The proposed Latrobe Valley Microgrid (LVM) will demonstrate how local distributed energy resources (DERs) can be incorporated into a Local Energy Market (LEM) to improve economic and social outcomes for participants and support a more efficient grid. The LVM will implement LO3 Energy’s blockchain based Local Energy Market (LEM) platform and smart metering devices to bind participants together in an Internet of Things (IoT) digital market place, enabling participants to buy and sell locally produced renewable electricity using an eBay style auction mechanism.

To support the implementation of the LVM project this feasibility analysis was completed to test the economic benefits to consumers and prosumers potentially available from participating in a LEM. The modelling undertaken for the feasibility analysis demonstrated the potential for a LEM to deliver financial benefits to consumers. If implemented under existing market arrangements the modelling showed that consumers could potentially save between 6% and 12% on their energy purchases by making those purchases from the LEM, depending on their bidding strategies, compared to energy purchases they currently make at the retail price. Prosumers could potentially gain between 18% and 37% compared to selling their surplus electricity to their retailer at the existing Feed in Tariff (FiT).

A key finding from the feasibility analysis is that a LEM could provide a compelling proposition for consumers who value renewable electricity and supporting their local communities. The LEM could allow consumers and prosumers to achieve their environmental and social objectives without increasing their current energy bills and perhaps even lowering them.

LO3 Energy’s long term vision is for the LEM is to provide a market platform for transacting a range of different energy services, including peer to peer energy trading, demand response and virtual power plants, in a way that will allow the LEM to operate as a true market, not one necessarily controlled by a single retail intermediary. The project partners commissioned King and Wood Mallesons (KWM) to assist in identifying the potential regulatory barriers to achieving this vision. Their findings and full recommendations are set out in a separate report accompanying the feasibility study.

One of KWMs most far reaching recommendations for supporting future development of the LEM vision is to implement the concept of Multiple Trading Relationships (MTR) in the National Electricity Market (NEM). They propose the creation of a new Market Participant classification or classifications for ‘New Energy Service Providers’, covering services such as demand management, aggregations of DERs (also known as Virtual Power Plants or VPPs) and peer-to-peer energy trading. This would also create a new framework allowing customers to enter into contracts with multiple energy service providers at their connection point. It is likely this recommendation would require a proof of concept trial, supported by a regulatory sandbox. The LVM project provides a good opportunity for a regulatory sandbox to be implemented.

This report may be valuable for regulators, retailers, consumer advocacy groups and potential participants in a Local Energy Marketplace, or the Latrobe Valley Microgrid in particular.
Role of ARENA

This project received funding from ARENA as part of ARENA’s Advancing Renewables Program. The views expressed herein are not necessarily the views of the Australian Government, and the Australian Government does not accept responsibility for any information or advice contained herein.

Role of AusNet Services

Connection of distributed energy resources, particularly residential solar is changing both the magnitude and direction of power flows on AusNet Services’ network. To ready the grid for a high penetration of Distributed Energy Resources (DERs) in future, AusNet Services welcomes innovation within its network and is currently supporting a number of Australian Renewable Energy Agency (ARENA) projects with the goal of:

- Better customer satisfaction through an optimised renewables connection policy
- Improved stakeholder visibility of connected DERs and their production / hosting capacity for all stakeholders
- Enhancing customer value and network efficiency through maximisation of DER participation on our network using network-DER optimisation activities
- Extended network service market offerings for customer DER within the evolving regulatory framework
- Trialling time-of-use and locational pricing in areas where there may be economic benefit from the provision of network services

AusNet Services made a financial commitment of $100,000 to the Latrobe Valley Microgrid (LVM) feasibility study and has supported the project with a high-level review of proposed embedded generation connection applications at participant sites.

Any views represented, or recommendations made, within this report are not those of AusNet Services.

If this project progresses to the implementation phase, it will adhere to AusNet Services’ existing embedded generation connection application process, policies and fees accordingly.

Role of King and Wood Mallesons

While King and Wood Mallesons (KWM) prepared the legal and regulatory report set out in Appendix I, this feasibility assessment (including its regulatory recommendations) has been prepared separately by LO3 Energy without the input of KWM and does not therefore represent KWM views.
# TABLE OF CONTENTS

- **PROJECT OVERVIEW** ........................................................................................................... 2
- **ROLE OF KEY STAKEHOLDERS** .......................................................................................... 3
- **TABLE OF CONTENTS** ......................................................................................................... 4

## 1 EXECUTIVE SUMMARY ........................................................................................................ 7
  1.1 **PROJECT OBJECTIVE** ...................................................................................................... 7
  1.2 **RECRUITMENT OF FEASIBILITY PARTICIPANTS** .............................................................. 7
  1.3 **COMMERCIAL FEASIBILITY ANALYSIS** ......................................................................... 8
  1.4 **RESULTS** .......................................................................................................................... 9
      1.4.1 **Scenario 1** .................................................................................................................. 9
      1.4.2 **Scenario 2** .................................................................................................................. 10
      1.4.3 **Scenario 3** .................................................................................................................. 11
  1.5 **REGULATORY FEASIBILITY ANALYSIS** ........................................................................ 11
      1.5.1 **Recommendations** .................................................................................................... 11

## 2 THE LATROBE VALLEY MICROGRID .................................................................................... 13

## 3 BACKGROUND .................................................................................................................... 13
  3.1 **THE LATROBE VALLEY** ................................................................................................ 13
  3.2 **ENERGY MARKET CONTEXT** ......................................................................................... 14

## 4 ADDRESSING THE MARKET CHALLENGES – LEM PLATFORM .......................................... 16
  4.1.1 **More Competitive Retail Markets** ................................................................................ 16
  4.1.2 **More Competitive Wholesale Markets** ........................................................................ 16
  4.1.3 **A More Efficient Grid** ................................................................................................ 17
  4.1.4 **Locational Marginal Pricing** ....................................................................................... 18
  4.2 **TransActiveGrid LOCAL ENERGY MARKETPLACE PLATFORM** .................................... 19
      4.2.1 **Cloud Architecture** .................................................................................................. 21
      4.2.2 **Local Energy Marketplace** ....................................................................................... 22
      4.2.3 **Billing and Settlement** ............................................................................................ 23
      4.2.4 **TransActiveGrid Element** ...................................................................................... 23
      4.2.5 **Security** .................................................................................................................. 24
      4.2.6 **Supplementary Documentation** ................................................................................ 24
      4.2.7 **Support for Ongoing Operation and Maintenance** ...................................................... 24
      4.2.8 **Data Partner Integration** ......................................................................................... 24
      4.2.9 **Member Interfaces** .................................................................................................. 25
  4.3 **LATROBE VALLEY MICROGRID DISTRIBUTION NETWORK** ......................................... 28
      4.3.1 **Current Capacity and Solar Penetration** .................................................................... 28
  4.4 **FEASIBILITY STUDY PARTICIPANTS** ............................................................................ 29
      4.4.1 **Recruitment** ............................................................................................................. 29
      4.4.2 **Lessons Learned** ....................................................................................................... 31
  4.5 **SOLAR PROPOSALS** ....................................................................................................... 32
  4.6 **ENVIRONMENTAL UPGRADE FINANCE** ................................................................. 33
  4.7 **COMMUNITY SENTIMENT SURVEY** ............................................................................. 34
5 COMMERCIAL FEASIBILITY .................................................................................................................. 38
5.1 CONCEPTUAL FRAMEWORK ............................................................................................................. 38
  5.1.1 The Scenarios ................................................................................................................................. 41
5.2 MODELLING ASSUMPTIONS ............................................................................................................... 44
  5.2.1 Data Characteristics ....................................................................................................................... 44
  5.2.2 Solar Generation Assumptions ...................................................................................................... 45
  5.2.3 Cost of Participation in the LEM ................................................................................................... 46
  5.2.4 Data Analysis ............................................................................................................................... 47
5.3 MODELLING RESULTS ....................................................................................................................... 48
  5.3.1 Counterfactual Analysis .................................................................................................................. 48
  5.3.2 Scenario 1 Results - All Participants ............................................................................................. 50
  5.3.3 Scenario 2 Results - All Participants ............................................................................................. 53
  5.3.4 Scenario 3 Results - All Participants ............................................................................................. 56
5.4 A DEEPER LOOK INTO THE VALUE PROPOSITION FOR CUSTOMERS ..................................... 59
  5.4.1 Farms ........................................................................................................................................... 59
  5.4.2 Commercial Customers ............................................................................................................... 60
  5.4.3 Residential Customers ............................................................................................................... 62
  5.4.4 Distribution Network Service Provider ....................................................................................... 62
  5.4.5 Retailer ......................................................................................................................................... 63
6 LEGAL AND REGULATORY FEASIBILITY ...................................................................................... 65
  6.1.1 Wholesale Market Arrangements .................................................................................................. 65
  6.1.2 Retail Market Arrangements ........................................................................................................ 67
  6.1.3 Retail Pricing ............................................................................................................................... 69
  6.1.4 Network Charging in More Detail ................................................................................................ 69
  6.2 REGULATORY BARRIERS TO THE LEM PLATFORM SERVICES ....................................... 71
  6.2.1 Peer to Peer Energy Trading ....................................................................................................... 71
  6.2.2 Retail Market .............................................................................................................................. 72
  6.2.3 Network Charging ....................................................................................................................... 73
  6.2.4 Access to Wholesale Energy and Ancillary Services Market ...................................................... 73
  6.3 CURRENT REGULATORY REFORM PROCESSES .............................................................. 75
  6.3.1 Retail Market .............................................................................................................................. 75
  6.3.2 Wholesale and Ancillary Services Market .................................................................................... 76
  6.3.3 Distribution System Operator Model ............................................................................................. 77
  6.3.4 Data Access .................................................................................................................................. 78
7 RECOMMENDATIONS FOR FURTHER WORK .............................................................................. 79
  7.1 RECOMMENDATION 1 ......................................................................................................................... 79
  7.2 RECOMMENDATION 2 ......................................................................................................................... 79
  7.3 RECOMMENDATION 3 ......................................................................................................................... 80
  7.4 RECOMMENDATION 4 ......................................................................................................................... 80
  7.5 RECOMMENDATION 5 ......................................................................................................................... 80
  7.6 RECOMMENDATION 6 ......................................................................................................................... 80
  7.7 RECOMMENDATION 7 ......................................................................................................................... 81
APPENDIX A: SOLAR PROPOSALS TECHNICAL DETAILS .......................................................... 82
APPENDIX B: CURRENT EXPENDITURE AND TARIFF ANALYSIS ........................................ 90
APPENDIX C: DETAILED SCENARIO 1 LEM RESULTS ............................................................ 93
APPENDIX D: DETAILED SCENARIO 2 LEM RESULTS ............................................................ 95
APPENDIX E: DETAILED SCENARIO 3 LEM RESULTS ............................................................ 97
APPENDIX F: SOLAR GENERATION DATA .............................................................................. 99
    EXISTING SOLAR ........................................................................................................... 99
    PROPOSED SOLAR ....................................................................................................... 101
APPENDIX G: LEM RESULTS FOR EXISTING SOLAR ONLY .................................................... 103
    RESULTS OF SCENARIO 1 – EXISTING SOLAR ONLY ...................................................... 103
    RESULTS OF SCENARIO 2 – EXISTING SOLAR ONLY ...................................................... 106
    RESULTS OF SCENARIO 3 – EXISTING SOLAR ONLY ...................................................... 109
APPENDIX H: LVM124 DETAILED TARIFF SUMMARY ............................................................ 112
APPENDIX I: KING AND WOOD MALLESONS REGULATORY ANALYSIS ................................. 119
1  EXECUTIVE SUMMARY

1.1  PROJECT OBJECTIVE

The aim of the Latrobe Valley Microgrid (LVM) Feasibility Assessment was to assess the economic and other benefits of implementing peer to peer energy trading in the Latrobe Valley. The LVM will implement LO3 Energy’s blockchain based Local Energy Market (LEM) platform and smart metering devices to bind participants together in an Internet of Things (IoT) virtual microgrid. The platform utilises an eBay style auction mechanism to allocate locally produced renewable energy to those participants that value it the most, as expressed through their willingness to pay.

This feasibility analysis provides a preliminary assessment of the potential economic benefits of peer to peer energy trading in a LEM. In later phases of the project, as the capability and functionality of the platform will be further developed, the project will test the ability of the LEM platform to provide additional services to wholesale and ancillary services markets and distribution businesses.

The objectives of this feasibility analysis were to assess:

- Community perceptions of the value of peer to peer energy trading in the Latrobe Valley;
- The potential economic value of the LEM for both consumers and prosumers; and
- The regulatory barriers to implementing a LEM and possible ways of addressing them.

1.2  RECRUITMENT OF FEASIBILITY PARTICIPANTS

The first step was to test the Latrobe Valley’s appetite for a local, community-focused energy marketplace. This was kicked off with two ‘Let’s Build a Microgrid’ workshops held in Morwell in mid-2018. The workshops were interactive and attended by approximately 30 people from the Latrobe Valley community. The objectives of the workshops were to gather views on the following:

- How the local community views the energy status quo.
- What they envision for the Latrobe Valley’s energy future.
- Whether the concept of a community marketplace or virtual microgrid, where renewable energy was bought, sold and shared locally was interesting to them.

During the workshops participants expressed a strong interest in renewable energy, particularly if it could save them money on their energy bills, and strong support for innovative and sustainable projects that would improve the community welfare and move the Latrobe Valley away from its historical economic dependence on coal-fired generation capacity.

Eighty-one participants were recruited to take part in the feasibility study. These participants comprised 37 residential customers, 23 farms and 21 commercial customers. The initial requirement for participants was to make their historical energy consumption data available to the project partners for the purposes of the feasibility study. This energy consumption data consisted of one full
calendar year of meter data obtained from AusNet Services and data obtained from customer electricity bills (retail tariff and its structure and components).

The recruitment of participants and the issues LO3 Energy encountered in the recruitment process are covered in detail in Section 4.4 of the report.

1.3 COMMERCIAL FEASIBILITY ANALYSIS

The key focus of the feasibility analysis was to assess the potential for peer to peer trading to potentially lower energy purchase costs for consumers and increase returns for prosumers. It should be noted that the modelling focused entirely on economic outcomes, i.e. potential financial gains to both consumers and prosumers. The economic modelling did not consider other less tangible value to participants from purchasing on the LEM, for example, keeping more of their energy spend within the local community, supporting development of new skills, taking action on climate change etc. A key outcome of the workshops and customer survey was that these issues were important to the community, however we did not explicitly estimate a financial value for these benefits (i.e. we did not investigate whether customers would be willing to pay more for their electricity if it came from the local community).

The commercial feasibility analysis asked two principal questions:

- What were the potential economic savings for consumers from buying electricity from a local energy marketplace versus what they currently pay under their retail tariff; and
- What were the potential economic gains to prosumers from selling electricity on a local energy marketplace versus selling their excess solar generation to the retailer

These questions were tested under three separate scenarios. The scenarios differed on the basis of how network costs and market costs were allocated between buyers and sellers on the LEM.

Each scenario compared the economic gains made by buying or selling on the LEM against a counterfactual. For buyers the counterfactual represented what they would have paid for the volumes transacted on the LEM at the retail price. For prosumers or sellers the counterfactual represented what they would have received for energy sold on the LEM at their Feed in Tariff (FiT).

It was also assumed a retailer was required to manage the LEM in each scenario, due to the requirement for a Financially Responsible Market Participant (FRMP) at each connection point under the existing framework. A hypothetical retailer was modelled in the analysis (based on aggregated

1 The retail price reflects the next best alternative for consumers and the FiT represents the next best alternative for those customers with solar PV, so these represent the appropriate reference points for determining the economic value of peer to peer trading.

2 Market costs are defined in this feasibility analysis as the combined costs of running the wholesale market and costs of environmental schemes, such as the Renewable Energy Target, Energy Efficiency schemes and administering the Feed in Tariff. These costs are recovered from retailers on the basis of their market share and retailers pass these through as a volumetric c/kWh charge to their customers.
retail data collected) to establish the potential financial impacts of a LEM on the LEM responsible retailer.

With these considerations in mind the three scenarios modelled were as follows:

- **Scenario 1**: Buyers and sellers on the LEM transact on the basis of the auction price only – LEM buyers are not required to pay network and market charges for the volumes they transact on the LEM. This places them in the same position as solar customers, who also do not pay network and market charges for the energy they ‘self-consume.’ Scenario 1 sought to extend the benefits of renewable self-consumption to customers who may not have the option of installing solar themselves (e.g. renters). However, network and market charges will still need to be recovered and are assumed to be borne by the retailer in this scenario.

- **Scenario 2**: Customers who purchase from the LEM are charged a network and market component for their LEM consumption and prosumers pay a network and market component for their sales on the LEM. Under this scenario exports and imports to the network are treated equally. Both parties pay to use the network for energy transacted on the LEM.

- **Scenario 3**: This scenario reflects current arrangements. Consumers are assumed to pay the usual volumetric network and market charges for the electricity they transact on the LEM. Therefore, regardless of whether a customer purchases energy from the LEM or from the retailer, the same network charges apply.

The scenarios are discussed in detail in Section 5.1.1 of the report.

As auction outcomes of the LEM cannot be known ex ante, these outcomes were estimated by using collected retail tariff data to construct three hypothetical demand curves for each scenario, representing a high, medium and low willingness to pay. These were then used to determine a high, medium and low auction price outcome for each scenario, with the auction pricing outcome then compared to the counterfactual for consumers and prosumers.

### 1.4 RESULTS

The outcomes of the feasibility modelling suggest that consumers and especially prosumers can potentially benefit from participating in the LEM in each of the scenarios examined (that is, regardless of how market and network costs are allocated). The results are covered in detail in Section 5.3 of the report.

#### 1.4.1 SCENARIO 1

Unsurprisingly, both consumers and prosumers make the most gains in Scenario 1. Consumers collectively could potentially make savings of between 31% and 41%. Prosumers could achieve

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3 The range is determined by modelling a high, medium, and low willingness to pay for buying their energy locally compared to the same volume of energy purchased from the grid.
additional revenues on their solar exports of between 53% and 107%, compared to their current Feed in Tariff (FiT).

However, the hypothetical retailer modelled in the analysis made a potential financial loss of 10% on the volumes transacted on the LEM (this comprises lost margin of 13% on lost volumetric sales and unfunded network and market costs).4 As a consequence, for Scenario 1 to work as a business model under the umbrella of a retailer, the retailer would need to be able to recoup the losses on unfunded network and market costs in other ways. For example, on the retail tariff applied to the residual grid purchases from those customers, or through bundling a peer to peer product with other energy products and services (e.g. energy management, solar, batteries etc).

1.4.2 SCENARIO 2

In Scenario 2, both consumers and prosumers pay volumetric network and market costs for energy transacted in the LEM. This scenario would require prosumers to give up some of the benefits they currently achieve from self-consumption. It reflects a view that prosumers also benefit from using the network to export their electricity and should therefore contribute to the costs of transport.

Consequently, because consumers and prosumers fund network and market costs in this scenario the hypothetical retailer makes a potentially much lower financial loss of 1.8% on LEM volumes (reflecting lost margin). Consumers still potentially make significant savings of between 11.4% and 22.9% compared to normal energy purchases, however prosumers potentially make significant losses of between 7.5% and 29% selling their exports on the LEM rather than to their retailer at the FiT. This is because for every unit they export on the network, under this scenario they would also now pay network charges, where they currently do not. From a prosumer perspective, participating in Scenario 2 is therefore only worthwhile in a situation where the rules were changed so that all prosumers (not just those who participate in LEMs) were obligated to pay a volumetric export charge, otherwise there would be no incentive for them to participate in the LEM.

While a network export charge applied to prosumers may be justified on an economic basis, this would be a controversial change to the rules. It could also undermine LEMs by creating strong incentives for prosumers to limit the size of their solar installations and install batteries for the express purpose of maximising self-consumption.

An alternative approach to applying an export charge is to encourage network businesses to implement non-discriminatory cost-reflective tariffs for solar customers (which is discussed in more detail in Section 6.2.3. In particular, a peak demand charge ideally based on coincident peak demand would ensure a more equitable sharing of the network costs between consumers and prosumers, since such a charge would no longer be volumetrically based. Customers would have stronger incentives to maximise the export capability of the solar they install while reducing the incentive of existing solar customers to focus on maximising self-consumption (for example through installation of batteries). Such a charge could also operate as a negative demand charge or peak rebate for

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4 13% was an average of all retailers in Victoria calculated by the Grattan Institute. See Grattan Institute “Price Shock: Is the Retail Electricity Market Failing Consumers”, Mar 2017, p 13
prosumers with batteries to encourage them export their energy at those times it is most valuable to LEM customers and the network.

1.4.3 SCENARIO 3

In Scenario 3 the modelling results show the lowest potential economic value for consumers participating in the LEM, but is the scenario immediately implementable under current regulation. This is because they bear all the market and network costs in this scenario (reflecting current rules). Despite this however, there were still material savings for consumers and even more significant gains for prosumers. Consumers potentially save between 6% and 12% on their energy purchases while prosumers potentially gained between 18% and 37%. Prosumers benefit from obtaining higher compensation for their exports than they do under the current FiT (this follows from the Fit acting as a floor price).

The results are covered in detail in Section 5.3 of the report.

1.5 REGULATORY FEASIBILITY ANALYSIS

A core objective of the feasibility assessment was to investigate the current regulatory framework in which a LEM would operate and the potential regulatory barriers to services the LEM could deliver for its users in the future (e.g. access to wholesale markets). The long term vision for the LEM is to provide a market platform for transacting a range of new energy services, including peer to peer energy trading, demand response and virtual power plants, in a way that will allow the LEM to operate as a true market, not one necessarily controlled by a single retail intermediary. A number of other barriers exist to implementing a LEM. The regulatory barriers are considered in detail in Section 6.2 of the report.

The project partners commissioned King and Wood Mallesons (KWM) to assist in identifying the current regulatory barriers and any potential solutions for resolving them. The detailed report developed by KWM is included in Appendix I.

Based on the KWM report, LO3 Energy considers the following areas worthwhile for further work and consideration to support the development of LEM platforms and other innovative business models. Some of these recommendations would require a proof of concept trial, supported by a regulatory sandbox. The LVM project provides a good opportunity for this type of arrangement to be implemented.

The recommendations of this report are listed below and covered in detail in Section 7.

1.5.1 RECOMMENDATIONS

1. Investigate the benefits and costs of establishing a new Market Participant classification or classifications for ‘New Energy Service Providers’, covering services such as demand management, aggregations of DERs (also known as Virtual Power Plants or VPPs) and peer-to-peer energy trading.

2. Investigate the benefits and costs of allowing consumers to contract with multiple service providers at the same connection point.
3. Endorse the Australian Energy Market Commission’s (AEMC’s) continued work on developing a demand response mechanism to allow for demand response to be bid into the wholesale electricity market.

4. Endorse the continued work of the Australian Energy Market Operator (AEMO) to investigate the benefits and costs of allowing the increased engagement and access of DERs to wholesale and ancillary services markets.

5. Continue work on the development of a Distribution System Operator (DSO) model and evaluate the potential for distribution level markets that will allow trading of new energy services, such as demand response, aggregated generation and peer-to-peer energy trading, at the distribution level.

6. Facilitate data sharing between Market Participants, while maintaining privacy and confidentiality protections.

The proposed Latrobe Valley Microgrid (LVM) project will demonstrate how local distributed energy resources (DERs) can be incorporated into a Local Energy Market (LEM) to improve economic and social outcomes for participants and support a more efficient grid.

The objective of this feasibility assessment was to estimate the potential social and economic value of the LEM to the Latrobe Valley community. The study involved 81 participants who agreed to make their personal data available to the project partners for the purposes of the feasibility study. Some of these had multiple National Metering Identifiers (NMIs). Some had incomplete data which meant they were excluded from the final data set. This meant we ended up with a total of 94 NMIs being involved in the study, comprising 36 residential, 54 farms and 4 commercial connection points. This data set was defined as the LVM94. The modelling approach is discussed in Section 5.2, key outcomes of the modelling are discussed in Section 5.3 of the report.

Another core objective of the feasibility analysis was to investigate the current regulatory framework in which a LEM would operate and highlight potential regulatory barriers to LEM value streams. The barriers and potential solutions to address them are discussed in Section 6, with a detailed report included in Appendix I.

3 BACKGROUND

3.1 THE LATROBE VALLEY

Situated east of Melbourne, Australia, the Latrobe Valley consists of three major population hubs Moe to the west, Morwell situated centrally, and Traralgon to the east. The Latrobe Valley’s population is approximately 75,000 people, the population in the wider Gippsland region exceeds 250,000 people.\(^5\)

The Latrobe Valley is unique in that it is a key economic region with its history deeply embedded in brown coal fired energy generation since the 1920s. The area produces in excess of 90% of the electricity for the whole of Victoria\(^6\), and exports to NSW and Tasmania. The power generation industry is the second highest employer in the Latrobe Valley at 4.2% of the population (compared with 0.1% in the rest of Victoria and Australia). This is followed by retail and the logging industry. The healthcare industry is the highest employer at 5%. The agri-business sector makes up approximately 37% of Gippsland’s businesses, 50% of which is in livestock production, including dairy farming.\(^7\)

Reliant on the energy industry for employment and its livelihood, the Latrobe Valley is undergoing rapid changes with the nationwide push towards renewable energy resources. Most significant is the

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closure of aging fossil fuel generators, with Hazelwood Power Station closing in March 2017, and others expected to follow within the next two decades.

Recent studies demonstrate entrenched social disadvantage in a number of communities in the Latrobe Valley reflected in higher unemployment (particularly youth unemployment) and a lower labour force participation rate in Latrobe City, with pockets of very high unemployment and disadvantage in Morwell and Moe.8

Victorian retail energy prices are among the highest in Australia, which has even greater impacts for businesses operating in economically depressed areas such as Latrobe Valley. For example, the CommBank Agri Insights Report 20189 found that 83% of Victorian farmers feel they have no control over their energy costs and 67% stated that rising energy costs had a significant or moderate impact on their farming operations.

In recruiting participants for the LVM project it became clear that the impact of rising energy prices on local businesses, in particular dairy farmers who are also having to manage the unpredictable financial impacts of climate change on their businesses, is driving an increased interest in, and uptake of, new energy solutions to reduce energy costs, such as onsite solar PV and battery storage.

LO3 Energy also found a strong drive within the local community to work collectively to maintain the Latrobe Valley’s reputation as a key electricity producing centre of Victoria as it transitions away from thermal power production to a cleaner energy future.

3.2 ENERGY MARKET CONTEXT

The Victorian electricity system is one of the five market regions within the National Electricity Market (NEM). The NEM is the wholesale electricity market for the electrically connected states and territories of eastern and southern Australia – Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania. Western Australia and the Northern Territory are not connected to the NEM. They have their own electricity systems and separate regulatory arrangements.10

The NEM facilitates the exchange of electricity between generators and retailers. The Australian Energy Market Operator (AEMO) operates the NEM. The NEM is an energy-only gross pool with mandatory participation for retailers and generators with a capacity of 5 MW or above.11 That is, generators are required to sell all of their electricity through the wholesale spot market, while retailers are required to purchase all of their electricity from the spot market. Some large consumers can also purchase electricity directly from the market. High voltage transmission lines transport

11 See National Electricity Rules (NER) provisions for Market Generator (NER 2.2.4) and Market Customer (NER 2.3.4). The NER are accessible at www.AEMC.gov.au; for generator size thresholds see NER 2.2.1(c) and NEM “Guide to Generator Exemptions and Classification of Generation units, accessible at www.aemo.com.au
electricity from generators to electricity distributors, who deliver it to homes and businesses on lower voltage ‘poles and wires.’

Perhaps the three most significant challenges facing the NEM are rising energy prices, decarbonisation and decentralisation. These challenges are having a profound impact on consumers and the power system.

Rising Prices

A recent inquiry by Australia’s competition regulator, the Australian Consumer and Competition Commission (ACCC) into retail prices found that electricity prices had increased by 30 percent between 2007 and 2018 and retail profit margins per customer have more than doubled from 5% to 10% on average over that time. They identify a number of reasons for this, including a lack of competition in wholesale and retail markets and a decade of overinvestment in both transmission and distribution networks.\(^\text{12}\) Additionally, in its 2018 annual review of retail competition the Australian Energy Market Commission (AEMC), found that only 25 per cent of residential customers believe the energy market is working in their long-term interest and only 44 per cent think they are getting value for money.\(^\text{13}\)

Decarbonisation

The power system is in the process of radically transitioning from fossil fuelled power to renewable energy. While currently only making up about 12% of overall capacity in the NEM (though near 40% in South Australia) there is currently 41 Gigawatts that has been granted or is waiting for Development Approval (DA).\(^\text{14}\) However, integrating such a large volume of variable renewable power generation will present significant challenges for the grid. Large volumes of intermittent generation capacity make it much harder to balance the grid, as both solar and wind generation can fluctuate rapidly depending on weather conditions. This increases the risk of disruptions to the power system and increases the cost of procuring ancillary services to avoid such disruption.\(^\text{15}\)

Decentralisation

Australia is leading the world in the installation of rooftop solar PV. Already two million Australian households have solar panels. Bloomberg New Energy Finance estimates Australia will be the most decentralised energy market in the world by 2040, with 45 per cent of all generation capacity located behind the meter.\(^\text{16}\) This is creating technical challenges for network businesses as they now have to manage the impacts of massive increases in two way flows on local grids, which were originally designed to accommodate flows only one way.

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\(^\text{12}\) ACCC, Retail Electricity Pricing Inquiry, Final Report, 2018, p iv. Page ix particularly notes there was significant over-investment in state-owned networks in NSW, Queensland and Tasmania.

\(^\text{13}\) AEMC, Retail Energy Competition Review, Final Report, 2018, p vii


\(^\text{15}\) AEMC, Frequency Control Frameworks, Final Report, 26 July 2018, p 28-2

Local Energy Market (LEM) platforms can play an important role in helping to address the market challenges identified above by contributing to more competitive retail markets and providing a platform for delivery of both wholesale and grid related services.

4.1.1 MORE COMPETITIVE RETAIL MARKETS

LO3 Energy’s LEM platform creates a new way for consumers and prosumers (people who consume and produce) to buy and sell electricity and manage consumption. It replaces, in part, the traditional electricity retail model with a blockchain based software platform and configurable auction algorithm which allows members to buy and sell energy to each other peer-to-peer and to provide the many services their DERs are capable of providing directly to AEMO, network businesses and retailers. The LEM platform will allow consumers to have greater influence over the price they pay for electricity and give them more choice, control and transparency over where their electricity comes from and how they use electricity.

While members of the LEM platform would pay a fee for accessing its services, prices would otherwise be determined through the interactions of buyers and sellers on the platform. Consumers will only pay as much as they value the energy they procure peer-to-peer on the LEM. Prosumers will receive the best possible price for the particular service their DER provides by means of the platform (e.g. local consumption, grid services or participation in a virtual power plant), since the service will be sold in a bid auction which will be won by the party that values that service the most and is willing to pay the most for it.

4.1.2 MORE COMPETITIVE WHOLESALE MARKETS

The LEM could provide a platform for allowing DERs to participate in wholesale and ancillary services markets. LO3 Energy is building capability into the LEM platform that will allow it to provide a blockchain foundation for recording, tracking, verifying and compensating the actions of virtual power plants (DERs that are ‘virtually’ grouped on the network to provide a combined output) and demand response (the reduction or increase of consumption or production based on market triggers) in the wholesale market.

The current focus is on providing for integration with other aggregator platforms to provide such services, as LO3 Energy does not expect to become an aggregator itself. LEM members are expected over time to provide an important source of competition in the wholesale market. The AEMC is currently consulting on new rules that will implement a formal wholesale demand response mechanism in the NEM, which will provide an important opportunity for the LEM platform to secure new revenue streams for its members.  

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17 For more information see https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism
A future focus for development of the LEM platform is to build functionality allowing buyers of DER services, such as retailers, AEMO and distribution businesses, to advertise contracts on the platform targeting DERs with specific characteristics (capacity, controllability, location) so their resources can be aggregated for dispatch or demand response into wholesale energy and ancillary services markets. The LEM would provide near real-time information on the location and capability of DERs to the distribution business or AEMO to ensure better integration of virtual power plants with existing network limits. In response to the advertised contracts, prosumers could flexibly self-organise into coalitions through a bottom up process based on individual prosumer characteristics. It is envisaged this process will be highly automated, based on a prosumer’s energy management system and preference settings, which are set using a mobile app.

