 10 – Cumulative DER Capacity of Business Customers with SAPS to 2050 by Scenario



Source: Energeia

Figure 11 and Figure 12 display the total SAPS expenditure by type and scenario to 2050. It largely mirrors the capacity results.

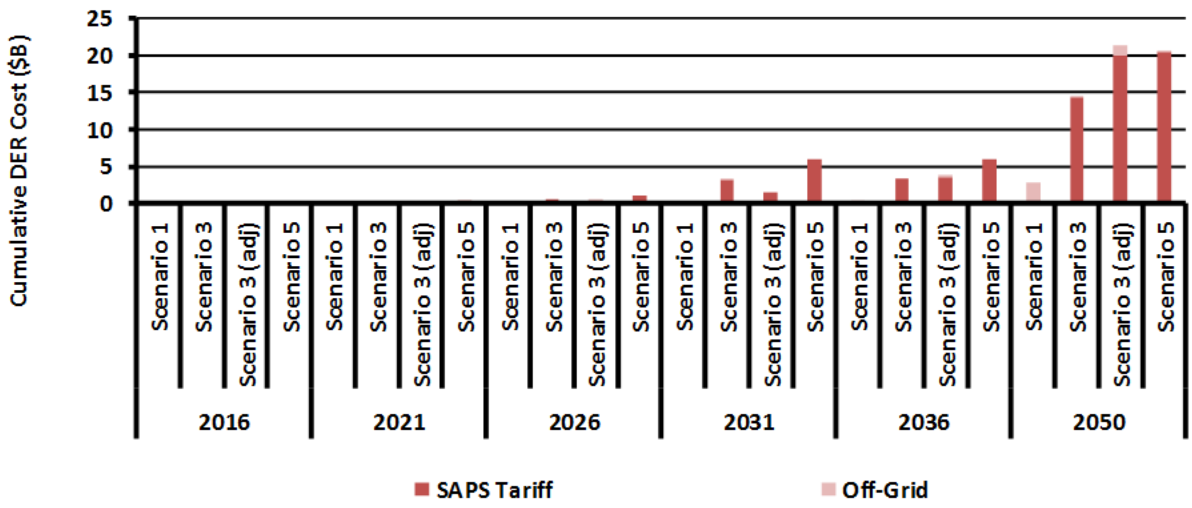
Figure 11 – Cumulative Residential Customer Expenditure on SAPS to 2050 by Scenario



Source: Energeia

One of the key findings from the modelling is the impact of the restructured Scenario 3 (Adjusted) tariffs on reducing cumulative DER uptake and costs. This has a dramatic effect by 2050 under Scenario 3 (Adjusted), which shows around 70% less DER costs than Scenario 3. The restructuring has a lower effect on business customers due to the relatively greater ability of solar PV to reduce commercial customer's peak demand.

Figure 12 – Cumulative Business Customer Expenditure on SAPS to 2050 by Scenario



Source: Energeia

In summary, direct investment in SAPS is minimised under Scenario 1 across all customer types, however as discussed further below, it does not result in the lowest overall costs for grid connected customers due to the impact of additional residual cost recovery on their bills over time.

Offering an alternative to off-grid SAPs in the form of an integrated SAPS tariff significantly increases SAPS investment under Scenarios 3, Scenario 3 (Adjusted) and Scenario 5. However, under Scenario 3 (Adjusted), where tariffs are restructured to limit cross-subsidies, residential SAPS investment is reduced by more than 50% compared to Scenarios 3 (Adjusted) and 5.