In this regard the LEM platform has some important benefits over existing approaches to developing and recruiting customers for VPPs, which typically take a ‘top down’ approach to customer recruitment. Currently aggregators do not consider how a VPP based on many thousands of customers spread across a large geographic area might impact local network limits. Critical information on size, network location and local hosting capacity is often not available. Nor are participants recruited with consideration of the potential trade-off’s customers face with respect to the different markets in which DER providers may wish to participate and derive additional value. In contrast, the LEM implements a bottom up approach to aggregating DER resources, while giving customers transparency around the choices and trade-offs they face with different potential revenue streams. The key underlying premise of the LEM platform is that each prosumer would be able to compare and then choose the market transaction or contract that delivers it the most value.

Finally, the collection, storage and management of data will be an ancillary feature of the LEM platform, associated with an open-source data permissioning platform called ‘Exergy’. This functionality will be accessible to all LEM platform users as a means to permission access to- and potentially monetise- their data. As the number of users grows, a ‘data lake’ will be developed that comprises information on customer consumption, preferences and consumption profile, the size and nature of on-site DER (e.g. battery, solar PV, etc.) and the network location of LEM participants. This information will be accessible to retailers, aggregators, or AEMO via a marketplace only with the consent of the consumers who own the data. A blockchain data access framework comprising private and public access keys will keep data secure, establish an audit trail of permissioned access and provide a streamlined means for consumers to make data available to third parties.

4.1.3 A MORE EFFICIENT GRID

LO3 Energy’s long-term vision for the LEM platform is for it to be used for managing the impacts of high renewable energy penetration on the electricity grid. The platform would give AEMO visibility over the operational capability of the DERs in the network and provide access to other important market and network related information necessary for managing the grid.

While currently DERs cannot participate in ancillary services markets, the market rules are being changed to allow DERs to provide services into ancillary markets through aggregation (i.e. virtual power plants or demand response).\(^\text{18}\) The LEM platform could provide a channel for connecting DERs

\(^{18}\) This is discussed in detail in Section 7.3
to these markets and AEMO could establish contracts with specific LEM participants to elicit responses for ancillary services.

For example, AEMO could establish contracts with LEM participants with residential batteries and activate them (most likely through an aggregator) to dispatch electricity during a rapid fall off in solar or wind generation arising from a change in environmental conditions, helping to restore system frequency. Conversely, the batteries could be activated to absorb energy during the middle of the day if there is overproduction due to excessive solar generation in a specific part of the grid. By giving LEM users the ability to determine the price parameters of their participation, the LEM platform harnesses market forces to determine cost-effective means of physical outcomes on the grid.

This approach will also apply for network businesses with respect to managing the local network in a highly decentralised environment. The availability of detailed information on LEM participants would allow network businesses to advertise contracts for demand response or to utilise price signals on the platform (for example by passing through dynamic network tariffs) to incentivise LEM members to help with grid management.

For example, in congested or challenged parts of the grid, LEM members that have the right type of DER capability could be incentivised to provide solutions to address the congestion issue. This could reduce or eliminate the need for future capital investments in that area.

In summary, the key premise and focus for ongoing development of the LEM is to provide consumers, prosumers and producers with a market platform that offers a range of different services – such as grid services or the transaction of local energy - and allows them to choose the service that delivers them the most value at a particular point in time, based on the best prices offered by competing buyers.

This specific LVM project provides a valuable opportunity for LO3 Energy to build and evaluate new functions, capabilities and business models in collaboration with its partners and with access to a ready pool of motivated customers.

4.1.4 LOCATIONAL MARGINAL PRICING

LO3 Energy’s ultimate vision is for the LEM to develop into a fully transactive marketplace where real time price signals flow through to consumers varying by time and location and reflecting losses and constraints from the transmission system down to the local level. Such highly granular pricing would identify where and when DER providers could deliver the most value to the power system.

In its purest form this type of pricing, often referred to as locational marginal pricing (LMP), would reflect the marginal value of producing energy and the cost of transportation at each customer connection point in the distribution system.\(^\text{19}\) LMP uses power flow modeling and complex mathematical techniques to calculate the market price for electricity at each connection point on

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\(^\text{19}\) For example, in locations or at times when network capacity is scarce high prices would signal the value of turning off appliances or dispatching batteries to balance supply in a constrained area.
the transmission system.\textsuperscript{20} It has been employed for over a decade now at the transmission level in many North American markets and in New Zealand.\textsuperscript{21}

LMP has not to date been employed at the distribution level anywhere in the world. One reason for this is that it is only now that customers have access to the digital technologies necessary for allowing them to respond to such price signals, without requiring constant manual intervention. Today IOT-connected appliances, devices and home management systems can do that automatically for them.\textsuperscript{22}

However, while customers increasingly have the technologies available to them to respond to much sharper and more granular price signals, implementing them at the distribution level will be a highly complex endeavour. Pricing potentially many millions of distribution connection points will be significantly more complex than applying such prices to connection points only numbering in the thousands at the transmission level. LMP applied to the distribution level will likely entail significant costs to the IT systems of market operators, distribution business and retailers. It is not clear whether these parties and indeed consumers will be willing to bear these costs or the complexity of distribution level LMP. Further, exposing customers to potentially highly volatile prices at their connection points will create financial risks for consumers that they will need to manage, - customers awareness and understanding of the impacts of distribution LMP would therefore need to be carefully managed.

As a consequence, it is anticipated that distribution level LMP will not be implemented in any market around the world for some time. In the meantime, the LEM platform could serve as a bridge to the transactive energy vision through implementing a platform that allows DER services to be recognised and compensated and using price to allocate those services to those who value such services the most; i.e. the distribution business as a network service, the system operator as an ancillary service, to an aggregator for dispatch into the wholesale markets or to a neighbour as a peer-to-peer transaction.\textsuperscript{23}

4.2 TRANSACTIVEGRID LOCAL ENERGY MARKETPLACE PLATFORM

The LO3 Energy TransActiveGrid platform brings together various components to deliver a local energy marketplace where consumers can bid to purchase energy from their community. The basic platform is built on blockchain technology and smart contracts and requires a proprietary TransActiveGrid element (TAG-e) Compute Unit to be connected to each participant’s power meter. The user interface is a branded mobile app for market participants or a browser-based portal for market administrators. An alternative rollout plan may include integration with a third-party data provider, whether that is a participating utility or a mutually agreed-upon meter data aggregation.

\textsuperscript{20} MIT, Utility of the future, “an MIT Energy initiative response to an industry in transition”, 2016, p 102
\textsuperscript{21} Ibid, p 91
\textsuperscript{22} Ibid p 92
service. In such a deployment, the TAGE device would be omitted in favour of a customer’s existing Advanced Metering Infrastructure (AMI) or other data collection infrastructure.

The basic architecture is illustrated in Figure 1 below.

**Figure 1: TransActiveGrid Data Flow Diagram**

The TransActiveGrid® platform has three main groupings of components:

1. The Local Energy Marketplace and associated backend services
2. The Data Collection system, including the TAGE or data provider integrations
3. The Member Interfaces

The Local Energy Marketplace combines usage or generation data across the network, gathered from either the TAGE devices of participants or from third-party data providers. It uses that usage or generation data in combination with the participants’ bidding and budgetary preferences to create orders in the marketplace. The transaction processor then proceeds to fulfil those orders given the available supply and demand utilising the marketplace algorithm before recording the results into the marketplace history. This history is then made available as a reporting feature to member interfaces. For more information on this topic, refer to Section 4.2.2.

A TAGE device collects its market participant’s energy measurements and securely communicates them to the marketplace for energy trading and to the cloud infrastructure to display as meter history in the member interfaces. In addition, all TAGE devices in the network connect to the LO3 Energy Monitoring and Management Service which allows for status checks and embedded software upgrades. For more information, refer to Section 4.2.4.

The Member Interfaces consist of two types: marketplace participant apps and administrative web portals. The marketplace participant apps provide methods for participants to set their market
bidding preferences and to view both their meter and marketplace transaction history. The market explorer administrative portal provides a view into the community marketplace as a whole, allowing market administrators to confirm TAGe devices are properly functioning as well as viewing transactional data. For more information, refer to Section 4.2.9.

4.2.1 CLOUD ARCHITECTURE

The LEM is supported by a cloud infrastructure that provides API interfaces and backend data services for the mobile applications and administrative interfaces that enable members to interact with the system. The TAGe devices are all connected via internet, allowing them to share their data via cloud services and APIs to enable their remote management and maintenance. This is shown diagrammatically in Figure 2 below.

Figure 2: TransActiveGrid Cloud Infrastructure

The TransActiveGrid platform consists in part of cloud services to support both the mobile and web interfaces to the platform. These services are structured into 3 groups:

1. Horizontal global services
   a. Monitoring and Metrics

2. Regional Privacy Zone services
   a. Identity Service
   b. Union
   c. Meter Data Service
   d. Monitoring and Metrics

3. Deployment-specific services
   a. Marketplace and Marketplace Components

This structure allows deployment of shared resources while ensuring all local privacy and data protection laws and regulations are followed.

The cloud services are used to provide the following functions in the TransActiveGrid platform:
- TAGe device monitoring
- TAGe management
- Meter data collection and aggregation
- Member authentication and authorisation
- Marketplace data collection and aggregation
- Marketplace interface and redundant nodes

Data generated from TAGe devices or integrated from a project-specific third-party data integration is processed in Privacy Zone data centres. Privacy Zones are logical boundaries in which data is allowed to be processed and stored. These zones are enforced by running privacy-regional cloud services, geo-location based DNS routing for Internet-facing services, and strict access controls to the cloud platform.

Data uploaded from devices is encrypted-at-rest in cloud storage and transmitted between cloud services encrypted-in-transit via TLS 1.2. Marketplace data in the cloud is encrypted at rest using a unique encryption key for the marketplace.

Administrative access is limited to a set of identified LO3 full-time employees designated for the role.

A private blockchain for marketplace transactions is run entirely within the cloud. Each marketplace runs its own blockchain. Access to the blockchain by services is protected by keys issued initially during genesis, or by member keys created for the marketplace in member registration. Transactions occur within the cloud service tier. Blockchain services are not directly network accessible to the internet.

4.2.2 LOCAL ENERGY MARKETPLACE

The TransActiveGrid platform initiates transactions in the LEM by providing data collected at the grid edge from market participants via the TAGe devices or the third-party data integration provider. The data collected depends on the rules of the market. In these initial peer-to-peer transactions, the marketplace works on a supply and demand framework where net production contributed by prosumers is considered supply and net consumption taken by consumers (or prosumers who have exceeded their personal supply) is considered demand. Buyers determine their preferences and reflect these in bid prices to win the supply to cover their demand. After executing the rules of the market, the marketplace then records the transactions on the blockchain and communicates the results of those transactions via the platform’s member interfaces.

The TransActiveGrid platform currently uses an eBay style auction mechanism to allow consumers and prosumers to trade their electricity on the local market. Consumers and prosumers buy and sell energy by placing bids and offers through their app. The algorithm then matches consumers ‘willingness to pay’, as reflected by their demand bids, against the supply of renewably generated electricity made available locally. The available supply is then allocated in order of the demand bids. The supply from prosumers, which is assumed fixed each time period (as prosumers cannot control
how much they export), is pooled and offered into the market at a minimum reservation price - e.g. the Feed In Tariff (FiT). Any consumption that cannot be met by the microgrid is supplied by the retailer through a customer’s normal fixed price retail contract.

The basic mechanics are illustrated in Figure 3 below.

**Figure 3: Local Energy Market Auction Mechanism**

![Graph showing the Local Energy Market Auction Mechanism]

While consumers will have access to real time information, they can pre-program their prices and preferences into the mobile app (e.g. a day, week or months in advance) so they can ‘set and forget.’

### 4.2.3 BILLING AND SETTLEMENT

The initial version of the TransActiveGrid platform tracks energy trades but does not process payments. The purchase/sale transaction logs contain the necessary information (price, volume, timestamp) to determine the debit or credit owed to a member over the course of the existing billing period with their retail provider. However, no built-in mechanism is currently provided for payments to occur on the platform whether by fiat currency or cryptocurrency. In order for members to make a payment or receive a payment, the transaction log will be provided to the retailer to process those payments. This transaction log can be viewed or exported via CSV file from the Administrative Portal, at a frequency to match billing cycles. In addition, a monthly summation of transactions conducted on the marketplace can be made available for the retail partner or other partners to download as appropriate.

### 4.2.4 TRANSACTIVEGRID ELEMENT

The TransActiveGrid platform includes hardware devices deployed at the grid edge. The hardware elements, called TransActive Grid elements (TAGe), are computers and communication gateways that (1) collect energy data and (2) communicate with the LEM Cloud Platform. These TAGe devices connect to the internet, allowing them to share their data with one another and with other platforms via LO3 Energy’s cloud services and APIs. At each layer of data communication, advanced
security protocols are included to ensure secure exchanges between the TAGe devices and external systems.

TAGe devices form the distributed data collection network of the LO3 Energy TransActiveGrid platform. Each TAGe collects measurements of energy usage from connected smart meters then securely communicates that to the LEM. The TAGe devices are permissioned to join the network and report consumption and generation on a participant’s behalf.

The TAGe device is a small single board computer (SBC) that can be configured to record multiple sets of interval data from a connected third-party electricity meter. The data sets available to the TAGe depend only on the capabilities of the third-party meter; examples include power, energy, voltage, current, line frequency, power factor, and more. The TAGe collects the desired readings and reports them back to the TransActiveGrid network. The TAGe devices may host nodes of the Local Energy Market blockchain depending on deployment requirements. They are self-contained units needing only power and network connection during normal operation.

4.2.5 SECURITY
The external casing of the TAGe device is enclosed in a plastic, sealed enclosure. Physical access to the hardware is only accessible with a screwdriver and adhesive and tamper resistant screws are used if the deployment requires it. The bottom of the case has ports for Ethernet, power, and RS-485 communications.

The TAGe devices run a hardened deployment of OpenEmbedded Linux (based on kernel version 4.16), where all unnecessary services have been removed and unused network ports have been disabled.

4.2.6 SUPPLEMENTARY DOCUMENTATION
Additional documentation on the TAGe device is available containing details on the specifics of the device and installation of the device on request.

4.2.7 SUPPORT FOR ONGOING OPERATION AND MAINTENANCE
The TAGe devices do not require regular services during normal operation. As part of any device deployment, LO3 Energy monitors and provides periodic software updates.

4.2.8 DATA PARTNER INTEGRATION
As part of ongoing project-based development, one of the options that LO3 Energy offers in support of partners is integration of third-party data platforms into the LEM. The amount of effort required to perform such an integration may depend on the following:

- Availability of data from the third-party data platform
- Authentication from the LO3 Energy LEM to the third-party data platform
- The format and delivery mechanism of the third-party data platform
• The ease of mapping the data sources onto participants of the LEM.

As the feature sets of third-party data platforms may vary, it should be mentioned that they may have a substantive impact on the specifics of the LEM deployment. Should data be only available on a significant delay from real-time, for example, the processing of marketplace transactions may be delayed accordingly. If the third-party data platform provides a lower resolution of data to the Local Energy Marketplace, subsequently the Local Energy Marketplace will not be able to process settlements on the same period as it would if there was a deployment of the TAGe to participants.

4.2.9 MEMBER INTERFACES

4.2.9.1 PARTICIPANT APPS

The TransActiveGrid platform includes a participant app specifically designed so that participants can interact with the LEM. The initial version of this app provides the participant with the following functionality:

• Opt to register with the marketplace to buy local energy and/or sell their excess energy
• See the current trend for local energy pricing (see Figure 4a)
• Choose their maximum bid price for buying local energy (see Figure 4b)
• Review statistics of their energy activity, bought and sold
• Review their consumption and production (see Figure 4c)

Figure 4: Participant Interface to the Local Energy Marketplace, a) Today’s Dashboard, b) Preferences to Buy Energy, c) Consumption History
The TransActiveGrid platform includes a web-based administrative interface specifically designed to enable market administrators to inspect the operation of the platform. The initial version of this provides the following functionality:

- For installed TAGe devices
  - View operating status (see Figure 5)
  - View meter readings (see Figure 6)
  - Export meter readings to CSV file
- For the operating LEM
  - View marketplace transactions (see Figure 5)
  - Export transactions to CSV file

The administrative interface features may vary for third-party data integrations.

Figure 5: Administrator interface to the TransActiveGrid platform - Device status
Figure 6: Administrator interface to the TransActiveGrid platform - Meter readings

Figure 7: Administrator interface to the TransActiveGrid platform - Marketplace transactions
4.3 LATROBE VALLEY MICROGRID DISTRIBUTION NETWORK

4.3.1 CURRENT CAPACITY AND SOLAR PENETRATION

AusNet Services has not identified localised demand constraint issues in the Latrobe Valley. However, there are two issues that need to be considered for the new solar installation sites proposed as part of this project:

- The size of the new installation may be limited due to the low level of local demand available to absorb any additional exports; and

- There may be greater sensitivity related to distribution transformer ratings, especially if large scale solar is proposed to be connected for export purposes.

Many sites identified for proposed solar installations are rural and the network has limited flexibility in terms of power quality because many of these locations have two-phase and Single Wire Earth Return (SWER) connections, which are weaker and typically not able to support larger utilisation.

Most of the participants that have been provided a solar storage proposal for the implementation phase are connected to smaller scale distribution transformers. The distribution transformers have been sized so that the installed capacity economically aligns with the connected customer loads. However, this sizing then governs the size of any embedded generation further downstream if network augmentation is to be avoided.

Under AusNet Services’ existing embedded generation connection policy, the total allowable system capacity within a local network is limited to the rating of the network’s supply distribution transformer, minus any existing embedded generation on that transformer. This represents a fail-safe position in terms of potential thermal derating of the asset and shortening of the asset lifecycle as it maintains a consistent risk profile for the network assets, as well as avoiding asset failure in extreme cases. Total allowable embedded generation export is limited to a percentage rating of the capacity of the supply assets based on a technical engineering review of the local network.

AusNet Services’ existing connection rules state that:

- Maximum installed capacity (solar + storage) for single phase is 10 kVA and 5kVA export

- Maximum installed capacity (solar + storage) for 2 phase is 20kVA with 10kVA export (maximum 5kVA export per phase)

- Maximum export capacity (solar + storage) for single phase SWER is 3.5 kVA and two phase SWER is 7 kVA

This is as per AS:NZ477.1:2016 which limits export at 5kVA export for single phase and stipulates that a multiphase system shall have a balanced output with respect to its rating with a tolerance of no greater than 5kVA unbalance between any phase.
For 3 phase sites, the export can be larger than 5kVA per phase, but AusNet Services limits the export to consider all supply assets based on a technical assessment. A technical assessment of the connection application reviews the phase balance protection where not integrated in the inverter, under/over voltage and frequency protection.

If the Latrobe Valley Microgrid proceeds to the implementation phase, all new solar and storage grid connection applications would undergo AusNet Services’ formal embedded generation connection application process, details of which can be found via AusNet Services’ website: https://www.ausnetservices.com.au/New-Connections/Solar-and-Battery-Connections

4.4 FEASIBILITY STUDY PARTICIPANTS

4.4.1 RECRUITMENT

The Latrobe Valley Microgrid (LVM) offers electricity consumers in the area an opportunity to participate in a Local Energy Market (LEM). Whilst the idea around sharing electricity that has been produced by local residential and commercial solar PV and batteries sounds straightforward enough, electricity users are encouraged to become more aware of how much they are using, how much they are paying, what they are receiving for excess solar production, where their electricity comes from and what is important to them when it comes to the transition towards cleaner energy future. This project encourages active participation in reducing consumer energy costs and supporting the local community.

Participant engagement was targeted within the four council boundaries of Latrobe City Council, South Gippsland Shire, Baw Baw Shire, and Wellington Shire. There was generally a very positive response to the concept. Several participants saw the concept and underlying technology as way of giving back to the Latrobe Valley some of their lost energy identity.

4.4.1.1 CONNECT

The first task was to gather the sentiments of the Latrobe Valley community around their current satisfaction as consumers of electricity, what they would like to see change, and why they wanted these changes. More significantly, whether there was desire for a LEM like the Latrobe Valley Microgrid (LVM) that would serve to support locally produced renewable energy and keep energy spend within the community.

A ‘Let’s Build a Microgrid’ workshop in Morwell was conducted and brought together 30 people from the Latrobe Valley community who were keen to support innovative and sustainable projects that would improve the community welfare. As an interactive workshop, the activities revolved around gathering participant opinion of the following:

- How they see the energy status quo
- What they envisage for the Latrobe Valley’s energy future
- How the LVM could fit into their vision for the future
This workshop posited a strong sense of a community-led drive towards renewable energy and away from a reliance on coal generation. Environmental factors were at the heart of this vision, along with the creation of local jobs and a reduction in energy prices.

4.4.1.2 ENGAGE

The LVM website and social media page on Facebook were sources of direct information and updates. These contained various short videos, as well as information sheets that outlined the project idea and scope in a more interactive format.

Informational and promotional blogs were pushed through our partners’ channels in the Latrobe Valley, as well as local papers and radio stations. Community ambassadors promoted the project, reaching out to their contacts in the area and sharing their enthusiasm for the project.

Speakers from LO3 Energy, Sustainable Australia Fund (SAF) and Dairy Australia attended relevant local events to speak about the LVM project.

A survey was generated to gauge the public’s enthusiasm for the project, with results shown in Section 4.7.

4.4.1.3 REGISTER

To take part in the feasibility study, participants were asked to either go online to register or have the consent form(s) posted out to them. There were three options available:

1. Provide data only – this involved signing a consent form to allow access to 12 months of their electricity consumption data (Form 1)

2. Provide data and have a solar PV installation quote (Form 2)

3. Provide data and get both a solar PV installation quote and a financing quote (Form 2)

All consent forms were collected and forwarded to AusNet Services who verified details for each registration. When all requirements were met, the data was released to LO3 Energy who then disseminated the data and registration details according to the participant’s requirements and the data sharing arrangements that were in place between partners to protect confidentiality and privacy.

For those who requested a solar PV installation quote, the details were forwarded to CommPower Industrial (CommPower). CommPower conducted an initial consultation to establish the needs and requirements of the participant and inform them of any grants or financing options. An evaluation then followed with a comprehensive energy audit of the participant site. CommPower prepared their recommendations, estimated savings and plan for implementation, provided as a desktop solar proposal. Details of those participants who requested solar proposals are discussed in Section 5.5.

Quotes from CommPower were shared with Sustainable Australia Fund (SAF) who then prepared Environmental Upgrade Agreement (EUA) funding assessments where that option had been selected, and where EUA funding was available.
MONTHLY UPDATE

Monthly updates on the progress of the project are sent out to feasibility participants via email. Updates are also posted to the social media channel to keep interested parties abreast of the project.

LESSONS LEARNED

During the recruitment process there were lessons learned that could help make recruitment during the implementation phase of the project smoother. Some of these lessons, as well as other lessons learned from other LO3 Energy pilot projects are described in more detail below:

1. **Accessing data is not straightforward.** The modelling in the feasibility study required access to participants energy data. On the plus side, smart meters are the norm in Victoria, which means that there is half-hourly data available at almost all connection points. Getting access to that data, however, is not straightforward. Participants needed to sign a legal declaration and fill in a fairly lengthy form allowing access to their data. After some potential participants expressed concerns about the barrier that put in place, digital signatures were deemed sufficient. The details on the form were then verified by AusNet Services and data batched and sent through. There was generally a lot of in-person enthusiasm for the project, but the flow through to signed forms was a trickle of the interest received. Part of that was the process itself being cumbersome.

2. **It was not as simple as tick-the-box.** As well as filling out and signing a form, participants needed to provide a copy of their retail bill for the breakdown of network and retail charges. Again, this was another barrier for completion, as there were a number of participants who filled in forms but failed to send through their retail bills, which meant they were excluded from the data set.

3. **Some participants, particularly farmers, have multiple National Metering Identifiers (NMIs).** This meant they had to list out details for each of their NMIs and provide the associated retail bills for each of those NMIs. There were instances of different retailers, or different retail plans, for NMIs under the same participant. NMIs without a retail bill were excluded from the data set.

4. **Retail plans are confusing.** Even when the bill for each NMI was received there was quite a wide variation in the type of information displayed on the bill, and how it was displayed. In most cases it was necessary to refer to retailer websites (applying details from the participant) to ensure a full data set was received. This task became one of the most time-consuming and laborious of the data set collation.

5. **Local community advocates are the key to success.** This lesson has also been learned in other LO3 Energy pilot projects, most notably the Brooklyn Microgrid. There’s a big difference between having an outsider ‘sell’ something versus having a trusted member of the community advocate on behalf of a project, or proposition. In Brooklyn, the vast majority of recruitment was through word of mouth, where a small number of enthusiastic community members talked to their neighbours and other community members and
introduced them to the project. Having local people, trusted within the community, makes a huge difference to how the project concept is viewed.

6. **People are concerned about power prices.** The overwhelming message received when talking with people in the Latrobe Valley was that they were excited about the project concept, and liked all the add-on benefits that could be derived (such as climate change action, keeping energy expenditure within the local community, creating new jobs, supporting innovation, supporting a transition in the Latrobe Valley to ‘new energy’ skills) but they did not want to pay more for local renewable energy. Local renewables had to be cheaper.

7. **People are concerned about how power prices will evolve.** Uncertainty is a big driver for many people in making the decision about whether or not to install their own solar system, and indeed whether or not to install a battery (even when it is not economically rational to do so).

8. **People are not always economically rational.** Everyone has their own set of personal drivers. For a lot of people this will mean saving money, but this is not the only driver. For some feasibility participants achieving greater independence from the grid or their retailer was more important than the economics of converting to onsite solar and/or batteries.

9. **Local ‘matters’ in every market, but drivers differ and the definition of ‘community’ can be more flexible than geographic.** As an example of this, in the Brooklyn Microgrid, local renewables are offered at a premium to grid electricity, not cheaper. This is in part due to the fact that net metering is in place in New York and elsewhere in the US, but also because ‘Brooklyn-made’ electrons are viewed as a premium product.

10. **People do not necessarily seek out the cheapest energy deal.** Price is not the only factor that comes into play. Other drivers include wanting to support renewables, wanting better customer service, wanting to support smaller or more innovative retailers or simply not having the time or willpower to research other options fully. As noted above, the number of different retailer plans and offerings is incredibly complex, and not easy to navigate.

11. **Energy bills should be more useful.** Even with the widespread roll-out of smart meters in Victoria there is very little meaningful information on bills that allows customers to take action in a targeted way to reduce their energy bills. For example, while the majority of the LVM participants were on Time of Use (TOU) tariffs, the peak window was typically very wide (7am to 11pm) and there was no disaggregated information on tariff components.

### 4.5 SOLAR PROPOSALS

Participants responsible for 31 NMIs opted to request a solar installation quote, resulting in a variety of installation proposals being submitted to AusNet Services for high level embedded generation connection application review. These were:

- 25 sites with solar and energy storage
- Three sites with solar only
• Three sites with energy storage only
• Three NMIs without any solar or energy storage
• Two different NMIs repeated with different solar and storage combinations

For the proposed installations, NMI connection types, system capacity and storage inverter ratings would be verified, and for larger connections Single Line Diagrams (SLDs) would be submitted during the formal application process.

Technical details of the proposed solar installations are included in Appendix A.

A high level technical financial analysis revealed payback periods on the solar proposals ranged between 7 and 12 years with financing from the SAF and assuming an FiT of 11.3 c/kWh. It was assumed for the purposes of the feasibility analysis that this payback range was sufficient to encourage installation of the 25 solar installations (noting that higher export revenues available under the LEM would reduce these payback periods, though this was not modelled). An assumed generation profile for each of 25 solar proposals was incorporated in the feasibility modelling.

A separate modelling run was completed assuming no change to the existing level of solar penetration (i.e. excluding the 25 proposals). The outcomes of this modelling run are included in Appendix F. While the data from these systems was used in the modelling, any proposed installations would need to submit a formal application for grid connection, as noted above.

4.6 ENVIRONMENTAL UPGRADE FINANCE

As well as offering participants an option to request desktop solar proposals, participants could also request a finance quote. Sustainable Australia Fund (SAF) assessed the cash-flow of each site that also requested a finance quote utilising Environmental Upgrade Agreements (EUAs), a form of fixed interest finance repaid quarterly through local council rates. Finance terms are available up to 20 years in term and can be novated to future owners of land or occupiers of the land. Utilising EUAs to finance these types of installations allows projects to become cash-flow positive as the repayments are repaid over long periods.

Of the 28 sites requesting either Solar or Solar and Battery quotes only 6 requested finance quotes. The 6 Sites that requested finance quotes were each sites with solar and battery proposals (i.e. none were solar only).

Each site assessment was designed for on-site electricity consumption, bar one, whose majority of electricity was exported. The greatest economic impact for businesses is to offset electricity costs from the grid. Electricity exports were valued at the state-wide FiT.

On a pure cash-flow basis (i.e. excluding any tax benefits), all except one site were not cash flow positive on finance terms of 15 years. However, on 20 year fixed interest finance terms all but one (the one exporting the majority of its electricity), became cash-flow positive from day 1.

With 20 year fixed interest finance repaid through council rates, the LVM would add value to the assessed sites where the prevailing price was above that of the FiT. However, without price certainty from the LVM we would assume none of the participants would specifically invest to earn
income from the LVM as a stand-alone business model, rather would potentially consider it where excess energy earned a greater value than that of the FiT, this is especially so when batteries are included in the cost equation.

One site (a dairy) was assessed where no battery would have been installed and all of its solar exported to the grid utilising 20 year finance term (note: the technical feasibility of this scenario was not assessed). This site would have been cash-flow positive from day one under such conditions. That is, even under an income of the FiT, a solar only site would earn more form the FiT, than it would cost in annual loan repayments. Where the LVM market price was higher than the FiT additional value may be created to solar only customers financing projects over 20 year terms. However, with no price certainty from the FiT or LVM, it is unlikely anyone would invest solely for export income where loan repayments are required to be made for a period of 20 years.

4.7 COMMUNITY SENTIMENT SURVEY

To assess whether there is consumer demand for something like a local energy marketplace, a survey of participant sentiment was undertaken to gather community views of the Latrobe Valley Microgrid and understand the motivations of people considering participating in the demonstration phase of the project.

There were 81 respondents and results to some of the key questions are shown below.

**Figure 8: First impressions of the project**

More than 60% of respondents ‘loved’ the project concept, with an additional 24.7% not understanding it. An education program, clearly outlining what participation would mean, would need to be part of the next phase of the project.

Survey participants were also asked about the social, environmental or financial benefits that were important to them. The results are shown in Figure 9 below.
A follow-up question asked which of the benefits listed in Figure 9 was most important to the respondent, and participants could choose one option only. There were two clear ‘winners’; saving money on your electricity bill was listed as the most important benefit by 37.0% of respondents and acting to address climate change was second with 23.5%.

Participants were also asked which of the benefits was least important to them and again there were two clear winners (or losers): supporting the local coal industry on 48.1%, and sticking it to the big electricity companies on 28.4%.

Participants were also asked to agree or disagree with the statements, as shown below:

- I think new technology is exciting
- I like to be the first to get the latest technology
- I want to be actively involved in where I get my energy from
- I want to be actively involved in how I use my energy
- I am happy with the service provided by my current retailer
- I trust my current electricity retailer
- I am prepared to pay a bit more for renewable energy from my local community
- I would be prepared to change how and when I use electricity if this could lower my bills
• I like the idea of buying renewable energy from my neighbours
• I like the idea of selling or sharing electricity that I produce with others in the community
• I believe what I am currently paying for electricity is fair
• I would buy electricity from my local community if it lowers my energy bill, even if only by a small amount
• I will only buy electricity from my local community if it lowers my energy bill significantly
• Addressing climate change is important to me
• I’m consciously trying to find ways to reduce my electricity bills
• I would prefer to see other people using new technology before I use it
• I want to support the renewable energy industry
• I want to support the local coal industry

The five highest scoring (i.e. more strongly agreed with statements) were, in order:

1. I think new technology is exciting
2. I like the idea of selling or sharing electricity that I produce with others in the community
3. I would buy electricity from my local community if it lowers my energy bill, even if only by a small amount
4. I want to support the renewable energy industry
5. I want to be actively involved in how I use my energy

The five lowest scoring (i.e. least agreed with statements) were, in order i.e. least agreed with first:

1. I want to support the local coal industry
2. I believe what I am currently paying for electricity is fair
3. I would prefer to see other people using new technology before I use it
4. I trust my current electricity retailer
5. I am prepared to pay a bit more for renewable energy from my local community

Respondents were asked about the concerns they may have about the project, and the results are shown in Figure 10.
Respondents were also asked if they were interested in participating in the Latrobe Valley Microgrid and gave the following responses: 45.7% responded yes; 46.9% maybe but I’d like to know more first; and 2% no.

In terms of DER assets already deployed, or potentially to be deployed: 58% of respondents already have solar installed, with a further 25.9% wanting to install solar; 3.7% already have batteries, with a further 48.1% wanting to install a battery; 2.5% already own an electric vehicle and 33.3% want one.

When asked “Would you like to have greater visibility and information about how and when you use electricity?” 74.1% responded yes.

There were also several questions asked to understand who the respondents were. There was a mix of residential, commercial and farm respondents. A summary of results is shown below:

- 72.8% of respondents lived within the Latrobe Valley, with a further 22.2% not in the Latrobe Valley, but within Victoria.
- 39.5% were aged between 41-60, a further 29.6% were aged over 60, and a further 27.2% were aged between 21 – 40.
- 30.9% of respondents had an annual income of between $50,000 and $80,000, a further 21.0% had an annual income of between $80,000 and $120,000.
The results are encouraging, showing there is consumer interest in the concept. Coupled with positive modelling results, showing there are economic benefits for buyers and sellers participating on the LEM, and other benefits such as climate change mitigation, keeping energy spend within the local community, developing new skills by implementing new technology etc it seems likely that there is a willing pool of potential participants, interested in an implementation phase of the project.

5 COMMERCIAL FEASIBILITY

The focus of the feasibility modelling was to provide a preliminary indication of the potential value available to consumers and prosumers by participating in an LEM - that is, the potential available savings for consumers from buying from the LEM and the potential additional revenues for prosumers from selling on the LEM against their Feed in Tariff.

It should be noted these are indicative only and highly dependent on the assumptions. Further, due to the uncertainties surrounding the cost of implementing and administering the LEM platform and associated hardware, these costs were not modelled. Such costs will vary significantly with the degree of scaling and the time period over which the fixed costs of implementing the platform are recovered.

A key focus of the LVM project during the implementation phase will be to assess these costs and examine different ways of allocating them (e.g. as a c/kWh transaction fee or subscription/access fee incorporated into the more general daily charge typically applied by a retailer to its customers). Ultimately, whether a viable commercial LEM product can be introduced will require these costs to be weighed against the benefits.

The costs of the 25 solar proposals were also not included in the feasibility analysis. These were assumed to be a sunk costs. That is, customers would install them regardless of the existence of a LEM. The LEM in this context simply provides an additional source of revenue over and above the FiT for these customers.

5.1 CONCEPTUAL FRAMEWORK

The current TransActiveGrid platform uses a sealed bid multi-unit (Vickery) second price auction mechanism for its Local Energy Market (LEM) platform. In this type of auction, the supply of a particular good is fixed and the highest bid for that good clears the auction, however the highest bidder only pays the second highest bid price. This approach ensures that bidders bid their true willingness to pay for the good. In circumstances where there are multiple units of a homogenous good, such as electricity, the Vickery auction allocates the available quantity (which for solar generation will vary considerably from one period to the next) in accordance with the bid prices until the market clears when the supply is fully allocated, although each bidder only pays the opportunity

cost (the bid of the next highest bidder) for the bid quantity they secure. The goods flow to those who value them the most - a fundamental principle of an economic efficiency.

The quantity of solar generation available for auction depends on the number and capacity of installations and environmental conditions at any particular point in time (e.g. no excess solar generation will be available after the sun goes down). Further, the auction is not for a fixed quantity but rather for whatever quantity is available given the variability of solar generation in any particular time period.

To capture as much as possible the Vickery auction format in the feasibility analysis required the development of a hypothetical demand curve for local energy. Hypothetical demand curves were developed based on the following assumptions:

- **Reservation price for consumers**: It was assumed a consumer’s reservation price or maximum Willingness To Pay (WTP) for local energy (i.e. their walk away price) was what they currently pay for energy under contract with their electricity retailer. That is, consumers will only be willing to purchase local energy if the price they pay for it is somewhere below their current cost of energy (and conversely they have a disincentive to purchase local electricity at a price higher than their current cost of buying energy).

- **Reservation price for prosumers**: It was assumed a prosumer’s reservation price or minimum Willingness To Supply (WTS) was the value of their next best alternative revenue stream - the Feed in Tariff (FiT). It was assumed that prosumers would be willing to sell their surplus energy on the LEM if the price they can achieve is somewhere above their current FiT.

- **Bid quantities**: Each consumer was assumed to bid their full current half-hourly demand for local energy. In other words, they wanted as much as possible if the price was right.

The reservation price for a consumer (equal to their avoided cost of energy) and reservation price for a prosumer (FiT) represent the upper and lower bounds respectively for each participating customer in the auction. In essence, this represents the range of feasible outcomes where both the seller and buyer will gain from trading with one another. However, an infinite number of potential outcomes are possible between these bounds, depending on customer preferences, budgets, and strategic behaviour. For example, some consumers will be more focused on saving money and will bid the minimum price they can get away with while still securing their desired amount of local renewable energy. Others may be more focused on achieving certain social and environmental outcomes and will make higher bids in line with their higher valuation of these outcomes. Others still, may bid strategically (i.e. below what they value local energy) in order to avoid being the marginal bidder and suffering the winners curse, since some participants who have bid lower will still secure their desired quantities in the auction.26

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The modelling attempted to capture these considerations by constructing three hypothetical demand curves that would lead to a low, medium and high auction price outcomes within the feasible range of reservation prices considered above (though in principle many other pricing outcomes are also possible depending on the preferences of consumers). The three demand curves were based on different WTP as follows:

- **Demand bid curve based on a ‘moderate’ WTP**: Each LVM consumer bids their demand at the mid-point between their own reservation price and the given price floor (FiT). This would arguably reflect the most efficient auction outcome, because both buyers and sellers equally share the available gains from the LEM.

- **Demand bid curve based on a ‘high’ WTP**: Each buyer bids their demand for local energy closer to their reservation price. To reflect this, bids in the model were increased by a 1/3 above the mid-point bid. Under this approach the buyer secures 1/3 of the economic value of LEM trading and the seller secures 2/3 of the value. This type of outcome could arise if LVM customers strongly support purchase of local energy for environmental or social reasons, and value it more highly as a group than alternatives. An alternative interpretation could be that consumers perceive availability of local supply to be low and believe they need to bid close to their reservation price to avoid the risk of missing out on their desired consumption level. This leads to a higher auction-clearing price, because the price above which bids are accepted by the seller will be higher given a limited available supply.

- **Demand bid curve expressing a ‘low’ WTP**: Each consumer places a demand bid closer to the prosumer’s reservation price (i.e. the FiT). Demand bids are 1/3 lower than the mid-point. With this auction outcome the buyer secures 2/3 of the economic value and the seller 1/3. This pricing outcome might apply in a LEM where buyers are primarily motivated by saving money, rather than environmental or social considerations. Alternatively, buyers may perceive local supply to be plentiful and consider a lower demand bid close to the prosumer’s reservation price will be sufficient to obtain their desired quantity and ensures they do not overpay for local energy. This leads to a lower auction clearing price, because the price above which bids are accepted by the seller given a limited available supply will be lower compared to the above two willingness to pay curves.

This is shown graphically in Figure 11 on the next page:
Figure 11: Representation of LEM Auction outcomes

Figure 11 shows that each WTP curve (low, moderate, and high) will lead to different gains and losses for participants under the modelling. The economic gain of the LEM for buyers is assessed by working out the area under the price ceiling and above the low WTP curve. The economic gain for sellers is the area under the Low WTP curve and above the FiT (the seller reservation price). The moderate and high willingness to pay curves would reflect a shift upwards of the low willingness to pay curve, with subsequent auction outcomes increasing financial gains to sellers.

5.1.1 THE SCENARIOS

The conceptual framework developed above was used to assess the potential financial benefits to consumers and prosumers from implementing a LEM under three different scenarios. In Scenario 1 consumers only pay the LEM auction price and prosumers receive the LEM auction price for local energy. The LEM price does not include network or market charges. In Scenario 2, both consumers and prosumers pay network and market charges for the energy they transact on the LEM. In Scenario 3, only consumers pay network and market charges for the electricity they transact on the LEM. Scenario 3 is most consistent with existing market arrangements.

It was also assumed a retailer was required to manage the LEM in each scenario, due to the requirement for a Financially Responsible Market Participant (FRMP) at each connection point under the existing framework. Based on billing data collected from 15 retailers a hypothetical retailer was created for modelling purposes to estimate the potential financial impacts of implementing a LEM on retailers who be currently obligated under the rules to manage a LEM.

With these considerations in mind the scenarios are described in more detail below.
5.1.1.1 SCENARIO 1

This scenario models the potential benefits of a LEM peer-to-peer business model that seeks to extend some of the benefits typically associated with residential solar generation to customers who may not have access to their own solar generation (due to rooftop space or financial reasons etc). The key benefits of residential solar for consumers are access to renewable electricity and the ability to reduce their energy costs through avoidance of volumetric network and market charges for the energy self-consumed. In this scenario the LEM extends these benefits to non-solar consumers who are not able to install their own solar generation. The way this is achieved is that consumers pay no network or market related costs for any electricity purchased on the LEM (under existing arrangements people with installed solar do not pay network and market charges for the energy they produce themselves).

Conceptually, this is how the theoretical benefits of local energy marketplace trading are often contemplated in the literature – buyers and sellers transact on the basis of the local market price, which sits somewhere below the retail price and above the minimum price required by the prosumer. Network and market costs still need to be recovered however, which means the retailer (or network business as the case may be) will need to recover those costs in some other way or fund these costs themselves.

5.1.1.2 SCENARIO 2

In this scenario, network and market costs are recovered equally from exports and imports. Under current arrangements these costs are applied solely to imports (consumers). This scenario is based on the notion that prosumers also benefit from using the network when exporting their electricity and so should contribute to the cost of transport. Prosumers also benefit from the electricity market and supporting environmental policies and should therefore contribute their fair share to the costs of these arrangements.

This scenario therefore models the implications of a c/kWh combined network plus market charge applied equally to both imports and exports. Compared to current arrangements (see Scenario 3 below) this means those buyers who choose to participate in the LEM will pay lower network and market costs because a proportion is now recovered from prosumers. Conversely, prosumers are asked to give up some of the benefits they currently derive from installing solar, and share these with customers who would otherwise not be able to access these benefits (noting that prosumers still benefit from avoidance of network and market charges for any electricity they self-consume).

The cost allocation arrangements tested in this scenario are likely the most desirable for the successful implementation of the LEM platform. This is because consumers and prosumers pay their fair share of using the network and the benefits and costs of local renewable energy are shared on a more equal basis between them, while ensuring that the retailer (or distribution business as the case may be), covers their costs.

An export charge cannot be implemented under current market arrangements, so it would require a change to the rules.
5.1.1.3 SCENARIO 3

This scenario reflects the allocation of network and market costs under existing arrangements. Network and market charges are currently recovered from consumption and generators only pay the cost of connection, they do not pay to use the network (no volumetric charges are applied to generator exports).

This scenario is the least desirable for consumers because purchases on the LEM will attract all the same network and market charges that currently apply to normal grid purchases. In this scenario non-solar customers (i.e. people without their own installed solar) continue to subsidise residential solar customers (i.e. people with installed solar).

The three scenarios are summarised in Table 1 below.

**Table 1: Summary of Cost Allocation Scenarios Applied in the Modelling**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Max WTP (price ceiling)</th>
<th>Min WTS (floor)</th>
<th>Auction clearing price</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Scenario 1</strong></td>
<td>Retail price (i.e. full retail c/kWh, but retailer ends up paying network charges)</td>
<td>FiT</td>
<td>1. Auction price is the midpoint between retail price and FiT 2. Auction price is 33.3% higher than midpoint 3. Auction price is 33.3% lower than midpoint</td>
<td>Would present a barrier to implementation if the losses a retailer suffers in the form of unfunded network and market charges exceed the customer retention or acquisition benefits</td>
</tr>
<tr>
<td><strong>Scenario 2</strong></td>
<td>Retail price minus ‘half’ the network and market costs usually paid by consumers (i.e. buyer and seller split the network and market fees associated with LEM trade)</td>
<td>FiT</td>
<td>1. Auction price is the midpoint between the ‘new’ retail price and FiT 2. Auction price is 33.3% higher than midpoint</td>
<td>This differs to current arrangements, where volumetric network and market costs are recovered from consumption only. Under existing arrangements generators do not pay to use the network (they only pay to connect to the network)</td>
</tr>
</tbody>
</table>
### Scenario 3
- Retail price minus the ‘full’ network and market costs (i.e. buyer pays all network costs associated with a P2P trade)
- **FiT**

| 1. | Auction price is the midpoint between ‘new’ retail price and FiT |
| 2. | Auction price is 33.3% higher than midpoint |
| 3. | Auction price is 33.3% lower than midpoint |

This reflects current arrangements where network and market costs are recovered from consumption only. This is in accordance with existing regulatory requirements and is the most immediately implementable option.

### 5.2 MODELLING ASSUMPTIONS

#### 5.2.1 DATA CHARACTERISTICS

The LVM target population comprised the Council areas of Latrobe City Council, Baw Baw Shire Council, Wellington Shire Council and South Gippsland Shire Council. There were 81 participants within these areas that signed consent forms allowing their historical energy meter data to be used for the feasibility modelling analysis. A full financial year (2017/18) of meter data was collected for each participant. Some participants (primarily dairy farmers) have more than one NMI, which meant the total number of NMIs (124) exceeded the number of participants (81). However, complete data sets were only available for 94 out of the 124 NMIs. The NMIs with incomplete data sets were excluded, giving a core participant group of 94 NMIs. These participants were designated as the LVM94.

The following key data points were extracted from the data population for the modelling:

1. Participant segment (residential, commercial, farm)
2. Connection information (NMI, meter number, feeder, location)
3. Electricity consumption data on a 30 minute basis from 1 July 2017 to 30 June 2018 (average load, peak load, total energy usage (peak and off-peak))
4. Solar PV generation data (installed capacity, peak generation, total annual generation)
5. Electricity tariff data (retail provider, usage tariffs [peak and off-peak], fixed charge, Feed-in-Tariff)

6. Network tariffs (tariff identifier, usage tariffs [peak and off-peak], fixed network charge)

7. Existing solar generation

Each LVM participant received a generic designation name (e.g. LVM001), to de-identify the data provided by participants. In some instances, full data sets were not made available and therefore were not considered in the detailed modelling stage. A 1 year time-series of 30 minute intervals was created specific to each member, reflecting each 30 minute interval as either a peak or off-peak tariff period.

Key energy information relating to each participant was extracted from bills, including the identity of the retail provider, tariffs and tariff structure, any applicable discounts, and the FiT.

CSV files for each participating NMI for the period 1 July 2017 to 29 June 2018 were obtained from AusNet Services (with participants’ signed consent). This data set included 30 minute interval usage data, as well as the 30 minute interval solar PV generation data for those participants with existing metered systems. For each 1 year time-series, the relevant key detail was extracted (total kWh usage peak, total kWh usage off-peak, kW, solar PV generation kWh, solar PV generation kW).

5.2.2 SOLAR GENERATION ASSUMPTIONS

Two levels of solar generation were also modelled as part of the feasibility study: existing solar and proposed solar. More details are available in Appendix F.

The existing solar generation scenario included all 94 participating NMIs, and any existing solar PV systems already installed to provide tradable energy on the local marketplace. The existing systems included a peak solar generation capacity of around 130kW, spread between 30 systems.

The proposed solar setting was modelled to look at the dynamics of the marketplace when there were more solar exports available for trading. The proposed solar generation includes all of the 94 participants, and any existing solar PV system installed, but also included the augmentation of solar PV generation throughout the LVM, assuming that those feasibility study participants who requested desktop solar proposals had those systems installed (noting that in practice, all of these systems would be required to go through a grid connection application with the Distribution Network Service Provider (AusNet Services). For the modelling however, this meant another 25 solar PV systems were added (to give a total of 55 systems within the group), with a peak additional generation capacity of around 182kW.

Under the existing solar generation there were limitations to the solar energy available to trade on the LEM, therefore results presented in Section 5.3 are the results modelled under the proposed solar generation scenario. Further details about both the existing solar generation data set, and the proposed solar generation data set are shown in Appendix F.

To estimate the amount of excess solar available for trading on the LEM a number of assumptions were made. First, the analysis assumes that excess solar is only made available for trading within the LEM where it is economically beneficial for the prosumers to do so. Where prosumers are already
receiving a very high FiT (20 c/kWh or above) it was assumed these prosumers would prefer to retain their existing arrangement with the retailer and were therefore excluded from the data set. There were 11 systems that receive a FiT of 20 c/kWh or more, approximately 13% of the overall volume exported to the grid.

 Tradable energy within the marketplace considered only the volume of energy generated that was less than or equal to the total net energy demand of all LEM participants, during every 30-minute period within the year. Therefore, any excess generation was excluded from the economic evaluation, and would yield only the stated FiT that was applicable (if there was no demand for the solar exports then there is no economic gain from making it available on the LEM).

For the solar PV analysis, it was assumed that in all cases, generated solar PV would be first used behind the meter before being exported to the local energy marketplace. This is because customers gain more financially from avoiding the retail tariff than they do from selling their energy to the retailer or the LEM. Therefore, the electricity available for trade on the LEM was the surplus electricity left over after self-consumption needs had been met.

As the feasibility study was focused on assessing the potential value of the LEM, it was further assumed that those customers requesting a desktop solar PV proposal as part of the project in fact had those systems installed and available for production. The larger the available volume of energy on the LEM, the greater the liquidity of trade and value of the LEM to its participants. Desktop proposals added a further 25 solar PV systems to the existing 30 systems or 182 kW of additional capacity. To estimate the level of solar generation and exports of the additional 25 solar installations, CommPower Industrial provided typical generation profiles of the systems as an input into the modelling.

5.2.3 COST OF PARTICIPATION IN THE LEM

There were several assumptions made about the cost of participation in a LEM. Participation does not require people to have their own solar installed or other type of DER. This is because for a LEM to function effectively there needs to be consumption as well, so not all participants need to be DER owners. Also, with a mix of different types of participants such as residential, commercial and farms, there is a diverse generation and consumption profile that maximises participation opportunities. As discussed in Section 5.2.2, some participants whose data was used in the modelling already had solar and some were interested in putting on solar and requested desktop proposals. These proposals were sized based on the best economic outcome for the resident/owner without the implementation of a LEM - i.e. on the basis that installation of solar made economic sense on a stand-alone basis (noting, of course, that acting in an economically rational way is not necessarily what all people do). The costs of installing solar and acquiring a network connection are not considered part of the costs of participation in an LEM. It is assumed instead that people make these decisions independently of whether they participate in the LEM or not. That is, the costs were assumed to be sunk and not influence future production or consumption decisions.

The costs of installing the software and hardware of the LEM have not been modelled, due to the high degree of uncertainty around the cost estimates. Such costs will vary significantly with the degree of scaling and the time period over which the fixed costs are recovered. They will also vary depending on the degree to which the LEM platform can be integrated with an existing retail
operating system. It is also feasible for a retailer to absorb the costs of participation if there are other commercial benefits observed, such as attraction of new customers, better retention of customers or access to customers for provision of other add-on services, such as home energy management.

The LEM costs will be explored with Simply Energy, the retail partner, during the implementation phase of the project – in particular the different ways in which these costs might be recovered (e.g. as a c/kWh transaction fee or subscription/access fee incorporated into the more general daily charge typically applied by a retailer to its customers).

5.2.4 DATA ANALYSIS

Siemens in-house software, PSS®DE, was used for modelling the scenarios. PSS®DE is a techno economic modelling tool which forecasts economic outcomes, taking into account technical considerations, such as network limits and time-of-use consumption and generation, allowing for an accurate representation of the energy flows and energy costs of the LVM participants included in the modelling. The sophisticated modelling software platform within PSS®DE allows the creation of a ‘digital twin’ of the LVM, ensuring highly accurate simulation of the technical and economic characteristics of each of the key stakeholders within the study: the consumers/prosumers, the network operators and the retailers.

The 2017-18 historical usage data for each LVM participant, the solar generation profiles and the tariff details were input into the PSS®DE model to simulate energy flows for the 12-month assessment period. The outputs of the simulation were the supply and demand balance between solar exports and demand for each 30-minute period during the assessment, thus creating a realistic techno-economic baseline of the LVM.

This information was then uploaded into an excel based financial model, to reflect each of the described scenarios, with the combination of PSS®DE outputs and the excel model allowing detailed analysis of the key information including:

1. Consumption and generation load profiles of each LVM participant (based on actual metered data from 1 July 2017 to 29 June 2018);
2. Time of Use (TOU) tariff structures, with a peak from 7am to 11pm weekdays and off peak at all other times).
3. An estimated solar PV generation profile for the 25 solar installations relating to the future solar proposals for those participants who chose to have this evaluated.
4. The current FiT for existing systems or an assigned standard FiT (for those proposed solar PV systems).
5. The LEM demand curves developed in Section 5.1.

The financial model was then run to test the economic outcomes available to participants by participating in the LEM under the different scenarios outlined in Section 5.1.1.
Using aggregated data sets of total available solar PV and individual energy demand, a model was created to assign each ‘buyer’ an energy volume in each of the 80 individual time periods (peak tariff period 7am to 11pm weekdays, off-peak tariff period 7am to 11pm weekends, and off-peak tariff period 11pm to 7am every day), based on the hypothetical demand curves. Where energy was available for trading, the participant having the highest demand bid, or willingness to pay, was first allocated their total energy demand for that period. The customer with the second highest bid then received the next allocation and so on until the full quantity of available solar PV for the 30 minute period had been exhausted.

Each time period was analysed in the same way, taking into account peak and off-peak period characteristics as applicable.

5.3 MODELLING RESULTS

Potential financial savings for LEM buyers and potential financial gains for prosumers selling their excess solar generation on the LEM are evaluated in each scenario relative to the counterfactual (current energy expenditures).

Before discussing the key results under each scenario, the current energy expenditure environment for the Latrobe Valley feasibility assessment participants is described in a little more detail below.

5.3.1 COUNTERFACTUAL ANALYSIS

The counterfactual represents what the LVM94 pay for their electricity under existing tariffs. Energy expenditure and tariffs paid by the LVM94 was analysed for the period July 2017 to June 2018. The detailed results of current expenditure and tariffs is contained in Appendix B.

Key features of the counterfactual are as follows:

1. The LVM94 had energy contracts with 16 different retailers and there was a wide variation in retail tariff rates, structures and plans

2. Feed in tariffs for existing solar systems ranged from 9.9 c/kWh to 72 c/kWh, with a median Fit of 11.5 c/kWh

3. The retail tariff component applying during peak times ranged from 14.8 c/kWh to 60.3 c/kWh, with a median rate of 28.7 c/kWh

4. The retail tariff component applying during off-peak times ranged from 10.1 c/kWh to 60.3 c/kWh, with a median rate of 16.5 c/kWh

5. The network tariff component applying during peak times ranged from 9.6 c/kWh to 38.0 c/kWh, with a median rate of 16.2 c/kWh

6. The network tariff component applying during off-peak times ranged from 3.6 c/kWh to 33.5 c/kWh, with a median rate of 3.8 c/kWh

The total expenditure of the LVM94 on electricity was $686,833 for the 2017/18 financial year, of which $577,930 (84%) was spent by farmers, $74,047 (11%) by residential customers and 5% by commercial customers. In terms of Time of Use tariffs, 51% of expenditure by the group occurred in
the peak period (7am to 11pm weekdays) while 42% occurred during off-peak periods, the remainder in shoulder periods. In terms of network costs, 93% of costs were recovered on a volumetric (c/kWh) basis while 7% of total costs were recovered as fixed costs ($kW charges).

The average kWh retail price paid by the LVM94 for electricity was 22 c/kWh. This comprises both regulated components and competitive market components. Regulated components are network charges, which make up 42% of costs, and market charges (comprising the costs of running AEMO and environmental schemes), which make up 13% of costs. Competitive sector costs (comprising retail costs and margin and wholesale costs) account for 45% of the overall retail tariff. Individual wholesale and retail components are commercially confidential and therefore can only be estimated.

The average cost of a kWh of consumption for a residential customer is 27.9 c/kWh, which is higher than the average for the farms (21.7 c/kWh) and the commercial customers at (21.0 c/kWh).

The LVM94 were predominantly on time of use (TOU) tariff. Its constituents are shown in Table 2 below for a de-identified residential and farming participant.

Table 2: Components of a typical residential and dairy farm TOU retail tariff

<table>
<thead>
<tr>
<th>Component</th>
<th>Residential customer</th>
<th>Dairy customer</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>c/kWh</td>
<td>% total</td>
</tr>
<tr>
<td>Environmental + AEMO fees</td>
<td>Peak</td>
<td>2.9</td>
</tr>
<tr>
<td></td>
<td>Off Peak</td>
<td>2.9</td>
</tr>
<tr>
<td>Network</td>
<td>Peak</td>
<td>17.5</td>
</tr>
<tr>
<td></td>
<td>Off peak</td>
<td>3.6</td>
</tr>
<tr>
<td>Wholesale + retail</td>
<td>Peak</td>
<td>8.8</td>
</tr>
<tr>
<td></td>
<td>Off peak</td>
<td>10</td>
</tr>
<tr>
<td>Standing charge</td>
<td>$412 (annual)</td>
<td>$635 (annual)</td>
</tr>
<tr>
<td>Total (variable) delivered tariff</td>
<td>Peak</td>
<td>29.2</td>
</tr>
<tr>
<td></td>
<td>Off peak</td>
<td>16.5</td>
</tr>
</tbody>
</table>

Note: Peak is 7am to 11pm weekdays

Table 2 illustrates that network charges tend to make up a larger proportion of the peak delivery price compared to the off peak, while the competitive segment components (the wholesale + retail component) make up a larger proportion of the off-peak. This indicates network businesses recover
more of their costs during peak times while retailers appear to recover more of their costs during off peak times.

Network businesses and retailers also recover a proportion of their overall costs as a fixed (standing) charge (typically $/month) applied to electricity bills. As noted, they make up only about 7% of overall charges across the LVM94 (which is typical of customers more broadly).

An important point to note from the table above is that residential and small business customers (including farms) will only have visibility over the total delivered tariff rather than its components.

5.3.2 SCENARIO 1 RESULTS - ALL PARTICIPANTS

To determine the economic value of the NEM, the ‘pay as bid’ action outcomes for each individual participant relative to their reservation price were summed across participants to arrive at an overall value for the LVM group (or more specifically for the subset of customers for whom it was economically beneficial to participate in the LEM). This was then compared to the counterfactual scenario to assess the potential economic gains and losses from participating in the LEM. The potential savings for a LEM buyer are the difference between the cost of electricity purchased on the LEM versus what would have been the cost of purchasing the equivalent volume under their existing retail contract.

In Scenario 1, the LEM outcomes were modelled under the assumption that neither consumers nor prosumers paid volumetric network and market charges for the volumes transacted on the LEM. The results are summarised in Figure 12 below. Detailed results are tabulated in Appendix C.

Figure 12: Financial gains and losses from trading on a Local Energy Marketplace, Scenario 1

The results for LEM buyers, LEM sellers and retailers are described separately below.

5.3.2.1 LEM BUYERS

Table 3: LEM buyer gains or losses for Scenario 1 relative to the counterfactual
Table 3 illustrates that under the counterfactual scenario, consumers would have paid $61,643 for their electricity at the normal retail price. At the LEM ‘pay as bid’ price the LVM94 paid $42,643 for this volume under a ‘moderate’ LEM clearing price (a saving of $19,000 or 31% on their equivalent volume paid under the retail tariff); they paid $48,989 under a ‘high’ LEM clearing price (a saving of $12,654 or 21%); and they paid $36,298 under a ‘low’ auction clearing price (a saving of $25,345 or 41%).

It was not economic for all of the LVM94 to make purchases on the LEM. There were 60 active buyers during the peak period (7am to 11 pm weekdays) and 75 active buyers during the off-peak period, with not all buyers overlapping. In total, 85 of the LVM94 were active buyers in the LEM.

There were 16 participants in the peak (7am to 11pm) and 12 participants in the off-peak who were willing to purchase more local energy but were unable to do so due to insufficient supply (even with the 25 additional solar installations assumed in the modelling).

Active LEM buyers purchased approximately 12% of their electricity from the LEM (the remainder continued to be sourced from the grid). This comprised 20% peak consumption and 6% off-peak consumption.

### 5.3.2.2 LEM SELLERS

Table 4: LEM Seller gains or losses for Scenario 1 relative to the counterfactual

<table>
<thead>
<tr>
<th>Seller Counterfactual ($)</th>
<th>Sales on the LEM ($)</th>
<th>Change in value ($)</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>23,644</td>
<td>Moderate clearing price</td>
<td>42,643</td>
<td>19,000</td>
</tr>
<tr>
<td></td>
<td>High clearing price</td>
<td>48,989</td>
<td>25,345</td>
</tr>
<tr>
<td></td>
<td>Low clearing price</td>
<td>36,298</td>
<td>12,654</td>
</tr>
</tbody>
</table>

Table 4 shows that prosumers selling into the LEM would have received $23,644 for the volume of electricity sold under the FiT (counterfactual scenario). At the volume weighted LEM price they received $42,643 under a moderate LEM clearing price (a gain of $19,000 or 80% over the counterfactual); they received $48,989 under a high LEM clearing price (a gain of $25,345 or 107%); and they received $36,298 under a low clearing price (a gain of $12,654 or 54%).

There were 42 active sellers in the LEM, of which 37 were also buyers of LEM energy.
5.3.2.3 RETAILER

Table 5: Retailer gains or losses for Scenario 1 relative to the counterfactual

<table>
<thead>
<tr>
<th>Retailer Counterfactual revenue ($)</th>
<th>Revenue lost due to LEM trading ($)</th>
<th>Retailer liability for network + market charges ($)</th>
<th>Retail margin (%)</th>
<th>Total loss ($)</th>
<th>Total loss (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>425,501</td>
<td>61,641</td>
<td></td>
<td>0.13</td>
<td>-8,013</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>34,418</td>
<td></td>
<td>-34,418</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td>-42,431</td>
<td>-10</td>
</tr>
</tbody>
</table>

Table 5 shows that under the counterfactual scenario, the hypothetical retailer would have received $425,501 in revenues from LEM buyers. Under LEM trading, however, the retailer received $363,860, losing $61,641 in revenue.

Wholesale costs, retailer costs and margin are confidential and specific to each retailer, so estimation of retailer losses required the imputation of a margin. Based on work done by the Grattan institute, the feasibility analysis assumed an average margin of 13% for the Victorian retailers supplying energy across the group. This equates to a loss in margin (profit) on that revenue of approximately $8,013.

Under Scenario 1, the retailer was also liable for the LEM equivalent volumetric network and market charges, which amounted to $34,418. The retailer therefore experienced a total financial loss of $42,431, which was a 10% financial loss compared to what they would have received from LEM participants under the counterfactual scenario. The retailer losses comprised both lost margin on the kWh that were traded on the LEM (rather than being purchased from the retailer) and the network and market costs they were required to fund on LEM participants behalf.

The potential retailer losses are the same regardless of whether a moderate, low or high auction outcome was achieved. This is because the volume traded and subsequent margin lost remains the same - it is only what the buyer pays the seller that changes with regard to each auction outcome.

5.3.2.4 SUMMARY OF OUTCOMES

The modelling shows that in aggregate, buyers could potentially achieve very substantial savings on their current energy costs. These savings are between 31% and 41% for energy purchased through the LEM, depending on whether high, moderate or low auction pricing outcomes were achieved for local energy (e.g. if LEM buyers are primarily motivated by saving money, then the low auction price outcome is the most relevant). Prosumers potentially achieved greater gains compared to buyers, increasing their sales revenues by between 53% and 107% as a group by selling local.

The reason for the significant economic gains for both consumers and prosumers in this scenario relative to the counterfactual scenario is that electricity purchased on the LEM did not attract network or market costs, which means significant savings for LEM buyers and also for LEM sellers.