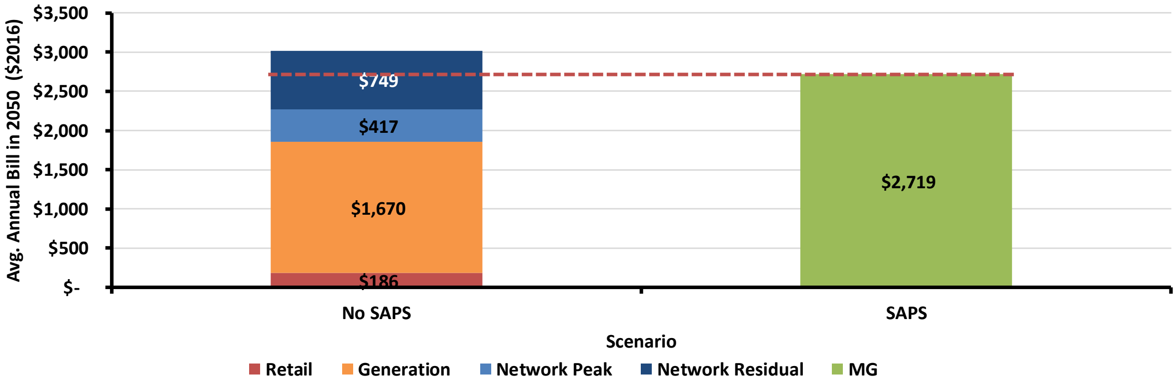
Whether the higher DER investment seen in Scenarios 3-5 leads to lower overall customer costs depends on their impact on network and wholesale market costs, which in turn depends on their timing, sizing, location and mode of operation. These effects are discussed further below.

4.1.3 Customer Impacts

Energeia's analysis of the effects of keeping customers connected that would otherwise disconnect from the grid through a SAPS tariff has found that this is likely to keep tariffs down by 4% relative to the base case by 2050. This is because each one of the 1.4 million exiting customer's $750 per year average residual network charges must be covered by the remaining 12.6 million customers, or around $1 billion per annum in higher bills.

This is illustrated in Figure 13, in terms of average bills. The example shows that customer bills include a residual cost component that makes it appear to customers going off-grid that their solution is cost-effective. This leads to a higher cost solution being adopted, which increases overall community costs, including off-grid SAPS customers, but also results in the $749 being reallocated to remaining customers, increasing their bills.

Figure 13 – Average Grid Connected versus Off-grid SAPS Customer Bill



Source: CSIRO, Energeia

4.1.4 Economic Impacts

The above modelling results also show that a SAPS solution may actually represent a higher forward looking cost to serve solution than the no SAPS solution, but would still be favoured by the customer in terms of avoiding residual costs. Investment in microgrids therefore increases total economic costs for the energy system by around $420 million ($2016) per year by 2050, or $300 per off-grid customer as illustrated in Figure 13.

Accordingly, Energeia estimates that the net present value of implementing a SAPS tariff in 2021 is $1.2 billion relative to Scenario 1. This figure excludes the network and other industry costs associated with integrating and supporting 30% of customers adopting connected SAPS over the period.

4.2 Fringe-of-grid Microgrids

Unsurprisingly, no unregulated fringe-of-grid community microgrids were identified anywhere in the NEM or SWIS under either Scenario 1 or Scenario 2. Under these scenarios, microgrids are only viable where they become cost competitive with prevailing, often heavily subsidised, existing tariffs.

However, the lack of viable regulated microgrids under Scenarios 3 to 6 was unexpected. For these scenarios, fringe-of-grid microgrids were expected to emerge in the most remote, highest cost to serve locations as microgrid solution costs fell over time and became the lowest cost alternative to traditional supply options.

Instead, Energeia's modelling found that Australia's moderately sized communities at the fringe-of-grid are generally unable to be cost effectively served by a microgrid even by 2050 without specific local extenuating circumstances, e.g. significantly lower than average levels of reliability or significantly higher than average costs to serve. These must be determined on a case by case basis, rather than systematically.

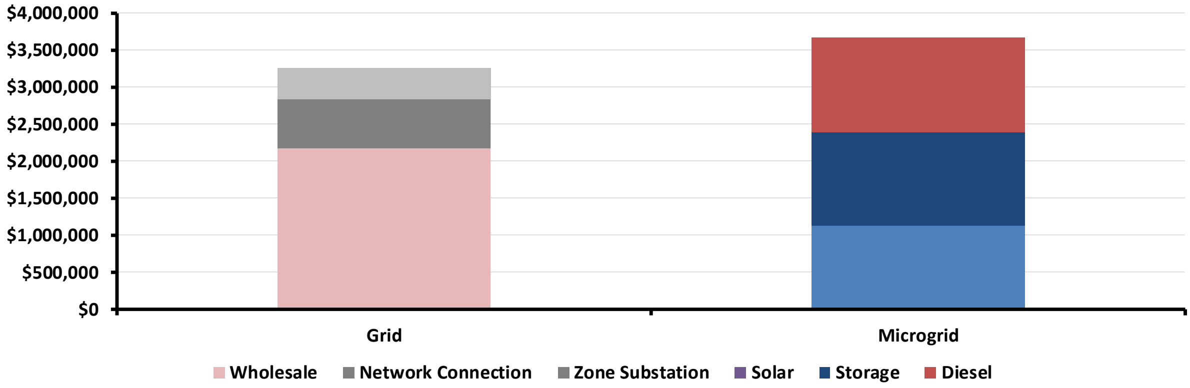
This result is due to a complex interplay of factors and assumptions in the Energeia modelling, including:

- rising diesel prices linked to oil and carbon price increases,
- the timing of grid infrastructure replacement, which is expected to mainly occur over the next twenty years, before microgrid technology is sufficiently low cost, or
- CO2 price driven increases in wholesale market cost are sufficiently high enough.

Diesel prices, including the impact of oil price and carbon prices needed to meet Australia's climate change commitments over time, increase to $580 per MWh by 2050, while grid prices in 2050 are around $165 per MWh. This leads to optimal microgrid solutions using less and less diesel over time, but it never becomes cost effective to run community microgrids without it.

Figure 14 shows the modelling results from the fringe-of-grid community in NSW in 2042 that came the closest in our modelling to becoming a cost effective microgrid. Sensitivity testing revealed that either a significantly higher cost of replacement or significantly lower level of reliability than the averages assumed in the modelling[13] would have made this community microgrid economic.

Figure 14 – Annual Costs of Rural NSW Community Microgrid vs. the Grid in 2042 (Case Study)



Source: Energeia, CSIRO, DNSPs, AEMO

While the above case study identifies how key drivers can make one of the most prospective examples cost effective by 2042, it is important to keep in mind that cost effectiveness depends on the costs of a microgrid and the timing of the network investment. For the modelling undertaken, key candidate fringe-of-grid communities tended to face a replacement driver prior to the microgrid becoming cost effective. That is, by the time a microgrid became cost competitive, the replacement driver no longer existed.

Finally, as foreshadowed under the modelling limitations listed in Section 1.5, it is important to note that the fringe-of-grid community microgrid modelling reported above was limited in several critical aspects including consideration of 5 MW and above communities (around 500-1,000 residents plus local businesses), use of a system rather than locational LRMC value, and the lack of site specific reliability performance.

There are likely to be a number of smaller parts of the network (feeder level or below), or those with higher than average costs of replacement or poorer reliability, which are likely to be cost effective over the period to 2050. It has been estimated by Energeia in previous work that the number of communities that this may represent is in the order of 40 and therefore relatively insignificant in the context of overall grid impacts.

4.3 New Connections SAPS

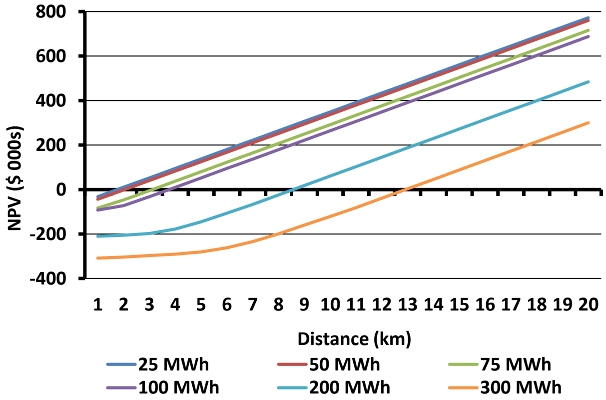
Energeia's modelling of SAPS uptake by key new connection segments found that even the smallest (100 MWh) new mines up to 500km away from the nearest line are likely to connect to the grid throughout the study period. The story for agricultural and other business customers was quite different, with the modelling showing the smallest (25 MWh) new farms sites being better off as a SAPS today, if they were more than 1 km from the

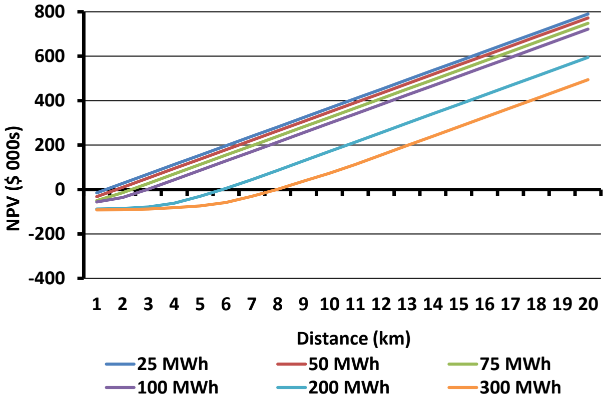
[13] Averages were used due to the lack of available asset specific data.

existing grid. Even the largest farms (300 MWh) modelled were found to be better off on a SAPS by 2020 if at least 8 km away from the grid, with the breakeven distance dropping every year.