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because buyers can offer a higher price for local energy (as their avoided costs are highest in this scenario).

Scenario 1 reflects a business model for the LEM that seeks to extend the benefits of residential solar to those consumers who may not have access to such benefits, due to lack of rooftop space, financial means, renting etc. However, in applying this model, retailers must continue to fund the network and the market related costs not paid by LEM participants for using the network.

The retailer potentially make approximately a 10% loss on the volumes its customers bought through the LEM. For the business model represented by Scenario 1 to be commercially feasible, these losses would need to be offset by gains made in other ways, such as avoiding churn or achieving higher prices on residual volumes (grid purchases made by LEM customers). Retailers could also apply a premium (such as an access fee or LEM price uplift) that recovers some of these costs.

It is an empirical matter whether the commercial benefits (of product bundling for example) associated with customer retention and acquisition will exceed the financial losses associated with underfunded network and market costs in this type of model. This issue will be examined with the partner retailer during the implementation phase of this project.

The relatively low level of overall LEM consumption and significant number of participants who were keen to purchase more local energy than was available suggests a material mismatch between when local energy was available and when it was desired for purchase. This is largely due to the rigid demand profiles of dairy farms, which comprise most of the consumption of the LVM cohort. Their demand is mostly early morning, late afternoon or early evening, when less solar generation is available. Approximately 80% of consumption on the LEM was from farmers. Detailed results are tabulated in Appendix C.

5.3.3 SCENARIO 2 RESULTS- ALL PARTICIPANTS

In Scenario 2, prosumers pay to use the network for their exports and thus are required to give up some of the benefits they achieve through self-consumption (imports and exports are treated symmetrically with respect to network and market costs). Under existing rules, prosumers do not currently pay for using the network to export their surplus solar generation. The results are summarised in Figure 13 below. Detailed results are tabulated in Appendix D.
The results for each category of participant are briefly discussed below.

5.3.3.1 LEM BUYERS

Table 6: LEM Buyer gains or losses for Scenario 2 relative to the counterfactual

<table>
<thead>
<tr>
<th>Buyer Counterfactual ($)</th>
<th>Cost of purchases on LEM ($)</th>
<th>Change in value ($)</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LEM Energy</td>
<td>61,097</td>
<td>Moderate clearing price 50,608</td>
<td>10,489</td>
</tr>
<tr>
<td></td>
<td></td>
<td>High clearing price 54,112</td>
<td>6,986</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Low clearing price 47,105</td>
<td>13,993</td>
</tr>
</tbody>
</table>

Table 6 shows that LEM participants, in aggregate, would have paid $61,097 for their electricity under their existing retail tariffs for the LEM equivalent volume. In contrast, they paid $50,608 for the volume they bought on the LEM assuming a ‘moderate’ LEM clearing price (a potential saving of $10,489 or 17.2% on the equivalent volume paid under the retail tariff); they paid $54,112 assuming a ‘high’ LEM clearing price (a potential saving of $6,968 or 11.4%); and they paid $47,105 under a ‘low’ auction clearing price (a potential saving of $13,993 or 22.9%).

The willingness to pay curves are lower in this scenario because consumers avoid fewer costs by participating in the LEM (unlike in Scenario 1, in Scenario 2 they have to pay network and market costs). This leads to lower auction pricing outcomes and fewer transactions. There were 79 active LEM participants in total (relative to 85 in Scenario 1).
As in Scenario 1, there were limitations in the market. There were just 16 buyers who could profitably purchase an additional 181,162 kWh from the LEM during the peak and 12 who could purchase an additional 90,433 kWh during the off-peak period, reflecting the mismatch between the demand of dairy farms and the available supply of solar generation.

The volume of energy purchased within the LEM is 12% of the total consumption of these 85 active participants (18.4% of peak consumption, 6.2% of off-peak consumption) with more than 80% of all consumption being bought by farmers.

5.3.3.2 LEM SELLERS

Table 7: LEM Seller gains or losses for Scenario 2 relative to the counterfactual

<table>
<thead>
<tr>
<th>Seller Counterfactual ($)</th>
<th>Sales on the LEM ($)</th>
<th>Change in value ($) (€)</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Moderate clearing price</td>
<td>17,658</td>
<td>-5,986</td>
<td>-18.2</td>
</tr>
<tr>
<td>High clearing price</td>
<td>21,162</td>
<td>-2,482</td>
<td>-7.5</td>
</tr>
<tr>
<td>Low clearing price</td>
<td>14,155</td>
<td>-9,489</td>
<td>-28.8</td>
</tr>
</tbody>
</table>

Table 7 illustrates that under the counterfactual scenario, sellers would have received $23,644 for their energy sold under the prevailing FiT. At the volume weighted LEM sale price they received $17,658 under a ‘moderate’ clearing price (a potential loss of $5,986 or -18% compared to the counterfactual scenario); they received $21,162 under a ‘high’ clearing price (a potential loss of $2,482 or -7.5%); and they received $14,155 under a low clearing price (a potential loss of $9,489 or -28%).

There were 42 energy sellers within the marketplace, of which 36 were also buyers.

Prosumers suffer financial losses relative to the counterfactual scenario by participating in this scenario because they are required to pay half the network and market charges for their exports compared to not paying any network and market charges under the counterfactual scenario.

5.3.3.3 RETAILER

Table 8: Retailer gains or losses for Scenario 2 relative to the counterfactual

<table>
<thead>
<tr>
<th>Retailer Counterfactual ($)</th>
<th>Revenue lost from LEM trading ($)</th>
<th>Retailer liability for network + market charges ($)</th>
<th>Retail margin (%)</th>
<th>Total loss ($) (€)</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>428,107</td>
<td>61,097</td>
<td>0</td>
<td>0.13</td>
<td>-7,943</td>
<td>-1.8</td>
</tr>
</tbody>
</table>

Table 8 shows that the retailer’s revenues for the LEM equivalent volume under the counterfactual scenario would have been $428,107. The retailer initially lost $61,097 (volume purchased on the LEM multiplied by the retail tariff) but recouped network plus market charges from both consumers and prosumers. The potential net loss to the retailer in this scenario related only to lost margin of $61,097 * 0.13 = $7,943 or 1.8% of revenues in the counterfactual scenario.

5.3.3.4 SUMMARY OF OUTCOMES
The modelling shows that, in aggregate, consumers potentially achieve savings on their current energy costs of between 11.4% and 17.2% compared to energy purchased through the LEM, with outcomes in this range depending on whether bid curves reflected a high, moderate or low auction outcomes.

On the other hand, prosumers potentially lose between -7.5% and -28.8% by participating in the LEM relative to the counterfactual scenario in this scenario. This is because prosumers are required to pay volumetric c/kWh network and market charges for their sales on the LEM. They are not required to pay these charges under the counterfactual scenario, so moving from to a LEM environment unsurprisingly entails overall losses for prosumers.

The retailer only lost their margin on volumes sold through the LEM, as both buyers and sellers fully fund network and market charges.

The core implication of Scenario 2 is that to participate in the LEM prosumers are required to give up some of the benefits of self-consumption and share these with LEM buyers. It is unlikely prosumers would voluntarily participate in the LEM if they lose financially from doing so. As a consequence, this scenario could only be implemented with a broader change to the National Electricity Rules (NER) to mandate a volumetric export charge for solar customers. A key risk with this approach, however, is that it could create incentives for solar customers to limit exports and install batteries, which would be counterproductive to the development of liquid LEMs.

An alternative approach to applying an export charge is to encourage network businesses to implement non-discriminatory cost-reflective tariffs for solar customers (which is discussed in more detail in Section 6.2.3). An example would be a peak demand charge ($/kW), which would encourage a more equitable sharing of the network costs between consumers and prosumers, since such a charge would no longer be volumetrically based. As discussed in 6.2.3, such a charge could also operate as a negative peak charge or rebate for prosumers who install batteries and export during peak times.

5.3.4 SCENARIO 3 RESULTS – ALL PARTICIPANTS

Scenario 3 reflects the implementation of the LEM under the existing cost allocation rules. Network and market costs continue to be recovered from consumption only. The results are summarised in Figure 14 below. Detailed results are tabulated in Appendix E.

**Figure 14**: Financial gains and losses from trading on a Local Energy Marketplace, Scenario 3
The results for each category of participant are briefly discussed below.

5.3.4.1 BUYERS

Table 9: LEM Buyer gains or losses for Scenario 3 relative to the counterfactual

<table>
<thead>
<tr>
<th>Buyer Counterfactual ($)</th>
<th>Cost of purchases on LEM ($)</th>
<th>Change in value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Energy</td>
<td>179,229</td>
<td></td>
</tr>
<tr>
<td>Moderate clearing price</td>
<td>34,206</td>
<td>3,461 (+9.2%)</td>
</tr>
<tr>
<td>LEM Energy</td>
<td>37,667</td>
<td></td>
</tr>
<tr>
<td>High clearing price</td>
<td>35,362</td>
<td>2,305 (+6.1%)</td>
</tr>
<tr>
<td>Low clearing Price</td>
<td>33,050</td>
<td>2,305 (+12.3%)</td>
</tr>
</tbody>
</table>

Table 9 illustrates that under the counterfactual scenario, active LEM participants paid in total $179,229 for their electricity. This is much lower than the total paid by LEM participants in Scenarios 1 and 2. The reason is that there were much fewer active LEM buyers in this scenario due to the lower reservation prices of buyers in this scenario (the avoided costs of participating in the LEM are lower).

For the LEM equivalent volume, buyers would have paid $37,667 under the counterfactual scenario, but paid $34,206 under a ‘moderate’ LEM clearing price (a potential saving of $3,461 or 9%); they paid $35,362 under a ‘high’ LEM clearing price (a potential saving of $2,305 or 6.1%); and they paid $33,050 under a ‘low’ auction clearing price (a potential saving of $2,305 or 12.3%).
Of the LVM94, there are 62 active participants trading energy within the local energy marketplace. There were 45 active buyers during the peak periods, 31 active buyers during the off-peak periods, and 46 buyers in total who are active P2P participants. Slightly fewer than half of the participants were, therefore, active buyers in the LVM. This is a lower number of participants compared with the other two scenarios.

The reason for this is that modelled demand bids (willingness to pay) is lowest in this scenario because the energy purchase costs avoided by participating in the LEM are only wholesale prices plus the retail margin. Buyers are still subject to all network and market related volumetric charges, which means they are willing to pay less for local energy.

Unlike Scenario 1 and 2 there were no buyers who could profitably purchase more electricity on the LEM in this scenario.

5.3.4.2 LEM SELLERS

Under the counterfactual scenario, sellers would have received $12,595 for their energy sold under the prevailing FiT. However, in Scenario 3 they received $16,056 under a ‘moderate’ clearing price (a potential gain of $3,461 or 27.5% compared to the counterfactual scenario); $17,212 under a ‘high’ clearing price (a potential gain of $4,617 or 36.7%); and $14,900 under a ‘low’ clearing price (a potential gain of $2,305 or 18.3%).

Table 10: LEM Seller gains or losses for Scenario 3 relative to the counterfactual

<table>
<thead>
<tr>
<th>Seller Counterfactual ($)</th>
<th>Sales on the LEM ($)</th>
<th>Change in value</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>($)</td>
</tr>
<tr>
<td>12,595</td>
<td>Moderate clearing price</td>
<td>16,056</td>
</tr>
<tr>
<td></td>
<td>High clearing price</td>
<td>17,212</td>
</tr>
<tr>
<td></td>
<td>Low clearing price</td>
<td>14,900</td>
</tr>
</tbody>
</table>

5.3.4.3 RETAILER

Outcomes for retailers are summarised in Table 11 below.

Table 11: Retailer gains or losses for Scenario 3 relative to the counterfactual

<table>
<thead>
<tr>
<th>Retailer Counterfactual ($)</th>
<th>Revenue lost from LEM trading ($)</th>
<th>Retailer liability for network + market charges ($)</th>
<th>Retail margin (%)</th>
<th>Total loss ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>179,229</td>
<td>37,666</td>
<td>0</td>
<td>0.13</td>
<td>-4,897</td>
</tr>
</tbody>
</table>

Table 11 shows that the retailer revenues under the counterfactual were $179,229. Initial revenue lost due to LEM trading was $37,666. However, the retailer recouped network and market costs from LEM buyers. This meant the retailer suffered only a potential net loss in margin of $37,666 * 0.13 = $4,897 or 2.7%.
5.3.4.4 SUMMARY OF OUTCOMES

The modelling shows that, in aggregate, consumers potentially save between 6% and 12% on energy purchased through the LEM, depending on whether bid curves reflect a high, moderate or low auction price outcome. While still making savings relative to the counterfactual scenario, savings are lowest for LEM buyers in this scenario. This is because LEM buyers’ avoided costs are lowest in this scenario (they fund all network and market costs regardless of whether they purchase their energy from the grid or from the LEM).

Prosumers benefit significantly in this scenario relative to the counterfactual scenario because they continue to avoid network and market related volumetric charges through self-consumption but they also benefit from obtaining higher compensation for their exports than they do under the current FiT.

5.4 A DEEPER LOOK INTO THE VALUE PROPOSITION FOR CUSTOMERS

This section provides consideration of the potential value proposition of the LEM on a more disaggregated basis. The results are shown for Scenario 3 only, as this represents the implementation of the LEM under existing market arrangements and is therefore the most realistic scenario for the near term. The cost of participation is discussed in more detail in Section 5.2.3, but it should be noted that the final structure and level of fees is something that will be further investigated during the implementation phase of the project.

5.4.1 FARMS

The 2018 CommBank Agri Insights\(^28\) report found that 81% of farmers (across the entire sector) say the cost of energy is a big concern and 91% of dairy farmers say they do not have any control over their energy costs. This feasibility analysis shows dairy farms can lower their energy costs by participating in the LEM.

The overall LVM consumption and exports were dominated by dairy farms because they comprised the largest loads of the project participants. Farms made up 54 of the National Metering Identifiers (NMIs) of the LVM94 data set. Farms consumed 62% of their total kilowatt hours in off-peak periods and 38% during peak hours. The average peak consumption retail rate for farmers was 30.5 c/kWh with a median value of 28.7 c/kWh. The average off-peak consumption rate was 19.0 c/kWh with a median value of 16.0 c/kWh. The average annual fixed costs were $512 with the median being $522.

The modelling outcomes for farms are summarised in Figure 15 below

Figure 15: Potential financial gains and losses for farms (Scenario 3)

Farmers, as a group, potentially saved between 6.3% and 12.7% on their annual energy expenditure by participating in the LEM, while dairy farms with solar potentially gained between 18.3% and 36.7% in extra energy revenue relative to exporting their electricity at the prevailing FiT. Like all participant classes, sellers benefited relatively more than buyers from the LEM. The modelling illustrates that turning dairy farms into local community generators could provide a new revenue stream for dairy farms as a mechanism for offsetting their energy cost.

Dairy farmers tend to have fairly rigid consumption profiles, due to their milking cycles. The shape of their demand profile (which is much more peaky than a residential profile) can be more challenging to hedge for retailers and therefore retail rates for dairy farmers are typically priced higher than for other commercial customers.

Further, the majority of a dairy farm’s demand occurs in early morning, late afternoon or early evening for milking, when there is minimal solar is available. Unless they install batteries, therefore, dairy farmers will continue to rely on the grid for the majority of their consumption needs and will derive value from solar primarily as an export revenue stream rather than from self-consumption.29

Consequently, for a LEM to deliver value for dairy farmers with solar power it would be important for there to be sufficient daily demand within the region to soak up the exports they produce, with export revenues thereby offsetting the consumption costs. During the LVM implementation phase, LO3 Energy intends to recruit some large council loads and other local businesses to enhance the available market for dairy farm solar exports.

5.4.2 COMMERCIAL CUSTOMERS

Of the LVM94 data set, only 4 of the NMIs are commercial. There was a larger group of commercial participants, but most of these NMIs were excluded from the group due to an incomplete data set (e.g. where there were multiple NMIs and all related retail bills were not sent). Commercial

29 Batteries can provide a viable commercial solution for some dairy farms but at current costs are economic in only in limited circumstances. The economics of batteries have not been modelled at part of this feasibility analysis.
participants are a key feature of a liquid local energy marketplace as they provide a different load profile to the average farm and residential participant. In particular, commercial customers tend to consume most of their electricity over daylight hours, which matches well with solar generation exports.

Within this small group, 61% of total kilowatt hours are consumed in off-peak periods, and 39% during peak hours (7am to 11pm weekdays). The average peak consumption rate for commercial participants was 28.7 c/kWh with a median value of 28.3 c/kWh. The average off-peak consumption rate is 19.4 c/kWh with a median value of 15.5 c/kWh.

The results for commercial customers are illustrated in Figure 16 below.

**Figure 16: Potential financial gains and losses for commercial customers (Scenario 3)**

![Figure 16](image-url)

Commercial prosumers and consumers potentially achieve substantive gains from participating in the LEM. They achieved slightly higher savings compared to dairy farms and residential customers through their LEM purchases, although this result should be considered with caution given the small sample size.

In its 2018 review of retail competition, the Australian Energy Market Commission (AEMC) noted that business customers faced real increases of 35% in their bills and a price increase of around 56% in real terms over the period from 2007–08 to 2017–18. The AEMC also found that very small business customers can pay more than a residential consumer when consuming the same amount of electricity. The subsection of commercial participants in the LVM94 is too small to be statistically significant, but the retail rates being paid by commercial participants are lower than those for both residential and farm customers.

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5.4.3 RESIDENTIAL CUSTOMERS

Of the LVM94 data set, 36 of the NMIs are residential. Within this group, 54% of total kilowatt hours are consumed in off-peak periods and 46% during peak hours. The average peak consumption rate for residential participants was 35.1 c/kWh with a median value of 35.8 c/kWh. The average off-peak consumption rate is 15.7 c/kWh with a median value of 15.1 c/kWh.

The modelling outcomes for residential consumers are illustrated in Figure 17 below.

Figure 17: Potential financial gains and losses for residential customers (Scenario 3, proposed solar)

Residential prosumers potentially gain very strongly under Scenario 3, while residential consumers potentially also benefit through substantive savings from participating in the LEM, particularly where auction outcomes are closer to the FiT floor price rather than the retail tariff price ceiling.

Residential consumers in Australia have faced a real increase of 35% in their bills and a price increase of around 56% in real terms over the period from 2007–08 to 2017–18. It is estimated that retailer costs and retailer margin contributed 23% to the increase in an average residential customer’s bill during that time. The feasibility analysis has shown that residential customers can make substantive savings on their energy costs by purchasing their electricity from the LEM and prosumers do even better. As additional capability and functionality is built into the LEM platform, additional value over and above peer-to-peer transactions will be available to consumers, because it will provide a channel into wholesale and ancillary services markets as well as providing a platform for grid services to local distribution businesses.

5.4.4 DISTRIBUTION NETWORK SERVICE PROVIDER

As noted in Section 4.1.3, the LEM platform will potentially create value for distribution network businesses, particularly in later phases when additional functionality is layered upon the peer to peer

energy trading capabilities. The LEM could operate as a platform to allow distribution businesses to advertise contracts for demand response or utilise price signals, such as a critical peak prices, to encourage consumers and prosumers to address congestion or network limitations through changes in behaviour. This could reduce or eliminate the need for future capital investments to resolve these issues. Under the existing network regulatory arrangements, network businesses can increase their profits by lowering their actual expenditures relative to forecasts over the five-year revenue cap period.

The LEM platform has the potential to encourage the efficient utilisation of the network. Network revenues for distribution businesses are expected to decline as the NEM becomes more decentralised and consumers increasingly seek to part-defect from the grid by installing solar and/or batteries for their own consumption.

The LEM platform can help reverse this trend by creating incentives for consumers to continue to utilise the network. It will allow consumers with DERs to deliver, and be compensated for, a range of services for the network. For example, a prosumer with a battery may have an incentive to take electricity from the grid at off-peak times when it is cheap (rather than use electricity stored in the battery at these times) and to then export the electricity stored in the battery at peak times, when those exports are valuable to the wholesale or ancillary services markets.

The LEM could signal this value by means of passing through a real time wholesale price or applying a critical peak price that compensates the battery owner for dispatch during the peak period. Provided the correct price signals are in place, the battery owner will have an incentive to use the network to maximise the value of their resource in the wholesale or ancillary services market. In turn, the distribution network business can charge the battery owner for the use of the network. Key to this approach is that the distribution business is allowed to set the operating parameters and an efficient network charge that appropriately reflects the benefits to the battery owner (or other DER provider) of using of the network in this way.

The same applies to a peer-to-peer transaction. If a consumer sees value in purchasing energy from the LEM and a prosumer sees value in selling onto the LEM, then they will enter into such transactions rather than seeking to supply their own electricity. The distribution business should be able to charge for the transport service it provides in such a transaction.

### 5.4.5 RETAILER

Retailers face a number of challenges in the current market environment, including high customer acquisition costs (CAC), low service margins and high churn rates, which lead to sub-par customer lifetime values (CLV) across most markets and segments. For example, referrals from some of the price comparison websites can cost up to $300 in commissions. Retailers typically need to hold customers for at least two years to cover the CAC. With an annual churn rate of 25-30% in the residential sector within Victoria\(^{33}\), this can have a significant impact.

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\(^{33}\) The switching rate in Victoria increased to 8% during the June 2018 quarter (from 7% in the previous quarter), and is anticipated to lift further during the first half of 2018–19 since during this
For retailers some of the potential benefits of implementing a Local Energy Marketplace could include:

- **Tools to improve customer engagement:** There is growing evidence that customers are looking for greater levels of engagement. Many retailers acknowledge they have outdated methods of maintaining customer relationships. This is particularly acute with large commercial and industrial (C&I) accounts, and responsiveness around risk management activities. Customers with a greater level of engagement are also less likely to switch. In fact, retailers with differentiated product offerings in a commoditised, competitive environment can deepen customer relationships and enhance CLV. Implementation of a LEM can also provide retailers with better data and analytics drawn from customer participation, which can offer insights into service upselling and new business model considerations.

- **Tools to improve customer experience:** despite this being the age of smartphones, few meaningful customer experience activities currently occur on mobile applications, although there are some notable exceptions. Customers receive either paper bills in the mail or emailed versions with, perhaps, an auto-pay function enabled with little to no information on what their energy spend went towards. Local energy trading between prosumers and consumers can enhance customer experience - for example, a customer can share surplus energy with people they want (e.g. family, friends, community, etc.) rather than selling back to the retailer.

- **Differentiated product offerings:** there is currently limited ability for retailers to differentiate on product, so they largely compete on cost and through brand marketing. The ability to offer a unique product or service can be meaningful in reducing CAC and can improve customer retention, which leads to an increase in CLV. Retailers are aware of customer shifts towards solar PV, energy storage and home energy management and with affordable electric vehicles on the horizon, retailers want to provide those services to replace falling revenues and maintain or establish themselves as the single point of contact for energy and home services. Local energy trading between prosumers and consumers can be included in this category as well, if limited retailers offer it. Some retailers are eager to provide customers with new options and new ways to procure energy through local sources.

Regarding the specific results of the LVM modelling, in all three scenarios the retailer potentially makes a loss compared to the counterfactual scenario. In both Scenario 2 and 3, the network and market charges are borne by the participants and the losses incurred by the retailer are the accumulated loss of margin on the volume of kilowatt hours traded on the LVM - a loss of 1.8% under Scenario 2 and 2.7% under Scenario 3.

Participation in an LEM, however, could boost customer engagement, reduce CAC by attracting new customers (under current regulations all participants in an LEM would need to be customers of the period Victorian households will be eligible to receive $50 if they use the Victorian Energy Compare website to compare available energy prices. Page 33, Annual Report on Compliance and Performance of the Retail Energy Market 2017-18, Australian Energy Regulator

same retailer), and improve CLV by retaining customers for longer and reducing churn. In addition, the LVM modelling shows that the majority of a customer’s electricity needs will continue to be made up of grid sourced electricity due to the mismatch between customer demand for electricity (mornings and evenings) and the main periods when solar generation is produced (daylight hours). This will change, however, as more batteries are installed over time.

The retailer therefore has the option to recoup losses caused by increased trading on the LVM platform with an increased mark-up on the balance of supply to their customers involved in the LVM. Also, if the LEM product becomes a point of differentiation for the retailer and increases its market share, the additional margin on overall volumes secured could offset the losses incurred on volume traded within the LEM.

The longer-term vision for the LEM could also provide additional value for retailers - e.g. as a mechanism for retailers to hedge their loads. The LEM could allow them to establish contracts with their customers as a way of dealing with a more volatile spot market brought about by increasing penetration of renewables, either through demand response or dispatchable batteries (providing a degree of behind the meter vertical integration).

The implementation phase will include metrics around customer retention and engagement for our partner retailer, Simply Energy, as well as economic outcomes for participants and the potential for the LEM to provide additional value to Simply Energy.

6 LEGAL AND REGULATORY FEASIBILITY

6.1.1 WHOLESALE MARKET ARRANGEMENTS

The National Electricity Market (NEM) is governed by the National Electricity Law (NEL) and National Electricity Rules (NER), covering:

- The operation of the competitive wholesale electricity market and the associated national electricity system
- The economic regulation of the services provided by monopoly transmission and distribution networks (primarily connection and transport)
- Provision of metering services (which from 1 December 2017 operates under a new competitive market framework)

The NER requires transactions in the NEM to be managed through the concept of a Financially Responsible Market Participant (FRMP). FRMPs have financial obligations in respect of their customers for energy sold or purchased through the wholesale spot market. An FRMP can be a registered Market Generator; a registered Small Generator Aggregator (SGA),35 a registered ‘Market

35 NER 2.3A, a business can register as a small generator aggregator if it wishes to combine the output of a number of small generating units and dispatch the collective output into the spot market. In essence, AEMO would treat the portfolio of small generators the same as a larger registered generator. All output produced by the portfolio must be dispatched into the spot market,
Customer’ (retailer or large customer); or a Market Network Service Provider (a business who owns and operates a part of the network on a commercial basis). Every connection point on the transmission or distribution network must have an FRMP associated with it, and only one FRMP is allowed per connection point.

Only one type of registered participant - a Market Ancillary Services Provider (MASP) - is currently not required to be a FRMP. A MASP can offer services provided by customers, such as demand response or dispatch of battery technology, into frequency control ancillary services (FCAS) markets. However, they need to contract with an FRMP, usually a retailer, to provide their services into the ancillary services market.

Specific responsibilities are allocated to a Market Customer FRMP under the NER. For example, a Market Customer must purchase all of its electricity from the spot market. It also has responsibilities to AEMO for making payments associated with consumption at each connection point for which it is the FRMP; for collecting network charges from customers on behalf of the distribution business; for managing interactions with Market Settlement and Transfer Solutions (MSATS) and for ensuring that there is a meter at each connection point with an associated National Metering Identifier (NMI).

A Market Generator FRMP also has a range of specific responsibilities, which include delivering all of its energy through the spot market and complying with dispatch and constraint management instructions from AEMO. A generator that sells its entire output to a retailer at the same connection point is not classified as a Market Generator, and therefore does not need to participate in the NEM. This provision captures Power Purchase Arrangements (PPA) between generators and large customers (or retailers) behind the meter (in private embedded networks, for example).

The wholesale market is supported by two types of financial market: an OTC market, where participants can hedge their wholesale purchases by means of bilateral contracts such as swaps, caps and options; and a futures market, where participants can enter into contracts for future purchases or sales using standardised products on an exchange.

The key policy and regulatory institutions that govern the NEM are: the Coalition of Australian Governments (COAG) Energy Council, which is responsible for setting the policy direction; the

and each generator must have its own connection point. Importantly, the concept of ‘generating unit’ is a term that has recently been introduced into the NER so as to include batteries in this definition.

36 See NER 2.4 for classification of market participants and 3.15.3 for which market participants are classified as FRMPs
37 NER 3.15.3
38 See NER 2.3.5. This provision may become an important revenue stream for battery owners in light of the AEMC’s recent decision to move the NEM from its current 30-minute settlement to 5-minute settlement from 1 July 2021, which will significantly enhance the value of batteries for fast demand side response (see AEMC 5-minute rule change proposal published on
39 NER 2.3.5
40 See NER 2.3.4
41 NER 7.2.1
42 NER 2.2.4(a)
Australian Energy Market Commission (AEMC), which has accountability for administering changes to the market rules; the Australian Energy Regulator (AER), which enforces the market rules; and the Australian Energy Market Operator (AEMO), which operates the wholesale market and has the responsibility for maintaining a reliable power system.

6.1.2 RETAIL MARKET ARRANGEMENTS

To supply electricity to customers in Victoria, a retailer must also be licensed by the Essential Services Commission (ESC) under the Electricity Industry Act 2000 (the EI Act). As part of their licence, retailers must comply with obligations under this Act.

The ESC is the independent economic regulator established by the Victorian Government to regulate energy. One of the ESC’s statutory functions is to administer the licensing of electricity distribution, generation, transmission and retailing activities. A person is prohibited from engaging in the sale or supply or generation or transmission of electricity unless that person holds a licence to undertake the activity or has received an exemption under Section 17 of the EI Act.43

Unlike most other states, the Victorian electricity market does not fall under the National Electricity Retail Rules (NERR). Instead, the key regulatory instrument that applies to retailers in Victoria is the Energy Retail Code (ERC)44 - but in general this follows the NERR closely, as the Victorian government undertook a process of harmonisation between the ERC and the NERR in 2014.

The Energy Retail Code covers:

- The relationship between retailers and their customers, including obligations to make standard offers, minimum contract terms and consent requirements for entry into contracts
- The relationship between distributors and customers, including standard contract terms
- Retailer licenses and exemptions to sell electricity and/or natural gas to customers
- Retailer of last resort arrangements
- Contents of a bill including frequency and bill smoothing requirements
- Payment difficulties and hardship
- Billing disputes
- Life support requirements

The retail price for energy that is paid by customers is currently not regulated in Victoria. This is set to change however, as the ESC is currently consulting on establishing a default retail price cap for

44 Energy Retail Code, Version 12, 1 January 2019
consumers. This is due for implementation in July 2019. Currently, retailers are required to offer customers both a 'standard offer contract' with model terms and conditions and a 'market retail contract', where retailers have more (but not complete) discretion to set the terms and conditions. While retailers have considerably more discretion with respect to market contracts, these are not completely free from regulation and also have a range of obligations associated with them (e.g. specific bill content requirements).

The Victorian licensing framework mirrors the broader consumer protections applying under the NERR and requires retailers to do the following (but not limited to):

- Develop and implement approved customer hardship policies to assist customers experiencing financial hardship and provide customers experiencing financial difficulty with flexible payment options
- Keep a register of customers who require energy-related life support equipment with added protections for disconnection of energy services
- Provide timely bills based on metered consumption and ensure that customers are provided with at least 13 business days to pay bills
- Comply with specific requirements around disconnections
- Have in place a dispute resolution mechanism for residential customers and participate in the relevant energy ombudsman scheme

In becoming a retailer, the ESC must also be satisfied that an applicant:

- Has the necessary organisational and technical capacity to operate as a retailer
- Has the financial resources, or access to resources, to operate as a retailer
- Is a suitable person to hold a retailer license
- Can demonstrate that it can meet the prudential requirements of AEMO (the ESC requires evidence of this before approving retail license)

In some limited cases, as set out in ESC’s General Exemption Order 17, a supplier of electricity and other services can operate under an exemption from the requirement to hold a retail licence. Examples of activities that may be exempt from the requirement to hold a licence include:

- Caravan parks, residential homes, multiple tenancy developments, shopping centres and holiday accommodation

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46 Energy Retail Code, p 15
47 See for example, Energy Retail Code, p 29
48 Energy Retail Code, p 60
• Solar power purchase arrangements, where a business provides, installs and maintains, at no initial cost, a solar panel system to a customer and in exchange, the customer buys the energy provided by the solar panels for an agreed price and for an agreed period

• Community-owned renewable energy projects where the sale, distribution and supply and generation of electricity is limited to a single site

• The generation of electricity in certain circumstances - e.g. where a customer is generating electricity for their own use through solar panels, with excess energy being sold to their licensed retailer.

6.1.3 RETAIL PRICING

The Victorian government is set to introduce a default retail price cap from July 1 2019 for residential customers. Currently retail prices are not regulated but are set in a competitive retail market. The retail price contains both regulated and competitively determined components.

The competitively determined components are: the wholesale price reflecting a retailer’s wholesale electricity purchase costs; the retail margin; and retail specific costs. The latter includes: marketing and acquisition costs; fixed and variable costs of setting up a retail operation; running call centres; and implementing retail billing systems, etc.

The regulated components include: geographically averaged network costs; the costs of environmental schemes to promote renewable generation (such as the Renewable Energy Target, solar FiT schemes and energy efficiency schemes); and the costs of running the wholesale market (fees collected by AEMO).

In Victoria, residential and small business consumers face a bundled price for their electricity. There is no visibility over the various components that make up the retail bill, such as the network or metering charges.

6.1.4 NETWORK CHARGING IN MORE DETAIL

Transmission and distribution charges relate to the use of the network and together they make up approximately 39% of the overall delivered price of electricity in Victoria. A key feature of the NEM is that only consumers of electricity pay for the actual use of the network (or more precisely retailers pay and then fully recover these costs from their customers). Generators only pay the up-front costs to connect to the network. They do not pay an ongoing fee to use the network (i.e. to export their generation). End use customers pay both the Transmission Use of System charges (TUOS) and the Distribution Use of System charges (DUOS), but do not pay for the up-front costs of connection.

In establishing their network charges, network businesses must now take into account the Pricing Principles in the NER. The pricing principles were reformed in 2016 to promote more cost reflective pricing by distribution businesses. The Pricing Principles require two separate components to be

49 ACCC, Retail Electricity Pricing Inquiry—Final Report, July 2018, p 35
50 NER, 6.18.5
included in the charge: a component that reflects an estimate of the efficient Long Run Marginal Cost (LRMC) \(^{51}\) of augmenting the network and a residual cost component, which recovers those costs not recovered by LRMC based charges which are primarily the sunk costs of existing network infrastructure.

The charge related to the LRMC relates to marginal costs expected to be incurred by a network business to meet demand growth within particular parts of the network. This is intended to signal to consumers the ‘avoidable’ costs of using the network – those costs a consumer can influence by changing their behaviour. For example, a Time of Use (TOU) tariff with a high peak versus off-peak component would be consistent with LRMC, because if sufficient customers respond to a high peak price by shifting their demand to off-peak times, this in turn reduces the need for future investment in the network.

The LRMC-based charge, however, only recovers an estimate of the future costs of expanding the network to meet peak demand, not the total costs of the poles and wires already in the ground. So the residual cost component is in place to recover the costs not recovered by LRMC based charges – primarily the sunk costs of existing network infrastructure.\(^{52}\)

The rules require that the residual costs are recovered in a way that does not influence consumption and therefore does not distort price signals. Network businesses typically recover these costs as a combination of a fixed component to the overall network charge (i.e. the standing charge) and an anytime volumetric c/kWh charge.

Distribution businesses are also required to consider customer impacts when setting their charges. Customers should be able to understand and respond to the charge and the charge should be relatively predictable and stable.\(^{53}\) Distribution businesses are required to submit their proposed tariff designs and indicative price levels in the form of a Tariff Structures Statement (TSS) to the Australian Energy Regulator (AER). The AER checks the TSS against the pricing principles and then approves them for implementation.\(^{54}\)

The TSS is a new reform (implemented at the same time as the new pricing principles) which was first applied for network businesses in the period 2017-18 to 2019-20. This period has seen distribution businesses gradually shift their tariff structures from consumption-based tariffs and declining block tariffs where electricity consumption becomes cheaper as it increases) to Time of Use (TOU) tariffs - which charges more for consumption in high-demand peak times and lower charges for consumption during lower-demand off-peak times – or Demand Charges – in which a $/kW charge is applied to a customer’s highest demand (or an average of their highest demands) during a specified period (e.g. each month over summer during the peak demand period).

\(^{51}\) NER, 6.18.5 (f) \\
\(^{52}\) NER, 6.18.5 (g) 3 \\
\(^{53}\) NER, 6.18.5 (h) and (i) \\
\(^{54}\) For more detail see: https://www.aer.gov.au/networks-pipelines/determinations-accesarrangements/pricing-proposals-tariffs?f%5B0%5D=type%3Aaccc_aer_tariff_structure
The most recently proposed network charges by AusNet Services typically come in two different forms. The first combines a TOU energy charge (c/kWh) with a fixed charge $/year applied for residential customers and small to medium enterprises. The second combine a demand based charge ($/kW) applied to a customer’s peak use during summer peak months between 3 pm and 9 pm with an annual fixed charge. \(^{55}\) The TOU-based charge is the one that applied to the vast majority of LVM customers.

Cost reflective network tariffs in the first TSS period (2017-18 and 2019-20) were offered on an ‘opt-in’ basis - and so far that has led to a slow uptake in Victoria. \(^{56}\) Victorian distribution businesses proposed an opt-out approach in the proposed TSSs they originally submitted to the AER, with a range of measures to assist customers with the transition. However, the Victorian government has instead implemented transitional opt-in rules for the first TSS period and these are due to be reviewed by the Victorian government before the second TSS period starts in Victoria in January 2021. \(^{57}\)

In summary, the current network charging arrangements provide a sound framework for implementing efficient cost reflective pricing, and the reason this has not been achieved to date appear largely to be due down to political reasons.

A final important aspect of the pricing arrangements is that network charges are bundled with the retail price and it is up to retailers to decide whether to pass the network tariff structure through. Those who are provided just the bundled price, therefore, don’t see the true cost to the network associated with their energy use.

### 6.2 REGULATORY BARRIERS TO THE LEM PLATFORM SERVICES

The core objective of the Local Energy Market (LEM) is to provide a market platform to develop new energy services, such as peer- to- peer trading, demand response and virtual power plants. However, existing regulatory barriers currently limit their implementation.

The project partners commissioned King and Wood Mallesons (KWM) to undertake detailed legal analysis of the key regulatory barriers for implementing the LEM in the Australian context. The detailed analysis is attached in Appendix I with key issues and conclusion of the report summarised below.

#### 6.2.1 PEER TO PEER ENERGY TRADING

A core objective of the LEM platform is to create a future environment where prosumers can sell surplus electricity directly to willing buyers without the need for a retailer intermediary. The intention of the LEM software platform is to rely on an auction mechanism, distributed ledger database and self-executing smart contracts to connect consumers and prosumers so that they, rather than a retailer, can determine the price, source and quantity of electricity produced and

\(^{55}\) AusNet, Electricity Distribution, Annual Tariff Proposal, 2019 p 62
\(^{56}\) AEMC, Economic Regulatory Framework Review, 2018 Final Report, p 111
\(^{57}\) Ibid, P 111
consumed within the LEM. The business model mirrors other peer-to-peer sharing platforms such as Uber and Airbnb.

The rationale for this is that the platform approach gives consumers greater scope to express their preferences and exercise control over how they use and source their energy, while at the same time bypassing some of the retailer and generator costs inherent in the normal pricing of electricity.

The success of peer-to-peer platform providers such as Uber and Airbnb are due largely to their ability to connect customers directly with one another and bypass many of the regulatory obligations that apply to service providers in their respective industries. However, whereas Uber and Airbnb can market directly to customers, who simply need to download an app to participate, this is not possible for electricity. The National Electricity Rules (NER) are significantly more complex compared to these other sectors and present inherent barriers to peer-to-peer transactions.

6.2.2 RETAIL MARKET

As discussed in Section 6.1.1, any consumption measured at a connection point must be allocated to a Market Customer FRMP and there must be separate Market Customer FRMPs for each individual connection point. Only a large customer or retailer can currently be classified as a Market Customer. In practice, what this means is that a consumer is only able to buy electricity from a retailer at a specific connection point (as opposed to buying directly from a consumer) and a prosumer is only able to sell electricity to that same retailer at the connection point. Peer-to-peer trading can therefore only be implemented by a retailer and only for those customers for whom it is already the FRMP.

This principle also applies more broadly to any other type of innovative energy service provided to a customer at a connection point. For example, the service of aggregating batteries for demand response or dispatch into wholesale or ancillary services markets as a virtual power plant can only be provided to a customer with the approval of a retailer and as a bundled product with that retailer’s core energy service. The same goes for a specialised tariff and supply bundle for EV charging. A business wishing to provide these innovative services would therefore need to partner with a retailer or become a retailer themselves.

The requirement for such bundling could limit competition, as it would force customers to contract with a single retail supplier for a range of services that could potentially be individually provided by different parties. This could also act as a barrier to the development of innovative business models such as peer-to-peer trading and EV charging, as access to customers for provision of these services is controlled by the retailer. Section 8.3.1 considers how this issue may be addressed.

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58 For example, UBER has to date managed to avoided restrictive regulatory requirements related to the terms and conditions of employment contracts that apply to taxicabs (Uber drivers are classified as independent contractors) and pricing requirements (cab fares are regulated). Airbnb avoids the taxes and regulations that apply to the hotel sector.
59 Market Customer is defined in Chapter 2 of the NER.
60 AEMC, Reliability Frameworks Review, 2018 Final Report, p 48
61 Ibid, p 48
6.2.3 NETWORK CHARGING

Current approaches to the recovery of network costs, in particular residual network costs across the NEM, also create a barrier to peer-to-peer trading on the LEM. Currently, recovery of network costs continues to be weighted heavily towards use of volumetric (c/kWh) approaches. This distorts price signals for peer-to-peer trading and the participation of those resources in wholesale and ancillary services markets because the market prices paid by consumers and received by prosumers are different. \(^{62}\)

The price prosumers receive for exported energy is less than the price they avoid paying by opting for self-consumption instead of purchasing electricity from their supplier. This means they will have strong incentives to focus their efforts on self-consumption and minimise the amount they export. This is mainly due to the reduced contributions made to network and market costs as a consequence of self-consumption, which allows volumetric network charges to be avoided. This incentive will only increase as the price of batteries comes down, as batteries will allow prosumers to extend self-consumption into the evening peaks.

Another important implication of distorted price signals created by asymmetric pricing is that as the NEM becomes more decentralised, the contribution to fixed and sunk cost recovery from consumers with rooftop solar and batteries will decrease further. This will force network businesses to increase charges on consumers without these resources to recover these costs. \(^{63}\)

As discussed in Section 6.1.4, in response to network pricing reforms implemented by the AEMC in 2016, the Victorian distribution businesses proposed implementation of peak demand charges on an opt-out basis for all consumers but were prevented from doing so by the Victorian government for the first TSS period.

A peak demand charge (ideally based on coincident peak demand) would support development of liquid LEMs and a fairer and more efficient recovery of network costs. Prosumers’ incentive to maximise self-consumption would be reduced with such a charge, because the costs they can avoid by doing so is lower (avoiding a $/kW charge would require installation of a battery). Such a charge would ideally be symmetrical, operating as a negative demand charge or rebate where the prosumer is exporting to the grid at peak times. \(^{64}\) This would support peer to peer trading at peak times while at the same time supporting a more efficient network. LO3 Energy is keen to explore more cost reflective tariffs as part of the second phase of this project, which seeks to implement sandbox arrangements for testing a number of the regulatory recommendations set out in Section 7.

6.2.4 ACCESS TO WHOLESALE ENERGY AND ANCILLARY SERVICES MARKET

\(^{62}\) For a good discussion of the issues see Darryl Biggar, “The Transformation of the Electricity Sector in Australia: The Public Policy and Competition Policy Issue”, Paper submitted for 63rd meeting of the OECD Working Party No. 2 on Competition and Regulation, 19 June 2017, p 10

\(^{63}\) See for example, https://www.greentechmedia.com/articles/read/this-is-what-the-utility-death-spiral-looks-like#gs.6Dy3OWU8

\(^{64}\) MIT, Utility of the future, “an MIT Energy initiative response to an industry in transition”, 2016, p 112
Energy is building capability into the LEM platform to allow a range of new energy services to be provided, not just peer-to-peer trading. For example, an aggregator or Australian Energy Market Operator (AEMO) could advertise contracts for wholesale or ancillary services, specifically targeting those LEM customers with the right characteristics (e.g. location, asset capability, etc). They could do this by sending a message to their apps. LEM prosumers could then self-organise into coalitions to fulfil those contracts at the right price, thus securing an additional source of value for their DERs. It is envisaged that the LEM platform would allow for a flexible and targeted approach for the use of DERs because a rich body of information about LEM participants would be developed over time and made accessible to AEMO, distribution businesses and aggregators.

There are, however, several barriers to DERs accessing wholesale and ancillary services markets, thus limiting their capacity to derive value from these services.

Firstly, the only mechanism currently available for LEM participants to access wholesale markets are the Small Generator Aggregator (SGA) provisions in part 2.3A of the NER. Under these provisions, a business can register as an SGA if it wishes to combine the output of a number of small generating units (which can include batteries) and dispatch the collective output into the spot market. In essence, AEMO would treat the portfolio of small generators the same as it would a larger registered generator. A key limitation of the SGA provisions, however, is that they require all output produced by the aggregated portfolio to be dispatched into the spot market. A future LEM member who wishes to access the wholesale market through the SGA provisions would not subsequently be able to participate in other markets under the existing rules - so this would prevent them from also selling their electricity on the peer-to-peer market or into the ancillary services market. This would constrain opportunities for LEM prosumer members to maximise the value of their DERs.

Secondly, DERs cannot currently access the ancillary services markets. Access to these markets requires a participant to register as a Market Ancillary Services Provider (MASP). A MASP can offer services provided by customers, such as demand response or dispatch of battery technology, into Frequency Control Ancillary Services (FCAS) markets. However, the rules currently do not allow for the aggregation of these services, which therefore excludes DERs from participating.

In addition to this, there are other restrictive NER requirements for DERs that relate to provision of ancillary services, in particular the requirement for ancillary services providers to have expensive ‘high speed’ metering and other equipment at each site to monitor and verify performance, which subsequently precludes DERs from providing these services.

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65 NER, 2.3A
66 See NER 2.3.5. This provision may become an important revenue stream for battery owners in light of the AEMC’s recent decision to move the NEM from its current 30-minute settlement to 5-minute settlement from 1 July 2021, which will significantly enhance the value of batteries for fast demand side response (see AEMC 5-minute rule change proposal published on
67 These requirements are captured by the MASS, which providers must adhere to in order to provide ancillary services (i.e. FCAS) in the NEM. It sets out the detailed specification for each of the market ancillary services and how a market participant’s performance is measured and verified when providing these services.
As discussed further in Section 8.3, the AEMC and AEMO are currently investigating ways to address the above issues.

6.3 CURRENT REGULATORY REFORM PROCESSES

There are a number of regulatory initiatives currently underway that could address some of the regulatory barriers identified above. These are considered in this section.

6.3.1 RETAIL MARKET

In its Reliability Frameworks Review (RFR) Final Report 2018, the AEMC proposed a new regulatory framework termed Multiple Trading Relationships (MTR). The aim of this is to better support the provision of demand response and other innovative energy services in the NEM. The MTR framework would define new categories of FRMP and introduce the concept of multiple trading relationships into the NER. This would allow third parties to become a FRMP and allow consumers to access multiple FRMPs at a single connection point while maintaining their existing retail relationship for their core energy supply. The proposed new framework and some of its key features are discussed in detail in the report produced by King Wood Mallesons (KWM), which appears in Appendix I.

The AEMC considers that allowing multiple energy service providers at the same connection point would promote consumer choice and competition in new energy services by allowing third parties, such as virtual power plants (SGAs) and demand response providers to provide services independently of retailers. This, the AEMC noted, would enable innovative new energy products and services to be introduced (such as the retailing of electric vehicle charge and discharge by car companies) as well as supporting the integration of increasing amounts of DERs into the network and wholesale markets.

A further key point noted by the AEMC in the RFR final report is that under multiple trading relationships the new party would only be responsible for a subset of a customer’s load, so the costs (e.g. prudential requirements) associated with this role should be less onerous than the costs of becoming a retailer for the whole of the load, as required under current arrangements. This would have the effect of lowering barriers to new entrant energy services providers and enhancing retail competition.

An MTR framework would allow the LEM platform and energy services provided by means of the LEM, such as peer-to-peer trading, VPPs and demand response, to be provided direct to customers, without the need for the approval of the Retailer FRMP. This would allow the LEM to be implemented as a fully decentralised market and allow for a more rapid scaling up of services provided by the LEM.

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68 AEMC, Reliability Frameworks Review, 2018 Final Report, available on AEMC website
69 AEMC, Reliability Frameworks Review, 2018 Final Report, pp 147-156
70 Ibid, p 49
71 Ibid, p 147
Multiple trading relationships would, however, require significant changes to regulatory frameworks and impose costs on market participants. For example, new rules would be needed for managing settlement in the wholesale market. A customer’s metered energy consumption would need to be split and allocated among a range of different energy service providers operating at each connection point, potentially requiring subtractive metering to be implemented. Further, with the potential of multiple retail suppliers operating at each connection point, regulation would also need to detail how responsibility for specific customer protections should be allocated and shared among retailers. An important question to be addressed is whether providers of energy services such as EV charging, demand response or peer-to-peer trading should have the same or lesser obligations than those currently applied to retailers.

These issues and the general benefits and costs of the MTR concept are best examined in a proof of concept trial, such as the LVM project.

The AEMC recently provided an interim advice to the Council of Australian Governments (COAG) Energy Council recommending the introduction of regulatory sandbox arrangements to create a more conducive framework for testing innovative new business models and evaluating the changes that need to be made to market rules to maximise their potential value. These proposed Sandbox arrangements would provide a very useful framework for testing the MTR concept through further trials, potentially as part of the LVM project.

6.3.2 WHOLESALE AND ANCILLARY SERVICES MARKET

AEMC and AEMO are investigating changes to frameworks to allow better access and enable the participation of DERs in wholesale and ancillary services markets and AEMO has initiated trials to test this. As part of the trials AEMO will initiate a consultation on the Market Ancillary Services Specification (MASS), which sets out the performance parameters, verification and other requirements that must be satisfied for a MASP to participate in ancillary services markets. In particular, this consultation is looking at whether there are aspects of the MASS that could be amended to facilitate and better value the provision of FCAS from new technologies including storage, VPPs and demand response.

The AEMC has recently commenced consultation on a demand response mechanism for operating in the wholesale market, which would provide an explicit compensation mechanism for aggregated demand response during demand peaks. The mechanism would pay participants the spot price for a demand reduction relative to an administered baseline. Similar schemes operate in California and

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72 Under subtractive or sub-metering a single settlement meter is retained but some loads are sub-metered and subtracted from the load at the settlement meter.
74 AEMC Interim Advice, Regulatory Sandbox Arrangements to support proof of concept trials, 7 March 2019
the Pennsylvania, Jersey, Maryland power pool (PJM). This could potentially provide an important future revenue opportunity for the LEM platform.

6.3.3 DISTRIBUTION SYSTEM OPERATOR MODEL

On June 15 2018, Energy Networks Australia and the Australian Energy Market Operator (AEMO) launched 'Open Energy Networks', a joint consultation seeking stakeholder input on how best to integrate DERs into Australia's electricity grid. It released an issues paper exploring three potential future models for managing distribution networks with a very high penetration of DERs:77

- **AEMO provides a single integrated platform**: AEMO would incorporate the dispatch of aggregations of DERs into power system optimisation, taking into consideration both local network limits and transmission network limits.

- **A two tiered approach in which distribution businesses optimise the dispatch of DERs before feeding into power system optimisation**: distribution businesses would manage the operation of individual DERs and aggregations of DERs in distribution level markets, ensuring the dispatch preferences of DERs would not breach local network limits. They would then feed a feasible dispatch schedule of aggregators into AEMO’s dispatch algorithm. This would essentially look like a virtual power plant or scheduled load at each transmission connection point. AEMO would then communicate dispatch targets at each transmission connection to the distribution businesses, which would then communicate signals to aggregators for dispatch.

- **An independent Distribution System Operator (DSO) optimises dispatch of DER**: an independent third party, referred to as a DSO, would take on the responsibility of optimising DER dispatch within distribution network technical limits. This model would separate the operation of distribution level markets from distribution investment and planning. This may involve establishing a separate DSO for each distribution network or a single DSO for the entire NEM.

In summary, each of the proposed models would, in essence, establish a distribution level market for DER services, with the key difference between the models being whether the DER optimisation function is best performed by AEMO, the network businesses or a third party Distribution System Operator (DSO).

The ‘Open Networks’ consultation is focused on creating a new regulatory and market framework for the operational management and trading of DER services (including demand response, aggregated generation and peer-to-peer). This could provide an important opportunity for scaling of the LEM platform.

LO3 Energy’s ultimate vision is for the LEM to develop into a distribution level transactive market place, where potential buyers of DER services (such a retailers, distribution businesses, AEMO, and

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77 AEMO and ENA “Open Energy Networks, Consultation Paper” 2018
customers through peer-to-peer transactions) compete to buy the services of DER providers at the best possible price, with the DER service provision flowing to its highest valued use.\textsuperscript{78}

The key deliverables of this ‘Open Networks’ consultation process are a ‘first steps, no regrets’ actions report and a comprehensive white paper. These are both due to be delivered in late 2019.

### 6.3.4 DATA ACCESS

The Australian Competition and Consumer Commission (ACCC) has recently commenced consultation on implementing a Consumer Data Right (CDR)\textsuperscript{79} for consumers and a data access framework for accredited data recipients (i.e. retailers, energy service providers, distribution businesses) in the energy sector.\textsuperscript{80} The consultation paper explores three models for allowing accredited data recipients to access customer data.\textsuperscript{81}

- **Model 1**: the AEMO centralised model - AEMO would be the sole data holder of a centralised data set (including consumer identity and billing information that it currently does not hold under national energy legislation) and would be responsible for providing CDR data directly to accredited data recipients

- **Model 2**: the AEMO gateway model - AEMO would provide a gateway function, acting as a pipeline for the provision of CDR data from data holders (which may include retailers and potentially also distributors) to accredited data recipients; they may also themselves be a data holder and thus provide CDR data directly to accredited data recipients

- **Model 3**: the economy wide CDR model - existing data holders (for example, retailers) would be responsible for providing CDR data directly to accredited data recipients and/or consumers, the same model used for the banking sector.

Model 2 is currently the preferred choice, but each will require a new communications infrastructure and APIs would need to be developed by AEMO, other data holders and data recipients for streamlined transfer of information between parties.

This consultation provides an important opportunity to develop an enhanced data access framework for third party energy service providers in the NEM.

\textsuperscript{78} AEMC, Distribution Market Model, Final Report, August 2017, P 26

\textsuperscript{79} The Consumer Data Right (CDR) provides individuals and businesses with a right to efficiently and conveniently access specified data in relation to them held by businesses. The CDR authorises secure access to this data by trusted and accredited third parties. The CDR requires businesses to provide public access to information on specified products they have on offer. CDR is designed to give customers more control over their information leading, for example, to more choice in where they take their business, or more convenience in managing their money and services

\textsuperscript{80} ACCC “Consumer Data Right in Energy, Consultation paper: data access models for energy data”, February 2019

\textsuperscript{81} Ibid, p 24
To support development of LEM platforms and other innovative business models, LO3 Energy outlines the following priority areas of regulatory reform based on the work of KWM, which is set out in detail in their report accompanying this feasibility analysis in Appendix I.

LO3 Energy considers the best approach to testing KWM’s recommendations is through a proof of concept trial, supported by a regulatory sandbox. The LVM project provides an opportunity for these arrangements to be implemented. LO3 Energy’s recommendations for further work, based on the KWM regulatory analysis are set out below.

### 7.1 RECOMMENDATION 1

**Investigate the benefits and costs of establishing a new Market Participant classification or classifications for ‘New Energy Service Providers’, covering services such as demand management, aggregations of DERs (also known as Virtual Power Plants or VPPs) and peer-to-peer trading.**

This recommendation is in line with recommendations made by the Australian Energy Market Commission (AEMC) in the Reliability Frameworks Review Final Report, in which they proposed trialling the concept of Multiple Trading Relationships (MTR). A key issue to be explored is whether the National Electricity Rules (NER) should define a new role or roles for New Energy Service Providers.

Further work should also consider whether the NER should be extended beyond the recent rule changes that established ‘Market Small Generation Aggregators’ (SGAs) and ‘Market Ancillary Service Providers’ (MASPs) to give the Australian Energy Regulator (AER) flexibility in categorising new market participants to enable the categories to keep pace with the changing nature of New Energy Service Providers.

### 7.2 RECOMMENDATION 2

**Investigate the benefits and costs of allowing consumers to contract with multiple service providers at the same connection point.**

This recommendation is also consistent with the AEMC’s recommendations in the Reliability Frameworks Review Final Report, which sought to allow multiple trading relationships at the same connection point. A key aspect of this will be to explore methods for sharing financial responsibility at a single connection point.

The allocation of responsibility for specific customer protections will also need review. An important question is whether new energy services, such as EV charging, demand response or peer-to-peer trading, should attract the same obligations as those applying to the core energy service.
7.3 **RECOMMENDATION 3**

**Develop a demand response mechanism to allow for demand response to be bid into the wholesale electricity market.**

Endorsing the AEMC’s current demand rule change consultation, this recommendation is for a demand management mechanism to be established and such that demand response aggregators are treated on equal footing to generators. It is also recommended that further consideration be given to potential options that could enable greater use of non-firm demand response.

7.4 **RECOMMENDATION 4**

**Investigate the benefits and costs of allowing the increased engagement and access of DERs to wholesale and ancillary services markets.**

This recommendation supports the AEMC’s recommendations in the Frequency Control Frameworks for proof of concept trials that explore rule changes to allow aggregators of DERs to effectively access ancillary services and wholesale markets. A critical aspect to address, however, is the need for aggregations of DERs to operate in these markets in a way that takes due account of local network conditions and limits.

An important aspect to test is whether existing rules relating to Market Ancillary Service Providers (MASPs) and Small Generation Aggregators (SGAs) should be amended to allow service providers to access both the wholesale market and the Frequency Control Ancillary Services (FCAS) market.

7.5 **RECOMMENDATION 5**

**Continue work on the development of a Distribution System Operator (DSO) model and evaluate the potential for distribution level markets that will allow trading of new energy services, such as demand response, aggregated generation and peer-to-peer, at the distribution level.**

This recommendation supports the work being done in the Open Energy Networks Consultation process, which is investigating different DSO models and the concept of distribution level markets to provide support for what will rapidly become a very complex distribution network and power system.

A key focus of ongoing work is to establish the best model for a DSO and whether the role is best performed by AEMO, the distribution business or a third party DSO.

7.6 **RECOMMENDATION 6**

**Facilitate data sharing between Market Participants, while maintaining privacy and confidentiality protections.**
This recommendation endorses the recently commenced ACCC consultation process for implementing a new CDR and data-sharing framework in the energy sector. It is recommended that the data-sharing framework be implemented and managed by AEMO.

7.7 RECOMMENDATION 7

Mandate opt-out cost-reflective pricing for networks and remove structural barriers for the uptake of cost-reflective pricing.

The AEMC has already enacted significant rule changes to network pricing in this regard, but there has been limited take up of the new model of network pricing because it is currently opt-in as opposed to opt-out. It is recommended that cost-reflective pricing is changed to an opt-out model and that State legislation which creates structural barriers to the uptake of locational based pricing be removed or amended.

Cost reflective pricing would transition consumers to more efficient pricing structures, such as peak demand charges, pass through of real time prices or critical peak pricing.

Implementing cost reflective pricing would remove cross subsidies between different types of customers, such as non-solar and solar customers, and encourage the more efficient use of the network.
APPENDIX A: SOLAR PROPOSALS TECHNICAL DETAILS

As described in Section 4.3.1 solar proposals were requested for 31 NMIs. Participants have been provided with the following proposed installations:

- 25 sites with solar and energy storage
- Three sites with solar only
- Three sites with energy storage only
- Three NMIs without any solar or energy storage
- Two different NMIs are repeated with different solar and storage combinations

Further high-level comments from AusNet Services regarding the proposed installations are shown in Table 12, including preliminary connection costs, or augmentation requirements.