Figure 15 displays the net present value results for new farm SAPS ranging in size from small farms (25 MWh annual energy consumption) to large farms (300 MWh annual energy consumption) depending on distance from the grid. The net present value for these connections show a "kink" as a function of annual consumption due to the way that new connection pricing works, which effectively offsets upstream connection costs as a function of the total network bill, up to the value of the network bill.

Figure 15 – Avg. NPVs of New Farm SAPS Connections by Distance in 2016 (Left) and 2020 (Right)





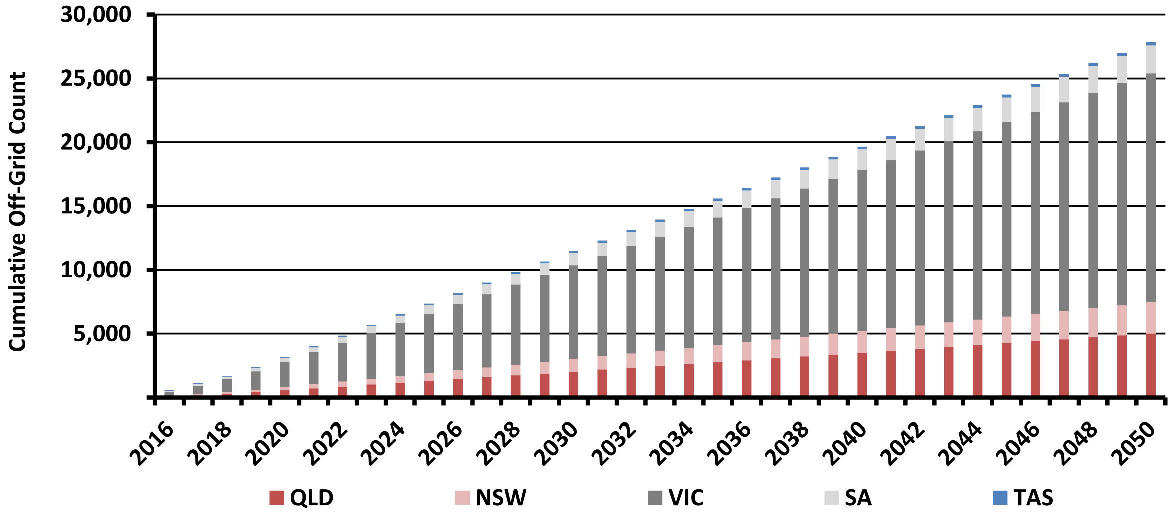
Source: CSIRO, DNSPs and Energeia

The mining results showed no new mining SAPS up to the modelled 500 km limit and therefore no material differences between the scenarios with respect to new connection SAPS. The following section therefore focus on the modelling results for new farm SAPS to 2050 under Scenario 5.

4.3.1 New Rural Farm SAPS

Figure 16 displays Energeia's forecast for new farm SAPS by state and year to 2050. The modelling results largely reflect the number of new farms forecast for each state. The results show up to 27,000 total new farm SAPS over the period to 2050 Australia wide.