**Table 12: Solar Proposal Technical Details High-Level Assessment**

<table>
<thead>
<tr>
<th>REF</th>
<th>Proposed annual export (kWh)</th>
<th>Proposed system capacity</th>
<th>Dist. Tx rating and phasing</th>
<th>No. Customers/installed DER capacity</th>
<th>Embedded generation grid connection application high level review</th>
</tr>
</thead>
</table>
| LVM018 | 12,027                       | 99.2 kW (59.2 kW solar and 40 kW battery) | 100 kVA, 3ph | 1/ 0 kW | As application >30kW and <1.5MW this will need to undergo a technical assessment by AusNet Services; this assessment is priced at $2,200.25 ex. GST. Reticulation should have 1x one common point of coupling. It is noted that the system capacity is at that of the transformer, therefore, it is anticipated that one of the following will need to take place:  
  - Proposed system capacity resized  
  - Site export limit  
  - Network augmentation |
<p>| LVM023 | 11,487 kWhr                  | 58.8 kW                  | 315 kVA, 3ph               | 1/0kW                               | A single phase inverter has been listed for a 3 phase connection – please rectify. |</p>
<table>
<thead>
<tr>
<th>REF</th>
<th>Proposed annual export (kWh)</th>
<th>Proposed system capacity</th>
<th>Dist. Tx rating and phasing</th>
<th>No. Customers/installed DER capacity</th>
<th>Embedded generation grid connection application high level review</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(AST comment: grid export max. allowable 189kW)</td>
<td>(34.8kW Solar and 24kW battery)</td>
<td></td>
<td></td>
<td>As application &gt;30kW and &lt;1.5MW this will need to undergo a technical assessment by AusNet Services; this assessment is priced at $2,200.25 ex. GST.</td>
</tr>
<tr>
<td>LVM055</td>
<td>3,035 kWhr</td>
<td>117.6kW (69.6kW solar and 48kW battery)</td>
<td>50kVA, 2ph</td>
<td>1/0kW</td>
<td>This site is listed as 2phase in AusNet Services systems; the maximum installed capacity of a system for 2 phase is 20kVA. The maximum allowable export for 2 phase is 10kVA (5 kVA per phase). This design needs to be reviewed</td>
</tr>
<tr>
<td>LVM059</td>
<td>531 kWhr</td>
<td>76.3kW (52.3 kW solar and 24kW battery)</td>
<td>50kVA, 3ph</td>
<td>1/0kW</td>
<td>The NMI provided is listed as a single phase connection; AusNet Services systems note 3 active phases; this design needs to be verified</td>
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<td></td>
<td>If 3 phase, the application is &gt;30kW and &lt;1.5MW and will need to undergo a technical assessment by AusNet Services; this assessment is priced at $2,200.25 ex. GST.</td>
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<td></td>
<td>Reticulation should have 1x one common point of coupling</td>
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<td>The proposed installed capacity is greater than that of the substation. It is anticipated that one of the following will need to take place:</td>
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<td></td>
<td></td>
<td></td>
<td>• Proposed system capacity resized</td>
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<td></td>
<td>• Site export limit</td>
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<td></td>
<td></td>
<td></td>
<td>• Network augmentation</td>
</tr>
<tr>
<td>LVM060</td>
<td>531 kWhr</td>
<td>52.9kW (28.9kW solar and 24kW battery)</td>
<td>100 kVA, 1ph</td>
<td>1/0kW</td>
<td>AusNet Services systems list this NMI and site as single phase; this design needs to be verified). For a single phase site the maximum allowance installed capacity is 10kVA with 5kVA export.</td>
</tr>
<tr>
<td>LVM061</td>
<td>531 kWhr</td>
<td>76.3kW (52.3kW solar and 24kW battery)</td>
<td>100 kVA, 3ph</td>
<td>2/0kW</td>
<td>Verify site reticulation is 3 phase.</td>
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<td></td>
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<td></td>
<td>The application is &gt;30kW and &lt;1.5MW and will need to undergo a technical assessment by AusNet Services; this assessment is priced at $2,200.25 ex. GST.</td>
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<td></td>
<td>Reticulation should have 1x one common point of coupling.</td>
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<td>It is anticipated that the following will be required</td>
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<tr>
<td>REF</td>
<td>Proposed annual export (kWh)</td>
<td>Proposed system capacity</td>
<td>Dist. Tx rating and phasing</td>
<td>No. Customers/installed DER capacity</td>
<td>Embedded generation grid connection application high level review</td>
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<td></td>
<td>Site export limit</td>
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</tbody>
</table>
| LVM062   | 33,327 kWh                   | 29.3 kW Solar only       | 25kVA, 3ph                  | 4/ YES                              | The NMI provided is listed as a single phase connection; AusNet Services systems note 3 active phases; this design needs verification. If 3 phase, the proposed installed capacity is greater than that of the substation. It is anticipated that one of the following will need to take place:  
• Proposed system capacity resized  
• Network augmentation |
| LVM069   | 708 kWh                      | Could not discern from info provided | 50kVA, 3ph | 1, 0kW | NMI is listed as single phase.AusNet Services’ systems denote 3 active phases; this design requires verification.  
Adequate information for review not supplied. |
| LVM070   | 858 kWh                      | Unknown (8.45kW solar and unknown battery) | 25, 2ph | 2/ YES | NMI is listed as single phase, however, AusNet Services’ systems denote two active phases; please confirm.  
Confirm proposed system capacity and inverter rating.  
SLD required to confirm proposed reticulation.  
The maximum installed capacity of a system for 2 phase is 20kVA. The maximum allowable export for 2 phase is 10kVA (5 kVA per phase). |
| LVM071   | 9 kWh                        | Unknown kW (12.4kW solar and unknown battery) | 25 kVA, 2ph | 2/ YES | Confirm proposed system capacity and inverter rating.  
SLD required to confirm proposed reticulation.  
The maximum installed capacity of a system for 2 phase is 20kVA. The maximum allowable export for 2 phase is 10kVA (5 kVA per phase). |
<table>
<thead>
<tr>
<th>REF</th>
<th>Proposed annual export (kWh)</th>
<th>Proposed system capacity</th>
<th>Dist. Tx rating and phasing</th>
<th>No. Customers/installed DER capacity</th>
<th>Embedded generation grid connection application high level review</th>
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</thead>
<tbody>
<tr>
<td>LVM072</td>
<td>1,018 kWhr</td>
<td>Unknown</td>
<td>10 kVA, 2ph</td>
<td>2/0kW</td>
<td>Confirm proposed system capacity and inverter rating.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(10.4kW Solar and unknown battery)</td>
<td></td>
<td></td>
<td>AusNet Services systems state this is a single phase site; design requires verification</td>
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<td>SLD required to confirm proposed reticulation.</td>
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<td>The maximum installed capacity of a system for single phase is 10kVA. The maximum allowable export is 5kVA.</td>
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<td>Proposed system, based on solar alone, greater than substation capacity.</td>
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<td>It is anticipated that one of the following will need to take place:</td>
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<td></td>
<td>• Proposed system capacity resized</td>
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<td></td>
<td>• Network augmentation</td>
</tr>
<tr>
<td>LVM073</td>
<td>929 kWhr</td>
<td>9.88kW</td>
<td>300 kVA, 3ph</td>
<td>117/YES</td>
<td>Confirm proposed system capacity and inverter rating.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(4.88 solar and 5kW battery)</td>
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<td>SLD required to confirm proposed reticulation.</td>
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<td>The maximum installed capacity of a system for single phase is 10kVA. The maximum allowable export is 5kVA.</td>
</tr>
<tr>
<td>LVM074</td>
<td>2,009 kWhr</td>
<td>7.8kW</td>
<td>50 kVA, 2ph</td>
<td>3/0kW</td>
<td>Confirm proposed system capacity and inverter rating.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(3.6kW solar and 4.2kW battery)</td>
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<td>SLD required to confirm proposed reticulation.</td>
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<td>The maximum installed capacity of a system for 2 phase is 20kVA. The maximum allowable export for 2 phase is 10kVA (5 kVA per phase).</td>
</tr>
<tr>
<td>LVM076</td>
<td>2,398 kWhr</td>
<td>7.1kW</td>
<td>300 kVA, 3ph</td>
<td>105/YES</td>
<td>Confirm proposed capacity and inverter rating.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(2.9kW solar and 4.2kW battery)</td>
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<tr>
<td>REF</td>
<td>Proposed annual export (kWhr)</td>
<td>Proposed system capacity</td>
<td>Dist. Tx rating and phasing</td>
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<td>SLD required to confirm proposed reticulation.</td>
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<td></td>
<td>The maximum installed capacity of a system for single phase is 10kVA. The maximum allowable export is 5kVA.</td>
</tr>
<tr>
<td>LVM078</td>
<td>1,593 kWhr</td>
<td>Unknown. (Confirm existing solar and 4.2kW battery)</td>
<td>100 kVA, 3 ph</td>
<td>24/ YES</td>
<td>Confirm proposed system capacity and inverter rating.</td>
</tr>
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<td>SLD required to confirm proposed reticulation.</td>
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<td></td>
<td>The maximum installed capacity of a system for single phase is 10kVA. The maximum allowable export is 5kVA.</td>
</tr>
<tr>
<td>LVM079</td>
<td>2,080</td>
<td>9.08kW (4.88kW solar and 4.2kW battery)</td>
<td>300 kVA, 3ph</td>
<td>58/ YES</td>
<td>Confirm proposed system capacity and inverter rating.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>SLD required to confirm proposed reticulation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>The maximum installed capacity of a system for single phase is 10kVA. The maximum allowable export is 5kVA.</td>
</tr>
<tr>
<td>LVM082</td>
<td>50,566</td>
<td>95.3kW (55.3kW solar and 40kW battery)</td>
<td>100 kVA, 3ph</td>
<td>1 / 0kW</td>
<td>As application &gt;30kW and &lt;1.5MW this will need to undergo a technical assessment by AusNet Services; this assessment is priced at $2,200.25 ex. GST.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Reticulation should have 1x one common point of coupling.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>It is anticipated that the following will be required</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Site export limit</td>
</tr>
<tr>
<td>LVM090</td>
<td>124 kWhr</td>
<td>88.6kW (56.6kW Solar and 32kW battery)</td>
<td>100 kVA, 3ph</td>
<td>1/0kW</td>
<td>As application &gt;30kW and &lt;1.5MW this will need to undergo a technical assessment by AusNet Services; this assessment is priced at $2,200.25 ex. GST.</td>
</tr>
<tr>
<td>REF</td>
<td>Proposed annual export (kWh)</td>
<td>Proposed system capacity</td>
<td>Dist. Tx rating and phasing</td>
<td>No. Customers/installed DER capacity</td>
<td>Embedded generation grid connection application high level review</td>
</tr>
<tr>
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<td>-------------------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Reticulation should have 1x one common point of coupling.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>It is anticipated that the following will be required</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Site export limit</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LVM094</td>
<td>8,035 kWh</td>
<td>98.8kW</td>
<td>50kVA, SWER 2ph</td>
<td>2/ YES</td>
<td>Connection type needs to be verified as may be SWER.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(58.8kW solar and 40kW battery)</td>
<td></td>
<td></td>
<td>The maximum installed capacity of a system for 2 phase is 20kVA. The maximum allowable export for 2 phase is 10kVA (5 kVA per phase). If a SWER then it is 3.5kVA per phase export.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>It is anticipated that one of the following will need to take place:</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Proposed system capacity resized</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Network augmentation</td>
</tr>
<tr>
<td>LVM096</td>
<td>124 kW</td>
<td>24.43kW</td>
<td>10 kVA, 2ph</td>
<td>3 / 0kW</td>
<td>Confirm proposed system capacity and inverter rating.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(9.43kW solar and 15kW battery)</td>
<td></td>
<td></td>
<td>AusNet Services systems state this is a single phase site; please confirm.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>SLD required to confirm proposed reticulation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>The maximum installed capacity of a system for single phase is 10kVA. The maximum allowable export is 5kVA.</td>
</tr>
<tr>
<td>LVM099</td>
<td>3,018 kWh</td>
<td>7.13kW</td>
<td>200 kVA, 3ph</td>
<td>79/ YES</td>
<td>Confirm proposed system capacity and inverter rating.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(2.93kW solar and 4.2kW battery)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LVM100</td>
<td>1,673</td>
<td>7.78kW</td>
<td>500 kVA, 3ph</td>
<td>112/ YES</td>
<td>Confirm proposed system capacity and inverter rating.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(3.58kW solar and 4.2kW battery)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LVM107</td>
<td>1,593 kWh</td>
<td>38.1kW</td>
<td>15 kVA, 2ph</td>
<td>3/ 0kW</td>
<td>NMI is listed as single phase, however, AusNet Services systems denote two active phases; please confirm.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(22.1kW and 16kW)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>REF</td>
<td>Proposed annual export (kWhr)</td>
<td>Proposed system capacity</td>
<td>Dist. Tx rating and phasing</td>
<td>No. Customers/installed DER capacity</td>
<td>Embedded generation grid connection application high level review</td>
</tr>
<tr>
<td>-------</td>
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<td>---------------------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Flywheel is a 3ph system, however, the supply to this site is 2ph. A formal technical connection application to AusNet Services is required; this assessment is priced at $2,200.25 ex. GST.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>The maximum installed capacity of a system for 2 phase is 20kVA. The maximum allowable export for 2 phase is 10kVA (5 kVA per phase).</td>
</tr>
<tr>
<td>LVM115</td>
<td>3,319 kWhr</td>
<td>2.6 kW solar only</td>
<td>50kVA, SWER 2ph</td>
<td>3 /YES</td>
<td>Connection type needs to be verified as may be SWER.</td>
</tr>
<tr>
<td>LVM115</td>
<td>2,274 kWhr</td>
<td>6.8kW</td>
<td>50kVA, SWER 2ph</td>
<td>3 / YES</td>
<td>Connection type needs to be verified as may be SWER.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(2.6kW solar and 4.2kW battery)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LVM116</td>
<td>3,920kWhr</td>
<td>78.8kW</td>
<td>50kVA, 3ph</td>
<td>1 / 0 kW</td>
<td>As application &gt;30kW and &lt;1.5MW this will need to undergo a technical assessment by AusNet Services; this assessment is priced at $2,200.25 ex. GST.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(46.8kW solar and 32kW battery)</td>
<td></td>
<td></td>
<td>Proposed system capacity is greater than that of the substation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>It is anticipated that one of the following will need to take place:</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Proposed system capacity resized with site export limit</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Network augmentation</td>
</tr>
<tr>
<td>LVM116</td>
<td>38,425 kWhr</td>
<td>48.8kW solar only</td>
<td>50kW, 3ph</td>
<td>1 / 0 kW</td>
<td>As application &gt;30kW and &lt;1.5MW this will need to undergo a technical assessment by AusNet Services; this assessment is priced at $2,200.25 ex. GST.</td>
</tr>
<tr>
<td>LVM116</td>
<td>2,159kWhr</td>
<td>73kW</td>
<td>50kVA, 3ph</td>
<td>1 / 0 kW</td>
<td>As application &gt;30kW and &lt;1.5MW this will need to undergo a technical assessment by AusNet Services; this assessment is priced at $2,200.25 ex. GST.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(41kW solar and 32kW battery)</td>
<td></td>
<td></td>
<td>Proposed system capacity is greater than that of the substation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>It is anticipated that one of the following will need to take place:</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Proposed system capacity resized with site export limit</td>
</tr>
<tr>
<td>REF</td>
<td>Proposed annual export (kWhr)</td>
<td>Proposed system capacity</td>
<td>Dist. Tx rating and phasing</td>
<td>No. Customers/installed DER capacity</td>
<td>Embedded generation grid connection application high level review</td>
</tr>
<tr>
<td>-------</td>
<td>-------------------------------</td>
<td>--------------------------</td>
<td>-----------------------------</td>
<td>-------------------------------------</td>
<td>---------------------------------------------------------------</td>
</tr>
<tr>
<td>LVM117</td>
<td>80kWhr</td>
<td>53.3kW (29.3kW solar and 24kW battery)</td>
<td>50kVA, 3ph</td>
<td>4/ YES</td>
<td>As application &gt;30kW and &lt;1.5MW this will need to undergo a technical assessment by AusNet Services; this assessment is priced at $2,200.25 ex. GST. Proposed system capacity is greater than that of the substation and there are other solar customers on the substation. It is anticipated that one of the following will need to take place: • Proposed system capacity resized with site export limit • Network augmentation</td>
</tr>
<tr>
<td>LVM119</td>
<td>19,460kWhr</td>
<td>152.9 kW (96.9kW solar and 56 kW battery)</td>
<td>100kVA, 30/ YES</td>
<td>As application &gt;30kW and &lt;1.5MW this will need to undergo a technical assessment by AusNet Services; this assessment is priced at $2,200.25 ex. GST. Connection type to be verified. Proposed system capacity is greater than that of the substation and there are other solar customers on the substation. It is anticipated that one of the following will need to take place: • Proposed system capacity resized with site export limit • Network augmentation</td>
<td></td>
</tr>
<tr>
<td>LVM122</td>
<td>2,159kWhr</td>
<td>Unknown. (Confirm existing solar and 5kW battery)</td>
<td>25kVA, 2ph</td>
<td>3/ 0kW</td>
<td>Confirm proposed system capacity and inverter rating. The maximum installed capacity of a system for 2 phase is 20kVA. The maximum allowable export for 2 phase is 10kVA (5 kVA per phase).</td>
</tr>
</tbody>
</table>
APPENDIX B: CURRENT EXPENDITURE AND TARIFF ANALYSIS

Further details and data points on current expenditure and network and retail tariffs from the LVM94 data set is provided in the tables below.

Table 13: Breakdown of Participant Numbers by Sector

<table>
<thead>
<tr>
<th></th>
<th>All LVM94</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>No of Members</td>
<td>94</td>
<td>36</td>
<td>54</td>
<td>4</td>
</tr>
</tbody>
</table>

Table 14: Breakdown of Total Spend by Sector and by Type of Cost

<table>
<thead>
<tr>
<th></th>
<th>All LVM94</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total $</td>
<td>% split</td>
<td>Total $</td>
<td>% split</td>
</tr>
<tr>
<td>Off-Peak Usage</td>
<td>291,839.24</td>
<td>42%</td>
<td>23,544.00</td>
<td>32%</td>
</tr>
<tr>
<td>Peak Usage</td>
<td>349,946.84</td>
<td>51%</td>
<td>35,094.35</td>
<td>47%</td>
</tr>
<tr>
<td>Fixed Costs</td>
<td>45,046.41</td>
<td>7%</td>
<td>15,408.88</td>
<td>21%</td>
</tr>
<tr>
<td>Total</td>
<td>686,832.49</td>
<td>11%</td>
<td>74,047.22</td>
<td>84%</td>
</tr>
</tbody>
</table>

In terms of the total spend on electricity amongst the group, 51% of the total spend occurs on variable consumption charges during peak periods, 42% occurs on variable consumption charges during off-peak periods, and 7% is fixed costs. The total electricity spend for the group, for the year of data assessed is $686,832. The bulk of that spend, 84% or $577,930, is from the 54 farm NMIs included in the group. The residential customer spend was $74,047, or 11% of the total.

Table 15: Breakdown of Total kWh Usage by Sector and Time of Use

<table>
<thead>
<tr>
<th></th>
<th>All LVM94</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total kWh</td>
<td>% split</td>
<td>Total kWh</td>
<td>% split</td>
</tr>
<tr>
<td>Off-Peak Usage</td>
<td>1,886,711.60</td>
<td>61%</td>
<td>142,359.09</td>
<td>54%</td>
</tr>
<tr>
<td>Peak Usage</td>
<td>1,204,820.54</td>
<td>39%</td>
<td>123,400.98</td>
<td>46%</td>
</tr>
<tr>
<td>Total</td>
<td>3,091,532.14</td>
<td>9%</td>
<td>265,760.06</td>
<td>86%</td>
</tr>
</tbody>
</table>

In the group, 61% of usage occurs during off-peak hours, and 39% occurs during peak hours. The farms participating also dominate in terms of consumption, accounting for 86% of total usage, residential participants accounting for 9% and commercial participants 5% of total consumption.
The average cost of a kilowatt hour across the LVMx94 group is 22.2 c/kWh, including a breakdown of 42% network charges, 13% compulsory market charges (i.e. AEMO pool fees, environmental charges) and 45% retailer charges (which includes wholesale costs, administration and margin). The average for a residential customer is 27.9 c/kWh, which is higher than the average for both the farms, 21.7 c/kWh, and the commercial customers at 21.0 c/kWh. Differences between off-peak and peak charges is broken down in more detail in Table 17 and Table 18 below.

### Table 16: Breakdown of Total per kWh Cost by Sector and Market Actor

<table>
<thead>
<tr>
<th></th>
<th>All LVM94</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>$/kWh (total)</td>
<td>% split</td>
<td>$/kWh (off-peak) % split</td>
<td>$/kWh (off-peak) % split</td>
<td>$/kWh (off-peak) % split</td>
</tr>
<tr>
<td>Network</td>
<td>0.09356</td>
<td>42%</td>
<td>0.118</td>
<td>42%</td>
</tr>
<tr>
<td>Market</td>
<td>0.02851</td>
<td>13%</td>
<td>0.0285</td>
<td>10%</td>
</tr>
<tr>
<td>Retailer</td>
<td>0.10009</td>
<td>45%</td>
<td>0.1321</td>
<td>47%</td>
</tr>
<tr>
<td>Average cost</td>
<td>0.22217</td>
<td></td>
<td>0.2786</td>
<td></td>
</tr>
</tbody>
</table>

The average cost of a kilowatt hour across the LVMx94 group is 22.2 c/kWh, including a breakdown of 42% network charges, 13% compulsory market charges (i.e. AEMO pool fees, environmental charges) and 45% retailer charges (which includes wholesale costs, administration and margin). The average for a residential customer is 27.9 c/kWh, which is higher than the average for both the farms, 21.7 c/kWh, and the commercial customers at 21.0 c/kWh. Differences between off-peak and peak charges is broken down in more detail in Table 17 and Table 18 below.

### Table 17: Breakdown of Off-peak kWh Cost by Sector and Market Actor

<table>
<thead>
<tr>
<th></th>
<th>All LVM94</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>$/kWh (off-peak) % split</td>
<td>$/kWh (off-peak) % split</td>
<td>$/kWh (off-peak) % split</td>
<td>$/kWh (off-peak) % split</td>
<td></td>
</tr>
<tr>
<td>Network</td>
<td>0.0421</td>
<td>27%</td>
<td>0.0486</td>
<td>29%</td>
</tr>
<tr>
<td>Market</td>
<td>0.02851</td>
<td>18%</td>
<td>0.0285</td>
<td>17%</td>
</tr>
<tr>
<td>Retailer</td>
<td>0.08407</td>
<td>54%</td>
<td>0.0883</td>
<td>53%</td>
</tr>
<tr>
<td>Average Off-Peak</td>
<td>0.15468</td>
<td></td>
<td>0.1654</td>
<td></td>
</tr>
</tbody>
</table>

The average price across off-peak periods is 15.4 c/kWh, with the average residential off-peak price being higher at 16.5 c/kWh then the farm price, 15.4 c/kWh, and 15.1 c/kWh for commercial members. Of the average off-peak price, 54% of the total is retailer charges, 18% is market costs, and 27% is network fees.

### Table 18: Breakdown of Peak kWh Cost by Sector and Market Actor

<table>
<thead>
<tr>
<th></th>
<th>All LVM94</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>$/kWh (peak) % split</td>
<td>$/kWh (peak) % split</td>
<td>$/kWh (peak) % split</td>
<td>$/kWh (peak) % split</td>
<td></td>
</tr>
<tr>
<td>Network</td>
<td>0.16542</td>
<td>57%</td>
<td>0.1648</td>
<td>58%</td>
</tr>
<tr>
<td>Market</td>
<td>0.02851</td>
<td>10%</td>
<td>0.0285</td>
<td>10%</td>
</tr>
<tr>
<td>Retailer</td>
<td>0.09653</td>
<td>33%</td>
<td>0.0911</td>
<td>32%</td>
</tr>
<tr>
<td>Average Peak</td>
<td>0.29046</td>
<td></td>
<td>0.2844</td>
<td></td>
</tr>
</tbody>
</table>

The average price across peak periods is 29.0 c/kWh, with the average peak price paid by farmers being higher at 29.2 c/kWh then the residential price, 28.4 c/kWh, and 27.3 c/kWh for commercial members. Of the average peak price, there is a flip compared to the off-peak period, in terms of
what makes up the charges with 57% of the total being network charges, and 33% retailer charges. Compulsory market costs are 10% of the average peak cost per kilowatt hour.

The average price across peak periods is 29.0 c/kWh, with the average peak price paid by farmers being higher at 29.2 c/kWh then the residential price, 28.4 c/kWh, and 27.3 c/kWh for commercial members. Of the average peak price, there is a flip compared to the off-peak period, in terms of what makes up the charges with 57% of the total being network charges, and 33% retailer charges. Compulsory market costs are 10% of the average peak cost per kilowatt hour.

Table 19: Breakdown of Fixed kWh Costs by Sector and Market Actor

<table>
<thead>
<tr>
<th></th>
<th>All LVM94</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$/kWh (fixed)</td>
<td>% split</td>
<td>$/kWh (fixed)</td>
<td>% split</td>
</tr>
<tr>
<td>Network</td>
<td>0.00341</td>
<td>23%</td>
<td>0.0155</td>
<td>27%</td>
</tr>
<tr>
<td>Retailer</td>
<td>0.01116</td>
<td>77%</td>
<td>0.0425</td>
<td>73%</td>
</tr>
<tr>
<td>Average Fixed Costs</td>
<td>0.01457</td>
<td></td>
<td>0.058</td>
<td></td>
</tr>
</tbody>
</table>

Both networks and retailers have fixed costs that are applied to electricity bills. In the case of networks this tends to be a charge covering infrastructure costs, such as poles and wires. In the case of retailers, there are fixed costs, such as the operation of a call centre, which are fixed, regardless of the number of customers. This cost tends to be split across an existing customer base. In the case of the LVMx94 77% of the fixed costs applied to customers is from the retailer, 23% charged by the network.
APPENDIX C: DETAILED SCENARIO 1 LEM RESULTS

A summary of the results for Scenario 1 was provided in Section 5.3.2. Full details of those results are shown in the tables below.

Table 20: Counterfactual expenditure for LEM participants

<table>
<thead>
<tr>
<th>All Energy</th>
<th>Total ($)</th>
<th>RESIDENTIAL ($)</th>
<th>FARM ($)</th>
<th>COMMERCIAL ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volumetric network and market charges paid by active LEM participants</td>
<td>227,878</td>
<td>30,199</td>
<td>184,286</td>
<td>13,393</td>
</tr>
<tr>
<td>Wholesale + retail component paid by active LEM participants</td>
<td>197,623</td>
<td>21,241</td>
<td>164,744</td>
<td>11,638</td>
</tr>
<tr>
<td>Total expenditure by active LEM participants</td>
<td>425,501</td>
<td>51,440</td>
<td>349,030</td>
<td>25,031</td>
</tr>
<tr>
<td>Total FiT revenues for active LEM sellers</td>
<td>24,458</td>
<td>5,577</td>
<td>18,329</td>
<td>553</td>
</tr>
</tbody>
</table>

Table 21: Total counterfactual volume for LEM participants and LEM volume traded for LEM participants

<table>
<thead>
<tr>
<th>Total energy traded (LEM participants)</th>
<th>Total</th>
<th>Residential</th>
<th>Farm</th>
<th>Commercial</th>
</tr>
</thead>
<tbody>
<tr>
<td>kWh</td>
<td>%</td>
<td>kWh</td>
<td>%</td>
<td>kWh</td>
</tr>
<tr>
<td>Peak</td>
<td>748,985</td>
<td>40.30%</td>
<td>98,116</td>
<td>13.10%</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>1,108,783</td>
<td>59.70%</td>
<td>131,860</td>
<td>11.90%</td>
</tr>
<tr>
<td>Total</td>
<td>1,857,768</td>
<td>100.00%</td>
<td>229,976</td>
<td>12.40%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Energy traded on LEM</th>
<th>Total</th>
<th>Residential</th>
<th>Farm</th>
<th>Commercial</th>
</tr>
</thead>
<tbody>
<tr>
<td>kWh</td>
<td>%</td>
<td>kWh</td>
<td>%</td>
<td>kWh</td>
</tr>
<tr>
<td>Peak</td>
<td>152,070</td>
<td>70.70%</td>
<td>23,539</td>
<td>15.50%</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>62,874</td>
<td>29.30%</td>
<td>10,719</td>
<td>17.00%</td>
</tr>
<tr>
<td>Total</td>
<td>214,945</td>
<td>100.00%</td>
<td>34,258</td>
<td>15.90%</td>
</tr>
</tbody>
</table>

* This is what LEM buyers ‘would have’ paid for LEM purchases or sellers would have received for LEM sales at the current retail price
### Table 22: LEM outcomes for consumers

<table>
<thead>
<tr>
<th>Buyer Counterfactual ($)</th>
<th>Cost of purchases on LEM ($)</th>
<th>Change in value ($)</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>61,643</td>
<td>Moderate clearing price</td>
<td>42,643</td>
<td>19,000</td>
</tr>
<tr>
<td></td>
<td>High clearing price</td>
<td>48,989</td>
<td>12,654</td>
</tr>
<tr>
<td></td>
<td>Low clearing price</td>
<td>36,298</td>
<td>25,345</td>
</tr>
</tbody>
</table>

### Table 23: LEM outcomes for prosumers

<table>
<thead>
<tr>
<th>Seller Counterfactual ($)</th>
<th>Sales on the LEM ($)</th>
<th>Change in value ($)</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>23,644</td>
<td>Moderate clearing price</td>
<td>42,643</td>
<td>19,000</td>
</tr>
<tr>
<td></td>
<td>High clearing price</td>
<td>48,989</td>
<td>25,345</td>
</tr>
<tr>
<td></td>
<td>Low clearing price</td>
<td>36,298</td>
<td>12,654</td>
</tr>
</tbody>
</table>

### Table 24: LEM outcomes for retailers

<table>
<thead>
<tr>
<th>Retailer Counterfactual revenue ($)</th>
<th>Revenue lost due to LEM trading ($)</th>
<th>Retailer liability for network + market charges ($)</th>
<th>Retail margin (%)</th>
<th>Total loss ($)</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>425, 501</td>
<td>61,641</td>
<td>0.13</td>
<td>-8,013</td>
<td></td>
<td></td>
</tr>
<tr>
<td>34, 418</td>
<td></td>
<td></td>
<td>-34, 418</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>-42,431</td>
<td>-10</td>
<td></td>
</tr>
</tbody>
</table>
APPENDIX D: DETAILED SCENARIO 2 LEM RESULTS

A summary of the results for Scenario 2 was provided in Section 5.3.35.3.2. Full details of those results are shown in the tables below.

Table 25: Counterfactual expenditure for LEM participants

<table>
<thead>
<tr>
<th>All Energy</th>
<th>Total ($)</th>
<th>RESIDENTIAL ($)</th>
<th>FARM ($)</th>
<th>COMMERCIAL ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volumetric network and market charges paid by active LEM participants</td>
<td>225,733.00</td>
<td>17,213.80</td>
<td>193,235.40</td>
<td>15,283.80</td>
</tr>
<tr>
<td>Wholesale + retail component paid by active LEM participants</td>
<td>202,373.50</td>
<td>17,921.70</td>
<td>174,938.30</td>
<td>9,513.50</td>
</tr>
<tr>
<td>Total expenditure by active LEM participants</td>
<td>428,106.50</td>
<td>35,135.50</td>
<td>368,173.80</td>
<td>24,797.30</td>
</tr>
</tbody>
</table>

| Total FiT revenues for active LEM sellers | 24,458 | 5,577 | 18,329 | 553 |

<table>
<thead>
<tr>
<th>LEM equivalent volume*</th>
<th>Total ($)</th>
<th>Total ($)</th>
<th>Total ($)</th>
<th>Total ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LEM traded volume: network and market cost component</td>
<td>32,949.90</td>
<td>2,645.10</td>
<td>28,564.60</td>
<td>1,740.10</td>
</tr>
<tr>
<td>LEM traded volume: wholesale + retail cost components</td>
<td>28,147.50</td>
<td>2,463.20</td>
<td>24,653.10</td>
<td>1,031.20</td>
</tr>
<tr>
<td>LEM traded volume: total expenditure</td>
<td>61,097.40</td>
<td>5,108.30</td>
<td>53,217.70</td>
<td>2,771.40</td>
</tr>
</tbody>
</table>

| Total FiT Revenue for Seller energy sold in to P2P market | 23,643.80 | 5,389.30 | 17,720.00 | 534.5 |

Table 26: Total counterfactual volume for LEM participants and LEM volume traded for LEM participants

<table>
<thead>
<tr>
<th>Total energy traded (LEM participants)</th>
<th>Total kWh</th>
<th>%</th>
<th>Residential kWh</th>
<th>%</th>
<th>Farm kWh</th>
<th>%</th>
<th>Commercial kWh</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>826,210</td>
<td>45</td>
<td>48,751</td>
<td>5.9</td>
<td>714,481</td>
<td>86.5</td>
<td>62,978</td>
<td>7.6</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>1,008,709</td>
<td>55</td>
<td>118,464</td>
<td>11.7</td>
<td>842,476</td>
<td>83.5</td>
<td>47,769</td>
<td>4.7</td>
</tr>
<tr>
<td>Total</td>
<td>1,834,918</td>
<td>100</td>
<td>167,215</td>
<td>9.1</td>
<td>1,556,957</td>
<td>84.9</td>
<td>110,746</td>
<td>6</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Energy traded on LEM</th>
<th>Total kWh</th>
<th>%</th>
<th>Residential kWh</th>
<th>%</th>
<th>Farm kWh</th>
<th>%</th>
<th>Commercial kWh</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>152,070</td>
<td>70.7</td>
<td>10,211.50</td>
<td>6.72</td>
<td>133,857</td>
<td>88</td>
<td>8,002.60</td>
<td>5.3</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>62,874</td>
<td>29.3</td>
<td>9,869.40</td>
<td>15.7</td>
<td>50,315</td>
<td>80</td>
<td>2,690</td>
<td>4.3</td>
</tr>
<tr>
<td>Total</td>
<td>214,944</td>
<td>100</td>
<td>20,081</td>
<td>9.3</td>
<td>184,171</td>
<td>86</td>
<td>10,692</td>
<td>5</td>
</tr>
</tbody>
</table>
Table 27: LEM outcomes for consumers

<table>
<thead>
<tr>
<th>Buyer Counterfactual ($)</th>
<th>Cost of purchases on LEM ($)</th>
<th>Change in value ($)</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>61,097</td>
<td>Moderate clearing price</td>
<td>50,608</td>
<td>10,489</td>
</tr>
<tr>
<td></td>
<td>High clearing price</td>
<td>54,112</td>
<td>6,986</td>
</tr>
<tr>
<td></td>
<td>Low clearing price</td>
<td>47,105</td>
<td>13,993</td>
</tr>
</tbody>
</table>

Table 28: LEM outcomes for prosumers

<table>
<thead>
<tr>
<th>Seller Counterfactual ($)</th>
<th>Sales on the LEM ($)</th>
<th>Change in value ($)</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>23,644</td>
<td>Moderate clearing price</td>
<td>17,658</td>
<td>-5,986</td>
</tr>
<tr>
<td></td>
<td>High clearing price</td>
<td>21,162</td>
<td>-2,482</td>
</tr>
<tr>
<td></td>
<td>Low clearing price</td>
<td>14,155</td>
<td>-9,489</td>
</tr>
</tbody>
</table>

Table 29: LEM outcomes for retailers

<table>
<thead>
<tr>
<th>Retailer Counterfactual ($)</th>
<th>Revenue lost from LEM trading ($)</th>
<th>Retailer liability for network + market charges ($)</th>
<th>Retail margin (%)</th>
<th>Total loss ($)</th>
<th>(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>428,107</td>
<td>61,097</td>
<td>0</td>
<td>0.13</td>
<td>-7,943</td>
<td>-1.8</td>
</tr>
</tbody>
</table>
Appendix E: Detailed Scenario 3 LEM Results

A summary of the results for Scenario 3 was provided in Section 5.3.4. Full details of those results are shown in the tables below.

Table 30: Counterfactual expenditure for LEM participants

<table>
<thead>
<tr>
<th>All Energy</th>
<th>Total ($)</th>
<th>RESIDENTIAL ($)</th>
<th>FARM ($)</th>
<th>COMMERCIAL ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volumetric network and market charges paid by active LEM participants</td>
<td>79,672.2</td>
<td>8,864.6</td>
<td>70,499.0</td>
<td>308.6</td>
</tr>
<tr>
<td>Wholesale + retail component paid by active LEM participants</td>
<td>99,556.4</td>
<td>8,659.5</td>
<td>90,429.1</td>
<td>467.9</td>
</tr>
<tr>
<td>Total expenditure by active LEM participants</td>
<td>179,228.6</td>
<td>17,524.1</td>
<td>160,928.1</td>
<td>776.5</td>
</tr>
</tbody>
</table>

Total FiT revenues for active LEM sellers | 24,458.3 | 5,576.5 | 18,328.9 | 553.0 |

LEM equivalent volume*

<table>
<thead>
<tr>
<th>LEM traded volume: network and market cost component</th>
<th>Total ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>18,149.70</td>
<td>1,936.40</td>
</tr>
<tr>
<td>16,097.08</td>
<td>20.77</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>LEM traded volume: wholesale + retail cost components</th>
<th>Total ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>19,517.14</td>
<td>1,713.27</td>
</tr>
<tr>
<td>17,660.00</td>
<td>20.77</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>LEM traded volume: total expenditure</th>
<th>Total ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>37,666.85</td>
<td>3,649.67</td>
</tr>
<tr>
<td>33,757.09</td>
<td>20.77</td>
</tr>
</tbody>
</table>

Total FiT Revenue for Seller energy sold in to P2P market | 12,594.94 | 2,878.46 | 9,431.68 | 284.80 |

Table 31: Total counterfactual volume for LEM participants and LEM volume traded for LEM participants

<table>
<thead>
<tr>
<th>Total energy traded (LEM participants)</th>
<th>Total kWh</th>
<th>Residential %</th>
<th>Farm %</th>
<th>Commercial %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>301,385.5</td>
<td>48.6</td>
<td>12.3</td>
<td>87.3</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>319,377</td>
<td>51.4</td>
<td>6.9</td>
<td>92.7</td>
</tr>
<tr>
<td>Total</td>
<td>620,762.5</td>
<td>100</td>
<td>9.5</td>
<td>90.1</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Energy traded on LEM</th>
<th>Total kWh</th>
<th>Residential %</th>
<th>Farm %</th>
<th>Commercial %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>86,128</td>
<td>75.2</td>
<td>10.4</td>
<td>89.6</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>28,372</td>
<td>24.8</td>
<td>8.4</td>
<td>90.5</td>
</tr>
<tr>
<td>Total</td>
<td>114,500</td>
<td>100</td>
<td>9.9</td>
<td>89.4</td>
</tr>
</tbody>
</table>
### Table 32: LEM outcomes for consumers

<table>
<thead>
<tr>
<th>Buyer Counterfactual ($)</th>
<th>Cost of purchases on LEM ($)</th>
<th>Change in value ($%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>37,667</td>
<td>Moderate clearing price</td>
<td>3,461 (+9.2)</td>
</tr>
<tr>
<td>34,206</td>
<td></td>
<td></td>
</tr>
<tr>
<td>High clearing price</td>
<td>35,362</td>
<td>2,305 (+6.1)</td>
</tr>
<tr>
<td>Low clearing price</td>
<td>33,050</td>
<td>2,305 (+12.3)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Table 33: LEM outcomes for prosumers

<table>
<thead>
<tr>
<th>Seller Counterfactual ($)</th>
<th>Sales on the LEM ($)</th>
<th>Change in value ($%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>12,595</td>
<td>Moderate clearing price</td>
<td>16,056</td>
</tr>
<tr>
<td>High clearing price</td>
<td>17,212</td>
<td>4,617 (+36.7)</td>
</tr>
<tr>
<td>Low clearing price</td>
<td>14,900</td>
<td>2,305 (+18.3)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Table 34: LEM outcomes for retailers

<table>
<thead>
<tr>
<th>Retailer Counterfactual ($)</th>
<th>Revenue lost from LEM trading ($)</th>
<th>Retailer liability for network + market charges ($)</th>
<th>Retail margin (%)</th>
<th>Total loss ($)</th>
<th>Total loss (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>179,229</td>
<td>37,666</td>
<td>0</td>
<td>0.13</td>
<td>-4,897</td>
<td>-2.7</td>
</tr>
</tbody>
</table>
Two levels of solar generation were also modelled as part of the feasibility study: existing solar systems only, and proposed solar, which also included PV systems that participants had requested solar proposals for. Details of the two data sets are shown below.

**EXISTING SOLAR**

The existing solar generation scenario included all 94 participating NMIs, and any existing solar PV systems installed to provide the P2P market energy. The existing system included a peak solar generation capacity of around 130kW, between 30 systems.

**Table 35: Total Exported Solar (kWh), Existing Solar**

<table>
<thead>
<tr>
<th></th>
<th>Total (kWh)</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>65503.9</td>
<td>37766.7</td>
<td>24488.5</td>
<td>3248.6</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>24241.2</td>
<td>14249.4</td>
<td>8707.1</td>
<td>1284.7</td>
</tr>
<tr>
<td>TOTAL</td>
<td>89745.1</td>
<td>52016.1</td>
<td>33195.6</td>
<td>4533.4</td>
</tr>
</tbody>
</table>

Table 40 above shows the breakdown of total exported solar from installed, or existing solar systems by period. Approximately 58% of all available exported kilowatt hours come from residential participants. 17 of the existing systems are residential and 12 of the existing systems are on farms. As would be expected, the bulk of the exports (73%) are during peak periods.

**Table 36: Available Solar Energy for Trading on the Local Energy Marketplace, Existing Solar**

<table>
<thead>
<tr>
<th></th>
<th>Total (kWh)</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>43612.1</td>
<td>28333.7</td>
<td>12029.7</td>
<td>3248.6</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>15823</td>
<td>10701.9</td>
<td>3836.4</td>
<td>1284.7</td>
</tr>
<tr>
<td>TOTAL</td>
<td>59435.1</td>
<td>39035.7</td>
<td>15866.1</td>
<td>4533.4</td>
</tr>
</tbody>
</table>

Table 41 shows the volume of exported solar energy that is available to be traded on the local energy marketplace. Solar energy is only made available for trading where it is economically beneficial for that to take place. This volume therefore excludes any exports that currently receive high feed-in-tariffs, which is shown in Table 42 below.

**Table 37: Solar Energy Not Available for Trading Due to High Feed-in-Tariff, Existing Solar**

<table>
<thead>
<tr>
<th></th>
<th>Total (kWh)</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>21891.8</td>
<td>9433</td>
<td>12458.8</td>
<td>0</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>8418.2</td>
<td>3547.5</td>
<td>4870.7</td>
<td>0</td>
</tr>
<tr>
<td>TOTAL</td>
<td>30310</td>
<td>12980.5</td>
<td>17329.5</td>
<td>0</td>
</tr>
</tbody>
</table>
The total volume of kilowatt hours that are not traded due to a high feed-in-tariff is 12.9% of the total volume of exported kilowatt hours. There are 11 systems that receive FiTs of 20 c/kWh and above, with most (9 out of 11) receiving a FiT of 60c/kWh or higher.

Table 38: Available Solar Energy Not Traded Due to No Demand, Existing Solar

<table>
<thead>
<tr>
<th>Total (kWh)</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>TOTAL</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Note this shows all solar energy available was traded, i.e. there is more capacity for solar to be sold. The analysis of the kilowatt hours available to be traded and consumption was done on a 30-minute interval basis across the year data set. In the existing solar generation scenario there is more demand than supply across all 30 minute trading intervals across the year.

Table 39: Baseline Data for the LVM94, Existing Solar

<table>
<thead>
<tr>
<th>LVM Financial baseline</th>
<th>Total</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed Tariff ($/year)</td>
<td>$45,049.00</td>
<td>$15,410.00</td>
<td>$27,613.00</td>
<td>$2,026.00</td>
</tr>
<tr>
<td>Usage Tariff ($/year)</td>
<td>$640,068.63</td>
<td>$58,050.77</td>
<td>$549,454.58</td>
<td>$32,563.28</td>
</tr>
<tr>
<td>Solar PV Export Revenue ($/year)</td>
<td>($21,289.36)</td>
<td>($9,867.31)</td>
<td>($10,909.78)</td>
<td>($512.27)</td>
</tr>
<tr>
<td>Solar PV Grid Offset Value ($/year)</td>
<td>$1,723.75</td>
<td>$587.50</td>
<td>$870.01</td>
<td>$266.25</td>
</tr>
</tbody>
</table>

Notes for Table 39 and Table 44:

- Fixed Tariff ($/year): This shows the total annual value of the fixed portion of energy bills across the LVMx94
- Usage Tariff ($/year): This shows the total annual usage ($/kWh component) of energy bills across the LVMx94
- Solar PV Export Revenue ($/year): This shows the total annual revenue generated for solar PV export from LVMx94 in to the grid at their actual FiT, or for proposed solar PV at the standard chosen FiT
- Solar PV Grid Offset Value ($/year): This shows the total annual behind the meter value of the solar PV for the LVMx94. If solar PV was not installed, this amount would be added to the usage tariff total.

The baseline data in Table 39 is used in the comparison with the scenario where a local energy marketplace has been implemented. This allows the relative ‘winners and losers’ to be calculated.
PROPOSED SOLAR

The proposed solar setting was modelled to look at the dynamics of the marketplace when there were more solar exports available for trading. The proposed solar generation includes all of the 94 participant NMIs, and any existing solar PV system installed, but also included the augmentation of solar PV generation throughout the LVM, assuming that those feasibility study participants who requested desktop solar proposals had those systems installed. This meant another 25 solar PV systems were added (to give a total of 55 systems within the group), with a peak generation capacity of around 182kW added.

Table 40: Total Exported Solar (kWh), Proposed Solar

<table>
<thead>
<tr>
<th></th>
<th>Total (kWh)</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>182450.3</td>
<td>46056.3</td>
<td>132812.1</td>
<td>3581.8</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>72693.4</td>
<td>17490.1</td>
<td>53759.4</td>
<td>1443.8</td>
</tr>
<tr>
<td>TOTAL</td>
<td>255143.6</td>
<td>63546.5</td>
<td>186571.6</td>
<td>5025.6</td>
</tr>
</tbody>
</table>

Table 40 above shows the breakdown of total exported solar (noting that some of the solar within this set is not physically installed, but has had a solar proposal developed specifically for that site and consumption profile) by period. As would be expected, the bulk of the exports are during peak periods, with almost three-quarters of exports coming from dairy farms within the participant group, and almost all the remainder from residential participants.

Table 41: Available Solar Energy for Trading on the Local Energy Marketplace, Proposed Solar

<table>
<thead>
<tr>
<th></th>
<th>Total (kWh)</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>152070.4</td>
<td>35264.5</td>
<td>113363</td>
<td>3442.9</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>62874.4</td>
<td>13729</td>
<td>47728.9</td>
<td>1416.5</td>
</tr>
<tr>
<td>TOTAL</td>
<td>214944.8</td>
<td>48993.5</td>
<td>161091.9</td>
<td>4859.4</td>
</tr>
</tbody>
</table>

Table 41 shows the volume of exported solar energy that is available to be traded on the local energy marketplace. Solar energy is only made available for trading where it is economically beneficial for that to take place. This volume therefore excludes any exports that currently enjoy high feed-in-tariffs, which is shown in Table 42 below.

Table 42: Solar Energy Not Available for Trading Due to High Feed-in-Tariff, Proposed Solar

<table>
<thead>
<tr>
<th></th>
<th>Total (kWh)</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>24075.4</td>
<td>9433</td>
<td>14642.4</td>
<td>0</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>8719.7</td>
<td>3547.5</td>
<td>5172.3</td>
<td>0</td>
</tr>
<tr>
<td>TOTAL</td>
<td>32795.2</td>
<td>12980.5</td>
<td>19814.7</td>
<td>0</td>
</tr>
</tbody>
</table>
The total volume of kilowatt hours that are not traded due to a high feed-in-tariff is 12.9% of the total volume of exported kilowatt hours. There are 11 systems that receive FiTs of 20 c/kWh and above, with most (9 out of 11) receiving a FiT of 60c/kWh or higher.

Table 43: Available Solar Energy Not Traded Due to No Demand, Proposed Solar

<table>
<thead>
<tr>
<th></th>
<th>Total (kWh)</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>6304.4</td>
<td>1358.9</td>
<td>4806.7</td>
<td>76.20%</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>1099.3</td>
<td>213.6</td>
<td>858.3</td>
<td>78.10%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>7403.7</td>
<td>1572.5</td>
<td>5665</td>
<td>76.50%</td>
</tr>
</tbody>
</table>

The analysis of the kilowatt hours available to be traded and consumption was done on a 30-minute interval basis across the year data set. During some of those periods where there are kilowatt hours available to be traded there is insufficient demand, which means there are no buyers for the available solar energy. This is a relatively small proportion of the total available solar energy however, at 2.9%.

Table 44: Baseline Data for the LVM94, Proposed Solar

<table>
<thead>
<tr>
<th>LVM Financial baseline</th>
<th>Total</th>
<th>RESIDENTIAL</th>
<th>FARM</th>
<th>COMMERCIAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed Tariff ($/year)</td>
<td>$45,049.00</td>
<td>$15,410.00</td>
<td>34.20%</td>
<td>$27,613.00</td>
</tr>
<tr>
<td>Usage Tariff ($/year)</td>
<td>$604,739.71</td>
<td>$55,888.15</td>
<td>9.20%</td>
<td>$516,330.86</td>
</tr>
<tr>
<td>Solar PV Export Revenue ($/year)</td>
<td>($43,332.54)</td>
<td>($13,313.14)</td>
<td>30.70%</td>
<td>($29,451.51)</td>
</tr>
<tr>
<td>Solar PV Grid Offset Value ($/year)</td>
<td>$37,051.62</td>
<td>$2,750.12</td>
<td>7.40%</td>
<td>$33,992.69</td>
</tr>
</tbody>
</table>

Notes for

Table 39 and Table 44:

- Fixed Tariff ($/year): This shows the total annual value of the fixed portion of energy bills across the LVMx94
- Usage Tariff ($/year): This shows the total annual usage ($/kWh component) of energy bills across the LVMx94
- Solar PV Export Revenue ($/year): This shows the total annual revenue generated for solar PV export from LVMx94 in to the grid at their actual FiT, or for proposed solar PV at the standard chosen FiT
- Solar PV Grid Offset Value ($/year): This shows the total annual behind the meter value of the solar PV for the LVMx94. If solar PV was not installed, this amount would be added to the usage tariff total.

The baseline data in Table 44 is used in the comparison with the scenario where a local energy marketplace has been implemented. This allows the relative ‘winners and losers’ to be calculated.
As discussed in section 5.2.2, there were two levels of solar generation modelled in the feasibility analysis, one without the 25 solar proposals and the other with the 25 solar proposals. The latter was considered to be the most informative, and is therefore discussed in the main body of the report. The results for LEM transactions assuming only the current level of solar generation are set out in this appendix.

RESULTS OF SCENARIO 1 – EXISTING SOLAR ONLY

For Scenario 1 the following baseline parameters, for the counterfactual scenario, were applied, for comparison with the active marketplace alternative.

<table>
<thead>
<tr>
<th>Table 45: Scenario 1, Baseline Parameters, Existing Solar</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Baseline values for all energy</strong></td>
</tr>
<tr>
<td>All Total $</td>
</tr>
<tr>
<td>---------------</td>
</tr>
<tr>
<td>Total Tariffs Paid by active P2P buyers all energy consumed</td>
</tr>
<tr>
<td>Total FiT Revenue for Seller all energy exported (excluding high FiT)</td>
</tr>
<tr>
<td>Total Network and Market Costs incurred from active P2P buyers from all energy consumed</td>
</tr>
<tr>
<td>Total Retailers Portion from active P2P buyers all energy consumed</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Baseline values for energy traded within the P2P marketplace</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total $</td>
</tr>
<tr>
<td>---------------</td>
</tr>
<tr>
<td>Total Tariffs Paid by active P2P buyers during P2P trade window</td>
</tr>
<tr>
<td>Total FiT Revenue for Seller energy sold in to P2P market</td>
</tr>
<tr>
<td>Total Network and Market Costs incurred from energy in P2P trade window</td>
</tr>
<tr>
<td>Total Retailers Portion from active P2P buyers during P2P trade window</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 46: Scenario 1, Technical Baseline Parameters, Existing Solar</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Volume of Energy purchased by active P2P buyers all energy</strong></td>
</tr>
<tr>
<td>ALL Total kWh</td>
</tr>
<tr>
<td>----------------</td>
</tr>
<tr>
<td>Peak</td>
</tr>
<tr>
<td>Off-Peak</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Volume of Energy purchased by buyers within the P2P marketplace</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>ALL Total kWh</td>
</tr>
<tr>
<td>----------------</td>
</tr>
<tr>
<td>Peak</td>
</tr>
<tr>
<td>Off-Peak</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>
In this scenario there are 36 active buyers during the peak, 41 active buyers during the off-peak, and 57 buyers in total who are active local energy marketplace participants.

There are 53 remaining profitable buyers who could purchase an additional 654,572 kWh of energy from the marketplace during the peak, and 43 who could purchase 254,178 kWh during the off-peak i.e. there is latent demand within the marketplace, even with the expanded solar generation, which could be met by more solar/other DER assets.

There are 19 P2P energy sellers (PV exporters) within the marketplace, of which 12 are also buyers. Therefore, there are 64 active participants trading energy within the local energy marketplace in total.

The volume of energy purchased within the local energy marketplace is 10.7% of the total consumption of these 64 active participants, 16.9% of peak consumption, 5.4% of off-peak consumption, with approximately 90% of all traded kilowatt hours being bought by farmers.

Figure 18 below shows the relative economic value that accrues to different market actors under Scenario 1.

**Figure 18: Scenario 1 Economic Value of Local Energy Marketplace by Market Actor, Existing Solar**
### Table 47: Scenario 1 Results from the Perspective of a LEM Buyer, or Consumer, Existing Solar

<table>
<thead>
<tr>
<th>Counterfactual ($)</th>
<th>Cost of energy in the Local Energy Marketplace (LEM)</th>
<th>Change in value ($)</th>
<th>Change in value (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>22,369</td>
<td>Moderate clearing price 14,453</td>
<td>7,915</td>
<td>35.4</td>
</tr>
<tr>
<td></td>
<td>High clearing price 17,097</td>
<td>5,272</td>
<td>23.6</td>
</tr>
<tr>
<td></td>
<td>Low clearing price 11,810</td>
<td>10,559</td>
<td>47.2</td>
</tr>
</tbody>
</table>

### Table 48: Scenario 1 Results from the Perspective of a LEM Seller, or Prosumer, Existing Solar

<table>
<thead>
<tr>
<th>Counterfactual ($)</th>
<th>Revenue for selling energy in the LEM</th>
<th>Change in Value ($)</th>
<th>Change in value (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>6,538</td>
<td>Moderate clearing price 14,453</td>
<td>7,915</td>
<td>121.1</td>
</tr>
<tr>
<td></td>
<td>High clearing price 17,097</td>
<td>10,559</td>
<td>161.5</td>
</tr>
<tr>
<td></td>
<td>Low clearing price 11,809</td>
<td>5,272</td>
<td>80.6</td>
</tr>
</tbody>
</table>

### Table 49: Scenario 1 Results from the Perspective of the LEM Retailer, Existing Solar

<table>
<thead>
<tr>
<th></th>
<th>Revenues ($)</th>
<th>Margin ($)</th>
<th>Loss</th>
</tr>
</thead>
<tbody>
<tr>
<td>Counterfactual</td>
<td>95,188</td>
<td>12,374</td>
<td>-1,641</td>
</tr>
<tr>
<td>LEM trading</td>
<td>82,559</td>
<td>10,733</td>
<td>-9,739</td>
</tr>
<tr>
<td>Loss in margin ($)</td>
<td></td>
<td></td>
<td>-11,381</td>
</tr>
<tr>
<td>Additional cost for retailer, network charges ($)</td>
<td></td>
<td></td>
<td>-9,739</td>
</tr>
<tr>
<td>Change in value ($)</td>
<td></td>
<td></td>
<td>-11,381</td>
</tr>
<tr>
<td>Change in value (%)</td>
<td></td>
<td></td>
<td>-12.00%</td>
</tr>
</tbody>
</table>
RESULTS OF SCENARIO 2 – EXISTING SOLAR ONLY

For Scenario 2, taking into account the existing solar only, the following baseline parameters, for the counterfactual scenario, were applied, for comparison with the active marketplace alternative.

Table 50: Scenario 2, Baseline Parameters, Existing Solar

<table>
<thead>
<tr>
<th>Baseline values for all energy</th>
<th>ALL Total $</th>
<th>RESIDENTIAL Total $</th>
<th>FARM Total $</th>
<th>COMMERCIAL Total $</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Tariffs Paid by active P2P buyers all energy consumed</td>
<td>173,134.10</td>
<td>16,124.60</td>
<td>156,233.00</td>
<td>776.5</td>
</tr>
<tr>
<td>Total FiT Revenue for Seller all energy exported (excluding high FiT)</td>
<td>6,537.90</td>
<td>4,293.90</td>
<td>1,745.30</td>
<td>498.7</td>
</tr>
<tr>
<td>Total Network and Market Costs incurred from active P2P buyers from all energy consumed</td>
<td>70,215.80</td>
<td>7,934.60</td>
<td>61,972.50</td>
<td>308.6</td>
</tr>
<tr>
<td>Total Retailers Portion from active P2P buyers all energy consumed</td>
<td>102,918.30</td>
<td>8,190.00</td>
<td>94,260.50</td>
<td>467.9</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Baseline values for energy traded within the P2P marketplace</th>
<th>ALL Total $</th>
<th>RESIDENTIAL Total $</th>
<th>FARM Total $</th>
<th>COMMERCIAL Total $</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Tariffs Paid by active P2P buyers during P2P trade window</td>
<td>22,205.90</td>
<td>1,317.80</td>
<td>20,787.20</td>
<td>101</td>
</tr>
<tr>
<td>Total FiT Revenue for Seller energy sold in to P2P market</td>
<td>6,537.90</td>
<td>4,293.90</td>
<td>1,745.30</td>
<td>498.7</td>
</tr>
<tr>
<td>Total Network and Market Costs incurred from energy in P2P trade window</td>
<td>9,398.10</td>
<td>664.4</td>
<td>8,703.00</td>
<td>30.7</td>
</tr>
<tr>
<td>Total Retailers Portion from active P2P buyers during P2P trade window</td>
<td>12,807.80</td>
<td>653.4</td>
<td>12,084.20</td>
<td>70.2</td>
</tr>
</tbody>
</table>

Table 51: Scenario 2, Technical Baseline Parameters, Existing Solar

<table>
<thead>
<tr>
<th>Volume of Energy purchased by active P2P buyers all energy</th>
<th>ALL Total kWh</th>
<th>% of Total</th>
<th>RESIDENTIAL Total kWh</th>
<th>% of Total</th>
<th>FARM Total kWh</th>
<th>% of Total</th>
<th>COMMERCIAL Total kWh</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>231,779.70</td>
<td>38.00%</td>
<td>32,524.50</td>
<td>14.00%</td>
<td>198,120.30</td>
<td>85.50%</td>
<td>1,134.90</td>
<td>0.50%</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>377,875.50</td>
<td>62.00%</td>
<td>22,466.90</td>
<td>5.90%</td>
<td>354,126.90</td>
<td>93.70%</td>
<td>1,281.70</td>
<td>0.30%</td>
</tr>
<tr>
<td>Total</td>
<td>609,655.10</td>
<td>100.00%</td>
<td>54,991.30</td>
<td>9.00%</td>
<td>552,247.10</td>
<td>90.60%</td>
<td>2,416.70</td>
<td>0.40%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Volume of Energy purchased by buyers within the P2P marketplace</th>
<th>ALL Total kWh</th>
<th>% of Total</th>
<th>RESIDENTIAL Total kWh</th>
<th>% of Total</th>
<th>FARM Total kWh</th>
<th>% of Total</th>
<th>COMMERCIAL Total kWh</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>43,612.10</td>
<td>73.40%</td>
<td>2,895.70</td>
<td>6.60%</td>
<td>40,641.50</td>
<td>93.20%</td>
<td>74.9</td>
<td>0.20%</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>15,823.00</td>
<td>26.60%</td>
<td>1,221.20</td>
<td>7.70%</td>
<td>14,862.50</td>
<td>90.80%</td>
<td>239.3</td>
<td>1.50%</td>
</tr>
<tr>
<td>Total</td>
<td>59,435.10</td>
<td>100.00%</td>
<td>4,116.90</td>
<td>6.90%</td>
<td>55,004.00</td>
<td>92.50%</td>
<td>314.2</td>
<td>0.50%</td>
</tr>
</tbody>
</table>
In this scenario there are 38 active buyers during the peak period, 32 active buyers during the off-peak period, and 44 buyers in total who are active P2P participants.

There are 53 remaining profitable buyers who could purchase an additional 654,572 kWh of energy from the local energy marketplace during the peak period, and 43 who could purchase an additional 254,178 kWh during the off-peak period.

There are 19 active energy sellers (PV exporters) within the marketplace, of which 13 are also buyers.

Therefore, there are 50 active participants trading energy within the local energy marketplace.

The volume of energy purchased within the local energy marketplace is 9.7% of the total consumption of these 50 active participants, 18.8% of peak consumption, 4.2% of off-peak consumption, with more than ninety percent of all consumption being bought by farmers.

Figure 19 below shows the relative economic value that accrues to different market actors under Scenario 2.

**Figure 19: Scenario 2 Economic Value of Local Energy Marketplace by Market Actor, Existing Solar**
### Table 52: Scenario 2 Results from the Perspective of a LEM Buyer, or Consumer, Existing Solar

<table>
<thead>
<tr>
<th>Counterfactual ($)</th>
<th>Cost of energy in the Local Energy Marketplace (LEM)</th>
<th>Change in value ($)</th>
<th>Change in value (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>22,206</td>
<td>Moderate clearing price 16,721</td>
<td>5,485</td>
<td>24.7</td>
</tr>
<tr>
<td></td>
<td>High clearing price 18,553</td>
<td>3,652</td>
<td>16.4</td>
</tr>
<tr>
<td></td>
<td>Low clearing price 14,890</td>
<td>7,316</td>
<td>32.9</td>
</tr>
</tbody>
</table>

### Table 53: Scenario 2 Results from the Perspective of a LEM Seller, or Prosumer, Existing Solar

<table>
<thead>
<tr>
<th>Counterfactual ($)</th>
<th>Revenue for selling energy in the LEM</th>
<th>Change in Value ($)</th>
<th>Change in value (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>6,538</td>
<td>Moderate clearing price 7,323</td>
<td>785</td>
<td>8.4</td>
</tr>
<tr>
<td></td>
<td>High clearing price 9,155</td>
<td>2,617</td>
<td>27.8</td>
</tr>
<tr>
<td></td>
<td>Low clearing price 5,492</td>
<td>-1,046</td>
<td>-11.1</td>
</tr>
</tbody>
</table>

### Table 54: Scenario 2 Results from the Perspective of the LEM Retailer, Existing Solar

<table>
<thead>
<tr>
<th></th>
<th>Revenues ($)</th>
<th>Margin ($)</th>
<th>Loss</th>
</tr>
</thead>
<tbody>
<tr>
<td>Counterfactual</td>
<td>102,918</td>
<td>13,379</td>
<td></td>
</tr>
<tr>
<td>LEM trading</td>
<td>90,111</td>
<td>11,714</td>
<td></td>
</tr>
<tr>
<td>Loss in margin ($)</td>
<td></td>
<td></td>
<td>-1,665</td>
</tr>
<tr>
<td>Additional cost for retailer, network charges ($)</td>
<td></td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>Change in value ($)</td>
<td></td>
<td></td>
<td>-1,665</td>
</tr>
<tr>
<td>Change in value (%)</td>
<td></td>
<td></td>
<td>-1.60%</td>
</tr>
</tbody>
</table>
RESULTS OF SCENARIO 3 – EXISTING SOLAR ONLY

For Scenario 3, taking into account the existing solar only, the following baseline parameters, for the counterfactual scenario, were applied, for comparison with the active marketplace alternative.

Table 55: Scenario 3, Baseline Parameters, Existing Solar

<table>
<thead>
<tr>
<th>Baseline values for all energy</th>
<th>ALL Total $</th>
<th>RESIDENTIAL Total $</th>
<th>FARM Total $</th>
<th>COMMERCIAL Total $</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Tariffs Paid by active P2P buyers all energy consumed</td>
<td>164,346.70</td>
<td>16,124.60</td>
<td>147,445.60</td>
<td>776.5</td>
</tr>
<tr>
<td>Total FiT Revenue for Seller all energy exported (excluding high FiT)</td>
<td>6,537.90</td>
<td>4,293.90</td>
<td>1,745.30</td>
<td>498.7</td>
</tr>
<tr>
<td>Total Network and Market Costs incurred from active P2P buyers from all energy consumed</td>
<td>66,872.70</td>
<td>7,934.60</td>
<td>58,629.50</td>
<td>308.6</td>
</tr>
<tr>
<td>Total Retailers Portion from active P2P buyers all energy consumed</td>
<td>97,473.90</td>
<td>8,190.00</td>
<td>88,816.10</td>
<td>467.9</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Baseline values for energy traded within the P2P marketplace</th>
<th>ALL Total $</th>
<th>RESIDENTIAL Total $</th>
<th>FARM Total $</th>
<th>COMMERCIAL total $</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Tariffs Paid by active P2P buyers during P2P trade window</td>
<td>22,181.40</td>
<td>1,317.80</td>
<td>20,762.70</td>
<td>101</td>
</tr>
<tr>
<td>Total FiT Revenue for Seller energy sold in to P2P market</td>
<td>6,522.50</td>
<td>4,283.50</td>
<td>1,741.50</td>
<td>497.4</td>
</tr>
<tr>
<td>Total Network and Market Costs incurred from energy in P2P trade window</td>
<td>9,388.80</td>
<td>664.4</td>
<td>8,693.70</td>
<td>30.7</td>
</tr>
<tr>
<td>Total Retailers Portion from active P2P buyers during P2P trade window</td>
<td>12,792.60</td>
<td>653.4</td>
<td>12,069.00</td>
<td>70.2</td>
</tr>
</tbody>
</table>

Table 56: Scenario 2, Technical Baseline Parameters, Existing Solar

<table>
<thead>
<tr>
<th>Volume of Energy purchased by active P2P buyers all energy</th>
<th>ALL Total kWh</th>
<th>% of Total</th>
<th>RESIDENTIAL Total kWh</th>
<th>% of Total</th>
<th>FARM Total kWh</th>
<th>% of Total</th>
<th>COMMERCIAL Total kWh</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>23179.7</td>
<td>41.40%</td>
<td>12524.5</td>
<td>34.00%</td>
<td>198120.3</td>
<td>85.50%</td>
<td>1134.9</td>
<td>0.50%</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>327918.6</td>
<td>58.60%</td>
<td>22666.9</td>
<td>6.90%</td>
<td>300470</td>
<td>92.80%</td>
<td>1281.7</td>
<td>0.40%</td>
</tr>
<tr>
<td>Total</td>
<td>559698.3</td>
<td>100.00%</td>
<td>54991.3</td>
<td>9.80%</td>
<td>502290.3</td>
<td>89.70%</td>
<td>2416.7</td>
<td>0.40%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Volume of Energy purchased by buyers within the P2P marketplace</th>
<th>ALL Total kWh</th>
<th>% of Total</th>
<th>RESIDENTIAL Total kWh</th>
<th>% of Total</th>
<th>FARM Total kWh</th>
<th>% of Total</th>
<th>COMMERCIAL Total kWh</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>43612.1</td>
<td>73.60%</td>
<td>2895.7</td>
<td>6.60%</td>
<td>40641.5</td>
<td>93.20%</td>
<td>74.9</td>
<td>0.20%</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>15683.4</td>
<td>26.40%</td>
<td>1221.2</td>
<td>7.80%</td>
<td>14222.9</td>
<td>90.70%</td>
<td>239.3</td>
<td>1.50%</td>
</tr>
<tr>
<td>Total</td>
<td>59295.5</td>
<td>100.00%</td>
<td>4116.9</td>
<td>6.90%</td>
<td>54864.4</td>
<td>92.50%</td>
<td>314.2</td>
<td>0.50%</td>
</tr>
</tbody>
</table>

In this scenario there are 38 active buyers during the peak periods, 31 active buyers during the off-peak periods, and 44 buyers in total who are active P2P participants.
There are 7 remaining profitable buyers who could purchase an additional 82,557 kWh of energy from the marketplace during the peak. There are no more buyers who could purchase profitably during the off-peak period.

There are 19 active energy sellers (PV exporters) within the marketplace, of which 13 are also buyers.