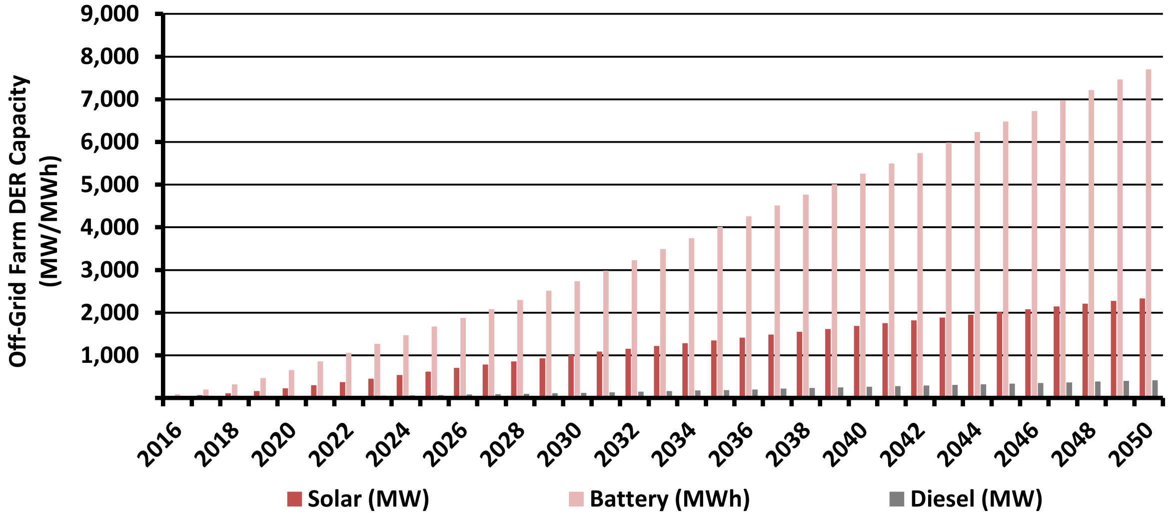
Figure 16 –Cumulative New Farm SAPS Connections by State and Year



Source: CSIRO, DNSPs and Energeia

Figure 17 presents Energeia's forecast investment in solar PV, battery storage and diesel generation capacity by new farm SAPS over the period to 2050. The relative contribution of battery storage increases over time, due to both declines in technology prices and the effect of carbon on the cost of diesel generation driving down reliance on diesel.

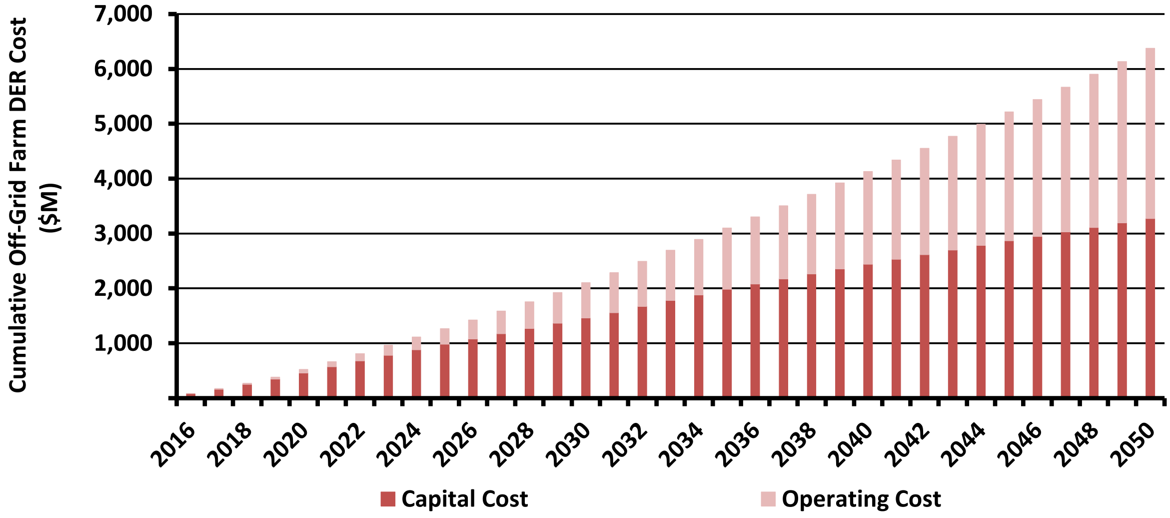
Figure 17 – Cumulative DER Installed by New Farm SAPS Connections DER Technology



Source: CSIRO, DNSPs and Energeia

Figure 18 displays the forecast cumulative SAPS operational (opex) and capital expenditure (capex) by year to 2050. Capex rises with new SAPS and cumulative opex continues to grow until the end of the modelling period.

Figure 18 – Cumulative DER Investment by New Remote Farms adopting a SAPS to 2035 by Type



Source: CSIRO, DNSPs and Energeia

In summary, Energeia's modelling of new connections highlights the key roles that technology prices, carbon prices, distance and annual consumption play in the optimal deployment of SAPS. By 2020, most new farms connections greater than 3 km from the grid will represent cost effective SAPS opportunities. Larger, irrigation based agriculture will need to be more than 8 km from the grid in order for a SAPS to be viable.

5 Conclusions and Recommendations

5.1 Tariff Reforms

In the absence of any tariff reforms, Energeia's modelling forecasts that 10% of customers will uneconomically leave the grid, mainly over the 2031 to 2050 timeframe.

Scenarios 3-5 show that a new SAPS tariff for the emerging SAPS class of customers could virtually eliminate customers uneconomically going off-grid by offering them a more competitive offer. The modelling shows that the SAPS tariff needs to be appropriately designed to avoid everyone recharging their batteries at the same time at the start of the off-peak period. This is consistent with findings in our previous report, recommending that electricity distributors continue to refine cost reflective tariff mechanisms generally so as to limit cross subsidies and the creation of new peaks from battery storage.

Based on the above findings and conclusions, Energeia recommends that Australian electricity distributors review their current tariff designs to ensure that they are resilient to battery operation.

5.2 New SAPS Tariffs for Existing Connections

Energeia's modelling shows that residential and business customers are adopting microgrids due in part to the savings that can be realised from avoided residual costs. The modelling showed that under the base case, approximately $1 billion of residual costs per year in 2050 would be avoided by customers going off-grid, which would be transferred to remaining customers, increasing the cost of electricity for all grid connected customers.

The modelling also shows that a voluntary, integrated SAPS tariff is effective at mitigating the potential cost transfer from disconnecting to connected customers. Further, given the high levels of SAPS tariff adoption across Scenarios 3-5, it is likely that the SAPS structure as modelled could be further optimised to improve equity between groups, while still minimising uneconomic customer disconnection.

Energeia therefore recommends that a trial of an integrated SAPS tariff is undertaken by electricity distributors which are most likely to benefit from its availability (i.e. South Australia, Queensland and Victoria). This will allow these electricity distributors and their stakeholders to gain sufficient experience with the tariff before it is expanded more broadly.

5.3 Fringe-of-grid Microgrid Solutions

The rising cost of diesel, exacerbated by carbon price increases, resulted in no viable fringe-of-grid community microgrids. However, modelling limitations mean that community microgrids could still emerge where there are significant reliability benefits, or where construction costs are significantly higher than average for the network.

Energeia therefore recommends that electricity distributors work with regulators, policymakers, retailers and other industry stakeholders to remove the key technical, institutional regulatory and legal barriers from the efficient deployment of microgrids at the fringe-of-grid. Industry should also investigate the cost effectiveness of transitioning long-rural categorised SWER feeders to microgrid technology.

5.4 SAPS Enabling Services

The concept of the grid-integrated SAPS envisioned in Scenario 5 implies a network capability to integrate with SAPS systems directly or via one or more intermediary platforms, ensuring these are utilised most effectively during the peak periods of the year. There is a lesser integration requirement under Scenarios 3 and 3 (Adjusted), which still requires signalling of the 4-5 critical peak days of the year when the SAPS is required to operate independently as per the terms of the tariff.

Technical and commercial arrangements will therefore be necessary to effectively establish the SAP tariff. The SAPS tariff pilots recommended above would help to establish the role of the distribution network and to identify the key technical integration requirements and potential solutions and their associated costs and benefits. Delaying the grid's competitive response to going off-grid beyond this timeframe appears likely to see a significant rise in customers going off-grid.

5.5 Policy and Regulatory Reforms

Each of the above recommendations requires the support of policymakers and regulators to progress:

- Some require specific reforms to the current arrangements, such as removing barriers to transitioning connected customers to a lower-cost, higher-performing microgrid solution.
- The creation, piloting, and ultimately offering of a SAPS network tariff may also need a regulatory reform due to the five-year fixed nature of the TSS.
- Finally, the costs associated with DNSPs establishing SAPS integration services will need to be approved during the next five-year regulatory cycle to ensure the capability is up and running in time for the critical post 2031 period.

The influence of current diesel tax rebates and future carbon pricing on the cost effectiveness of microgrid solutions raises questions as to how these policy mechanisms will apply to rural and remote SAPS and microgrids. Clarification of Australia's carbon pricing scheme's operation with respect to fringe-of-grid SAPS and microgrids would give greater certainty to those considering these investments.