Therefore, there are 50 active participants trading energy within the local energy marketplace.

The volume of energy purchased within the local energy marketplace is 10.6% of the total consumption of these 50 active participants, 18.8% of peak consumption, 4.8% of off-peak consumption, with more than ninety percent of all consumption being bought by farmers.

Figure 20 below shows the relative economic value that accrues to different market actors under Scenario 3.

**Figure 20: Scenario 3 Economic Value of Local Energy Marketplace by Market Actor, Existing Solar**
Table 57: Scenario 3 Results from the Perspective of a LEM Buyer, or Consumer, Existing Solar

<table>
<thead>
<tr>
<th>Counterfactual ($)</th>
<th>Cost of energy in the Local Energy Marketplace (LEM)</th>
<th>Change in value ($)</th>
<th>Change in value (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>22,181</td>
<td>Moderate clearing price 19,046</td>
<td>3,135</td>
<td>14.1</td>
</tr>
<tr>
<td></td>
<td>High clearing price 20,093</td>
<td>2,088</td>
<td>9.4</td>
</tr>
<tr>
<td></td>
<td>Low clearing price 17,999</td>
<td>4,182</td>
<td>18.9</td>
</tr>
</tbody>
</table>

Table 58: Scenario 3 Results from the Perspective of a LEM Seller, or Prosumer, Existing Solar

<table>
<thead>
<tr>
<th>Counterfactual ($)</th>
<th>Revenue for selling energy in the LEM</th>
<th>Change in Value ($)</th>
<th>Change in value (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>6,538</td>
<td>Moderate clearing price 9,658</td>
<td>3,135</td>
<td>48.1</td>
</tr>
<tr>
<td></td>
<td>High clearing price 10,705</td>
<td>4,182</td>
<td>64.1</td>
</tr>
<tr>
<td></td>
<td>Low clearing price 8,610</td>
<td>2,088</td>
<td>32</td>
</tr>
</tbody>
</table>

Table 59: Scenario 3 Results from the Perspective of the LEM Retailer, Existing Solar

<table>
<thead>
<tr>
<th></th>
<th>Revenues ($)</th>
<th>Margin ($)</th>
<th>Loss</th>
</tr>
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<tbody>
<tr>
<td>Counterfactual</td>
<td>97,474</td>
<td>12,672</td>
<td></td>
</tr>
<tr>
<td>LEM trading</td>
<td>84,681</td>
<td>11,008</td>
<td>-1,663</td>
</tr>
<tr>
<td>Loss in margin ($)</td>
<td></td>
<td></td>
<td>-1,663</td>
</tr>
<tr>
<td>Additional cost for retailer, network charges ($)</td>
<td></td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>Change in value ($)</td>
<td></td>
<td></td>
<td>-1,663</td>
</tr>
<tr>
<td>Change in value (%)</td>
<td></td>
<td></td>
<td>-1.70%</td>
</tr>
</tbody>
</table>
### Table 60: Detailed Tariff Data for Full Set of LVM124

<table>
<thead>
<tr>
<th>REF</th>
<th>Peak Usage Rate ($/kWh)</th>
<th>Off-Peak Usage Rate ($/kWh)</th>
<th>Fixed Rate ($/year)</th>
<th>Peak Usage Rate ($/kWh)</th>
<th>Off-Peak Usage Rate ($/kWh)</th>
<th>Fixed Rate ($/year)</th>
<th>Market Charges w. MLF applied</th>
<th>Peak Usage Rate ($/kWh)</th>
<th>Off-Peak Usage Rate ($/kWh)</th>
<th>Fixed Rate ($/year)</th>
<th>Participant Segment</th>
</tr>
</thead>
<tbody>
<tr>
<td>LVM001</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.175134</td>
<td>0.036346</td>
<td>120</td>
<td>0.028514258</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>RESIDENTIAL</td>
</tr>
<tr>
<td>LVM002</td>
<td>0.291524</td>
<td>0.164796</td>
<td>412.415</td>
<td>0.175134</td>
<td>0.036346</td>
<td>120</td>
<td>0.028514258</td>
<td>0.087596742</td>
<td>0.099935742</td>
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<td>RESIDENTIAL</td>
</tr>
<tr>
<td>LVM003</td>
<td>0.270392</td>
<td>0.14527</td>
<td>456.25</td>
<td>0.175122</td>
<td>0.036345</td>
<td>109</td>
<td>0.028514258</td>
<td>0.066465742</td>
<td>0.080410742</td>
<td>347.25</td>
<td>RESIDENTIAL</td>
</tr>
<tr>
<td>LVM004</td>
<td>0.279</td>
<td>0.12492</td>
<td>474.5</td>
<td>0.167825</td>
<td>0.038404</td>
<td>109</td>
<td>0.028514258</td>
<td>0.082660742</td>
<td>0.058001742</td>
<td>365.5</td>
<td>FARM</td>
</tr>
<tr>
<td>LVM005</td>
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<td>0</td>
<td>0</td>
<td>0.096213</td>
<td>0.096213</td>
<td>109</td>
<td>0.028514258</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>FARM</td>
</tr>
<tr>
<td>LVM006</td>
<td>0.279</td>
<td>0.12492</td>
<td>474.5</td>
<td>0.161614</td>
<td>0.038404</td>
<td>109</td>
<td>0.028514258</td>
<td>0.088871742</td>
<td>0.058001742</td>
<td>365.5</td>
<td>FARM</td>
</tr>
<tr>
<td>LVM007</td>
<td>0.279</td>
<td>0.12492</td>
<td>474.5</td>
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<td>0.038404</td>
<td>109</td>
<td>0.028514258</td>
<td>0.088871742</td>
<td>0.058001742</td>
<td>365.5</td>
<td>FARM</td>
</tr>
<tr>
<td>LVM008</td>
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<td>0.2268</td>
<td>474.5</td>
<td>0.13199</td>
<td>0.13199</td>
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<td>0.028514258</td>
<td>0.066295742</td>
<td>0.066295742</td>
<td>365.5</td>
<td>FARM</td>
</tr>
<tr>
<td>LVM009</td>
<td>0.279</td>
<td>0.12492</td>
<td>474.5</td>
<td>0.167825</td>
<td>0.038404</td>
<td>109</td>
<td>0.028514258</td>
<td>0.082660742</td>
<td>0.058001742</td>
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<td>FARM</td>
</tr>
<tr>
<td>LVM010</td>
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<td>438.5</td>
<td>FARM</td>
</tr>
<tr>
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<td>547.5</td>
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<td>109</td>
<td>0.028514258</td>
<td>0.069182742</td>
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<tr>
<td>LVM013</td>
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<td>109</td>
<td>0.028514258</td>
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<td>438.5</td>
<td>FARM</td>
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<tr>
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<td>0.028514258</td>
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<td>0.068156742</td>
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<td>FARM</td>
</tr>
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<td>LVM017</td>
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<tr>
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<tr>
<td>REF</td>
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<td>Off-Peak Usage Rate ($/kWh)</td>
<td>Fixed Rate ($/year)</td>
<td>Peak Usage Rate ($/kWh)</td>
<td>Off-Peak Usage Rate ($/kWh)</td>
<td>Fixed Rate ($/year)</td>
<td>Market Charges w. MLF applied ($/kWh)</td>
<td>Peak Usage Rate ($/kWh)</td>
<td>Off-Peak Usage Rate ($/kWh)</td>
<td>Fixed Rate ($/year)</td>
<td>Participant Segment</td>
</tr>
<tr>
<td>-------</td>
<td>------------------------</td>
<td>----------------------------</td>
<td>---------------------</td>
<td>------------------------</td>
<td>----------------------------</td>
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</tr>
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Latrobe Valley Microgrid Feasibility Study
Legal and regulatory recommendations and analysis
Prepared for LO3 Energy Pty Ltd
May 2019
Introduction

Residential energy consumers have traditionally been provided with 2 key services by the National Energy Market (NEM):

- stable energy prices: retailers protect the consumer from the volatility and complexity of the wholesale market by providing energy at stable prices
- stable network charges: networks supplying energy to consumers in a stable and reliable manner

However, the role of the energy consumer is evolving (and some might say this process has only just begun). Energy consumers now consume electricity they generate themselves, and electricity from the grid. They also actively engage with the NEM, providing excess generation, demand response and ancillary services (Active Consumers).

In contrast to traditional energy consumers, Active Consumers expect to be able to:

- sell excess generation: sell their excess generation, pooled through local or independent aggregators, to enable them to benefit financially from their solar units
- sell demand response: engage in demand management utilising automated and controllable systems to optimise their consumption and their energy costs
- sell ancillary services: provide market ancillary services, pooled through local or independent aggregators, to enable them to benefit financially from their solar units
- sell to and buy from their neighbours: sell to and buy from their neighbours through local or independent market operators, separately from the wholesale market

(together, New Energy Services).

These services are not merely an extension of the current network and retail services – in many respects they are disruptive to the very business models of current network and retail service providers. To illustrate, traditional retailers sell electricity from the wholesale market to consumers, deriving profits from increased consumption, whereas demand management has the effect of decreasing consumption from the grid. Alternative service providers (New Energy Service Providers) have now entered the market with new offerings and business models to support and encourage the provision of these New Energy Services.

In response, regulators around the world, including the Australian Energy Market Commission (AEMC), are actively considering and implementing mechanisms that foster, enable and encourage New Energy Service Providers.\(^1\) This report provides a number of recommendations in support of that long-term aim. We note that the AEMC is in the process of putting a “regulatory sandbox” mechanism in place. This mechanism may be a suitable environment in which to further test and explore these recommendations.\(^2\)

Purpose and nature of this report

This report is written from the perspective of New Energy Service Providers.

We have been asked to consider the obstacles and challenges posed by the current regulatory and legal frameworks in Australia to the adoption, rise and success of New Energy Services, and make recommendations within that context. Our recommendations do not consider or have regard to the economic or other commercial costs or impacts they may have on other industry stakeholders. This is beyond the scope of this report.

Recommendations

To facilitate the role of New Energy Service Providers, we recommend consideration be given to further regulatory change in the following areas:

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\(^1\) See Section 7 of “More Details” for an extensive list of Australian reports, reviews and programs that have focused on this topic.

Retail market: encourage new market participants with innovative business models in the retail market:

- **Recommendation #1**: Establish a new Market Participant classification for New Energy Service Providers. This will allow New Energy Service Providers to supply demand management, sell aggregated generation to the grid and facilitate peer-to-peer trading

  This recommendation is consistent with the AEMC’s recommendations in the [Reliability Frameworks Review](#), which recognises the need to define the role of New Energy Service Providers.

  We also recommend that the rules be extended beyond the recent rule changes that established “Market Small Generation Aggregator” and “Market Ancillary Service Providers” so as to give the Australian Energy Market Operator (AEMO) flexibility and optionality in categorising new Market Participants, to enable the categories to keep pace with the changing nature of New Energy Service Providers.

- **Recommendation #2**: Allow consumers to contract with multiple service providers at the same connection point

  This recommendation, to allow multiple trading relationships at the same connection point, is also consistent with the AEMC’s recommendations in the [Reliability Frameworks Review](#). We also endorse the AEMC’s suggestion that methods should be developed for sharing financial responsibility and customer protections amongst all service providers at a single connection point.

Energy market design: allow consumers to trade energy, demand response and ancillary services in the wholesale market:

- **Recommendation #3**: Demand response mechanism established to allow New Energy Service Providers to bid demand response into the wholesale electricity market

  Endorsing the recent [demand response rule changes](#), we recommend that a demand management mechanism be established and that demand response aggregators be treated on equal footing to generators. We also recommend further consideration be given to potential options that would enable greater use of non-firm demand response.

- **Recommendation #4**: Increase engagement and access to ancillary support markets

  We endorse the AEMC’s recommendation in the [Frequency Control Framework Review](#) that the existing rules relating to Market Ancillary Service Providers and Small Generation Aggregators be amended so as to allow New Energy Service Providers equal access to the FCAS market.

Distribution System and Market Operators: manage markets and physical assets to ensure supply and demand are balanced:

- **Recommendation #5**: Establish and provide support for Distribution System and Market Operators (DSMOs) to oversee mechanisms for control and trading of New Energy Services, including demand response, aggregated generation and peer-to-peer

  We recommend that independent Distribution System and Market Operators be established to provide support for and co-ordination of the services to be provided by New Energy Service Providers.

- **Recommendation #6**: Facilitate data access and sharing between Market Participants, while maintaining privacy and confidentiality protections

  In addition to establishing independent Distribution System and Market Operators, current energy data requirements should be updated to reflect the changing nature of the energy market and distribution system. We recommend that a data sharing framework be implemented and managed by AEMO, supported by independent Distribution System and Market Operators.

- **Recommendation #7**: Mandate cooperation between traditional Market Participants and New Energy Service Providers and establish appropriate dispute resolution mechanisms, including establishing rules and procedures for financial licencing, billing, data exchange and security
As the distribution network and associated markets become more complex, co-operation between market participants (particularly those at the same connection point) will become increasingly necessary. We recommend that consideration be given to Distribution System and Market Operators being charged with the role of not only managing co-operation but also overseeing potential disputes between market participants.

**Distribution Network**: ensure that the network (and its pricing model) caters to and facilitates bi-directional energy flows:

- **Recommendation #8**: Enhance and maintain the visibility of and the data available on the component parts of the distribution network
  
  Increasing data sharing among Market Participants is beneficial (as set out in recommendation #7) however the availability of adequate distribution network data is also required to ensure all Market Participants are able to assess the true cost and value of electricity services. We recommend that distribution networks are incentivised to increase the collection of data to provide all market participants better visibility of the component parts of the distribution network. This will provide New Energy Service Providers information which will enable them to target their services so as to avoid or mitigate grid augmentation requirements and costs.

- **Recommendation #9**: Mandate opt-out cost-reflective pricing for networks and remove structural barriers for uptake of cost-reflective pricing
  
  The AEMC has already enacted significant rule changes to network pricing in this regard, however there has been limited take up to date of AEMC’s new model of network pricing. We recommend that cost-reflective pricing is opt-out (rather than opt-in as it is currently) and that the State legislation that creates structural barriers to the uptake of locational based pricing be removed or amended.

- **Recommendation #10**: Require networks to engage in good faith negotiations with New Energy Service Providers regarding network charging
  
  Cost-reflective pricing (as above) is a positive step forward for Active Consumers, however there are many other alternative pricing models that may provide better outcomes (particularly for those involved in peer-to-peer trading). We recommend that, similar to the negotiated connection regime in Chapter 5, distribution networks be required to negotiate with peer-to-peer service providers regarding network charging when benefits (such as grid augmentation avoidance) can be evidenced.

- **Recommendation #11**: Better integrate renewables by investing in and managing the grid so as to avoid zero export
  
  The EU has recently implemented a right for all consumers to connect and export electricity to the grid. We suggest that Chapter 5A be amended to ensure that networks are required to support solar connection and export (beyond requiring individual customers to pay for grid augmentation). We acknowledge, in saying this, that the costs of this will need to be carefully balanced against the benefits they will deliver to the consumer.
**Current state of play**

Under the National Energy Retail Law (NERL), the seller of electricity to a premises is required to be an authorised retailer or an exempt retailer. Further, under the National Energy Rules (NER), each connection point must be associated with one metering installation with its own National Meter Identifier (NMI) and one Financially Responsible Market Participant (FRMP).

The practical effect of this regulatory model is that all customers must have a retailer for supply from the market and if a consumer wishes to sell electricity to the grid, the consumer must in practice use the same entity they use to purchase electricity. That is, consumers must in practice sell electricity to the grid through *their* retailer. The only other alternative is to install a second connection point and to sell through a Small Generation Aggregator. This Small Generation Aggregator approach restricts the ability of New Energy Service Providers in the following ways:

- there must be two separate meters, one for the load and one for the generation (PV or battery storage)
- the meter that the SGA is responsible for must be export only
- the SGA is not able to provide ancillary services

If there is only one connection point and it will be used to import electricity (which will almost invariably be the case), New Energy Service Providers must have a retail licence, a retail licence exemption or partner with a retailer to utilise their retail licence (and an SGA will also require a retail licence (ie because electricity is also being imported through that connection point)). This is not without reason however, as retailers provide significant price protection for customers including, importantly, price stability.

See Section 1 of “More Details” for options available to New Energy Service Providers under the current regulatory model (including exemptions currently utilised by embedded networks) and why, in their current form, they are not conducive to the success of New Energy Service Providers.

**Recommendations**

**Recommendation #1**

Establish a new Market Participant classification for New Energy Service Providers. This will allow New Energy Service Providers to supply demand management, sell aggregated generation to the grid and facilitate peer-to-peer trading

Acknowledging that there is a distinct difference in the roles played by traditional energy Market Participants (eg retailers, networks and service providers and the market operator (ie AEMO)) and those played by New Energy Service Providers, leads to the logical conclusion that if New Energy Service Providers

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3 Section 88, National Energy Retail Law.
4 Section 2.3A.1, National Electricity Rules
Providers are to enter the market at scale, regulation will need to define the role and responsibilities of New Energy Service Providers as new Market Participants.

The AEMC has been proactive in creating alternative Market Participant regimes for New Energy Service Providers. Examples include:

- **Market Ancillary Service Provider**, introduced in November 2016. Market Ancillary Service Providers have the ability to provide FCAS Services through individual or an aggregation of market loads without the requirement to register as a Market Customer (ie an entity that purchases electricity from the spot market).

- **Small Generation Aggregator**, a registered participant which may supply electricity aggregated from one or more small generating units to a transmission or distribution system. Small Generation Aggregators must be Market Participants (not non-market) however can be semi-scheduled. Small Generation Aggregators must sell all sent out generation to the spot market and purchase (if required) all electricity supplied through the national grid to the market connection point.

- **Proposed Demand Response Service Provider**. According to AEMC this participant would be the only participant class able to sell demand response into the wholesale market through the demand response mechanism. Demand Response Service Providers would need to register with AEMO and also need to classify their loads as ‘demand response loads’. AEMC also goes further in supporting this new Market Participant by recommending that retailers would be prohibited from opting-out of it on behalf of their customers. That is, retailer participation in the demand response mechanism would be mandatory.

This recommendation aims to further progress the AEMC work in creating a separate classification for New Energy Service Providers by establishing a standardised new Market Participant classification. It is expected that this recommendation will go beyond the exemption framework (that is predominately used for embedded networks and set out in Section 1 of "More Details") and instead amend the rules to include a ‘gateway’ definition of new Market Participant. Further to this recommendation, we would also expect:

- that AEMO (in consultation with the AEMC) would be given flexibility and optionality in defining the conditions and classifications of each New Market Participant (registered under that classification) to enable the market classifications to keep pace with the changing nature of New Energy Service Providers

- that AEMO would be required to actively review new Market Participant registrations regularly to ensure all energy services are adequately and appropriately classified

- AEMO would establish guidelines that:
  - set out the appropriate licencing regime for New Energy Service Providers, acknowledging that a demand response provider will likely have different licencing requirements to a local energy market operator due to their different risk profiles
  - redefine the responsibilities for each party at a given connection point (ie who will be responsible for operation, bidding, network losses, settlement and prudential arrangements - see Recommendation #2 for more detail with respect to redefining the FRMP)
  - the existing rules to be updated to ensure/mandate:

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5 AEMC, *Demand Response Mechanism and Ancillary Services Unbundling* Rule Change (5 November 2015)

6 Section 2.3A.1(h), National Electricity Rules – note that if there are two connection points a Small Generation Aggregator may not be required to purchase electricity at the second connection point if a Retailer is supplying electricity at the other connection point. This is also the case for child meters in an embedded network.

7 AEMO, *SGA Factsheet*

- information sharing among all Market Participants, on a need-to-know basis (see section 3 below)
- that new Market Participants are registered without the need to be or to partner with traditional Market Participants (and as such are independent service providers)
- that consideration would be given to the suitability of generator classifications. For example it may be appropriate to amend the classification of non-scheduled generation so that both retailers and new Market Participants can register, however limits may also need to be imposed on:
  - the number of customers that a new Market Participant can have (ie aggregate nameplate of customers) within particular regions
  - the protections (in particular the disconnection protocols) that are to apply to the connection points that have multiple trading relationships (see Recommendation #2, discussion on limits to multiple trading relationships for more details)
- that the NERL be re-framed to include New Energy Service Providers (in addition to Retailers) while also updating the consumer protections and the roles and responsibilities that are currently set out in the NERL to reflect the new inclusion of New Energy Service Providers (as appropriate) (see Recommendation #2 for more details)

Recommendation #2:
Allow consumers to contract with multiple service providers at the same connection point

We support the AEMC recommendation in the Reliability Frameworks Review that a rule change be implemented to allow multiple trading relationships at the same connection point. This recommendation would give Active Consumers the right to contract (independently) with multiple service providers at the same connection point. Practically, this recommendation would mean that each connection point would be entitled to have multiple service providers, each with their own NMI, interacting with the wholesale market on their behalf.

The AEMC illustration sets out how multiple trading relationships could be implemented:

Figure A.2: Proposed arrangements
To implement multiple trading relationships, we endorse the AEMC’s recommendations in their Feasibility Review. The AEMC suggests the following key regulatory changes:

- **sharing of financial responsibility**: remove the requirement that there must only be one Financially Responsible Market Participant at a connection point. Instead, implement a new regime for the sharing of these responsibilities between all service providers (as appropriate).\(^9\)

- **settlement and billing**: consideration be given to updating settlement and billing regulation and procedures to accommodate multiple trading relationships.

The UK is considering a code change “P379: Enabling consumers to buy and sell electricity from/to multiple providers through Meter Splitting”.\(^10\) Unlike Australia, the UK already allows for dual metering under the SVA Shared Metering Arrangement, whereby co-owners of generation assets at large non-domestic sites can split export volumes by bilateral agreement. This proposal aims to extend meter splitting to multiple independent trading parties at domestic sites to facilitate new energy services.\(^11\)

The proposal suggests the following:

- customers would be able to engage multiple (not just two) trading partners at one meter and split the volumes between the trading partners

- the customers would have a ‘main’ or ‘default’ supplier (similar to the concept of retailer of last resort in the NER) responsible for metering and data collection/aggregation

- the customer would also have a new Party Agency called the Customer Notification Agent (CNA) that is responsible for reconciling flows through a Settlement Meter and notifying adjustments to metered volumes to reflect volumes attributed to additional Suppliers\(^12\)

As there would no longer be a bilateral agreement between the trading parties under this new proposal, roles and responsibilities (including in relation to connection and disconnection) would require a greater level of independent oversight and coordination.

The UK model is still in a consultation phase. Key issues being work-shopped include:

- how the roles and responsibilities of the ‘Supplier’ will be split between multiple parties

- how the disputes process will accommodate multiple trading parties

- who would step-in to take on the new responsibilities of CNAs- it has been suggested the DCC and Data Controller roles may be extended\(^13\)

We recommend that Australia continues to follow the developments in the UK while recognising the different nature of the Australian energy market.

- **alternative metering and settlement**: allow for alternative metering arrangements, such as subtractive metering. The AEMC notes that it is important that the rules do not ‘bake in’ a particular metering arrangement but instead allow for optionality and flexibility as new metering arrangements will no doubt arise after the adoption of multiple trading relationships. This recommendation would also require a change to the current metering coordination rules so as to require exchange of information between relevant parties.

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\(^10\) P379 “Multiple Suppliers through Meter Splitting”, (8 February 2019) Elexon website

\(^11\) Note that Elexon (the change proponent) sees P379 as a tactical change that can be delivered in shorter timeframes than the more extensive changes that are expected to arise out of the Ofgem *Future Supply Market Arrangements* review. The learnings of this change could then be used to inform the tactical changes of the Ofgem project. See *Elexon Webinar*, 12 minutes

\(^12\) Cornwall Insights P379 Workgroup presentation slides, slide 12

\(^13\) Elexon *P379 Meeting 1 Summary*, page 3
One possible alternative metering arrangement could be blockchain based sub-metering. Developed by a Netherland metering operator (Enexis) in conjunction with IBM, in response to upcoming legislation that will enable multiple trading relationships, it acts as an alternative for multiple smart meter setups.\textsuperscript{14} Large energy consuming IoT appliances (eg pool pumps and air-conditioners) will record their energy on the blockchain and provide the sub-metering data to the smart meter. Enexis, the meter operator, will then create billing determinant data based on the smart meter reads in combination with the blockchain.\textsuperscript{15} On a business level this means that concurrent energy delivery by multiple retailers can be facilitated (eg a different retailer to charge your EV vs power the home).\textsuperscript{16}

- **de-energisation and disconnection**: update the NERL so as to replace ‘connection point’ with ‘NMI’ so that each NMI is treated as a separate ‘premises’ for the purposes of the NERL. This would allow each service provider to disconnect and reconnect its individual load, independently of another service provider’s portion of the customer load.\textsuperscript{17}

The AEMC suggests that the rule change only allows for multiple trading relationships where separate disconnection of each settlement point is possible. While this seems logical, it may have the practical effect of limiting the availability of multiple trading relationships. An alternative option could include creating a ‘waterfall’ approach to disconnection so that a baseline of basic energy services is always required to be offered and all FRMPs are to share the respective costs (this is similar to the large customer regime whereby the retailer is given a right to charge if they are the FRMP for a customer where no contract is in place).

This waterfall approach is also reflected in the UK proposal described above - customers have a ‘main’ or ‘default’ supplier (similar to the concept of retailer of last resort in the NER) responsible for metering and data collection / aggregation. It is likely that this ‘main’ supplier would also be responsible for connection and disconnection.

- **customer protection**: the potential need for ‘qualifying criteria’ for customers who want to engage multiple service providers. Some suggested qualifications include:
  - only allowing large customers to engage multiple service providers
  - requiring each service provider to be able to disconnect and reconnect its individual load independently of the other service providers’ proportions of the customer’s load

While we respect and acknowledge that New Energy Services are not suitable for all customers, we suggest that further consideration be given to restricting the benefit of this rule change to only large customers. Limiting the application of multiple trading relationships to large customers only would narrow the range of people who could potentially benefit from such a rule change. As a starting point we suggest looking to alternative safeguards:

- hardship and life support customers be expressly excluded
- consumer protection safeguards under the NERL, NERR and Retail Code (as relevant) be amended so as to apply to and be relevant to new Market Participants (as above), in particular ensuring that Active Customers provide clear and active consent and are made aware of the higher level of risk associated with alternative energy service providers
- regulatory authorities should monitor systematically the above consumer protection safeguards, including whether offers from aggregators are adequate for residential electricity consumers or if the financial risk is too high for certain consumer groups. This analysis should include whether consumers receive clear, relevant and complete information to

\textsuperscript{14} Master thesis: Blockchain Technology in the Energy Transition, pages 114 and 122

\textsuperscript{15} Master thesis: Blockchain Technology in the Energy Transition, pages 114 and 122

\textsuperscript{16} See full consultation media release by the ACM for more details on the multiple trading relationships rule change in the Netherlands

\textsuperscript{17} AEMC, Reliability Frameworks Review Final Report (26 July 2018), page 155
accurately assess the risks and opportunities of entering into aggregation contracts and how consumer data is protected. A potential format for this could be AEMO’s yearly retail market review. Regulations should ensure that the regulator has the power to introduce additional protections as an expedited rule change if the monitoring indicates that revision is needed.

With this in mind, it is also important to recognise that the new Market Participant definitions will act as a ‘limit’ to the services that can be provided to individual customers (see Recommendation #1 above).

We can also look to international examples when considering regulatory change in Australia. These include:

**Netherlands and Belgium**

- Recently, the Netherlands implemented a code change to facilitate multiple trading relationships. The rule change came out of the Pantheon project, which researched changes to the Netherlands wholesale electricity market model to future-proof the market in the context of the current energy transition. The Netherlands Electricity Act 1998 did not explicitly prohibit multiple trading relationships, however there were several articles in the legislation that implied that there would be only one licenced supplier for each connection point. The code change started first with large scale commercial consumption connections and then extended the solution to small customer connections.

- It is clear that this rule change has created a dynamic environment for peer-to-peer and aggregator business models to expand, including Vandebron and Powerpeers.

- New legislation in Belgium addressing the role of aggregators and independent aggregation will soon be in place, following the Netherlands model – the central tenant of which is providing equal footing for all market actors.

**UK**

- A similar code change to the Netherlands has been proposed by Elexon in the UK. Importantly, the UK already has a concept of multiple service providers for large energy customers. The new code change extends this concept to residential prosumers. Elexon sets out a number of examples of the roles able to be played by multiple service providers, including:

  - Community energy schemes where a generator, such as a battery or photovoltaic (PV) cells, is owned communally and its export shared between members.

  - Electric vehicle (EV) manufacturers offering vehicles on a simple £/mile basis, including all the electricity needed to charge the vehicle (this could be at multiple charging points at different locations, subject to technology solutions to support appropriate measurement at the various locations). This could also apply to future ‘device as a service’ markets for household appliances in ‘smarter homes’ (for example, fridge rental with power included).

  - Peer-to-peer trading. For example, a customer buying a neighbour’s excess solar energy. This could be facilitated by the development of apps that allow consumers with micro-generation to sell (or give) their excess generation to other nearby consumers (rather than receiving the export feed-in tariff). For example, an app could be designed that allowed consumers to donate their ‘spill’ to local charities, or families in fuel poverty.

  - ‘Rapid switching’. Energy is purchased from different suppliers or wholesale energy sources for periods as short as a Settlement Period (Half Hour).

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18 Verdict CBb case Anexo ‘multiple suppliers on a connection’ – judicial decision 6 Dec 2018 – The Trade and Industry Appeals Tribunal ruled in December 2018 that Anexo’s challenge to ACM’s decision to change the code was inadmissible. The code changes were allowed to proceed and became law in 2018.

19 Code decision facilitating multiple supplies on a connection (18 July 2017)

20 SEDC Explicit Demand Response in Europe – Mapping the Market 2017, page 10
To facilitate this, the code change will require the creation of a new Part Agent role, the “Customer Notification Agent” (CNA). The CNA’s role would be to:

- notify BSC Central Systems of the Metering Systems for the consumers, generators and suppliers involved in energy trades or reallocations under the relevant scheme
- notify the associated energy volumes and ensure consistency with the existing contract notification regime
- notify adjustments to metered volumes to reflect volumes to be attributed to additional Suppliers.

The code change is still in its consultation phase, however is set to be implemented by April 2020.

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21 P379 proposal ‘Multiple Suppliers through Meter Splitting’ (8 February 2019) Elexon website
Current state of play

The National Electricity Market (NEM) is an energy-only, gross pool market with real-time (5-minute) scheduling and eight FCAS spot markets. The NEM is designed to send legitimate price signals to market participants so that supply and demand are in balance and the grid operates at a frequency range as close to 50 Hertz as possible.

To do this, AEMO would traditionally rely on both the NEM and FCAS markets to:

- balance the NEM demand and supply – by dispatching generation (every 5 minutes) to exactly meet forecast demand
- procure frequency control ancillary services (FCAS) - by contracting with generators that are able to increase or decrease output on direction.

At the time the NEM was designed, large, scheduled, centralised generators (coal, gas and hydro) supplied almost all electricity and FCAS. Other energy support services (such as physical inertia, system strength and voltage control) were essentially ‘bundled’ in with the cost of supply as they were inherent to centralised generators - there was no need to value them or incentivise generators to provide them.

However, in the last decade the NEM has seen the rapid rise of intermittent generation (including the penetration of distributed renewable sources) alongside the closure of many centralised generators. This is problematic for AEMO’s above approach as:

- intermittent generation (ie wind and PV) is non-dispatchable and their short-run operating costs are essentially zero. As such, intermittent generation typically bids into the NEM at zero to ensure that it is called on to generate. As such, intermittent generation does not respond to traditional market price signals and is thus problematic for balancing long term demand and supply
- intermittent generation is non-synchronous and non-dispatchable, meaning it does not provide the inherent support services we typically take for granted from centralised generation and also struggle (without paired technologies such as battery storage and flywheels) to provide FCAS, as they are unable to be scheduled (ie FCAS on-demand).

The AEMC is of the view that the NEM design requires adjustment to account for this shift and is taking active steps towards reforming market mechanisms so as to put in place the correct price signals and incentives to support the new energy mix. Similarly, in an advice to the Commonwealth Government, AEMO stated that "without extensions to the current market design, it cannot provide adequate and sustainable price signals to either maintain dispatchable capability or incentivise new development at the level necessary to maintain system reliability.”

It is clear that the AEMC has recognised that the valuing of all services (and arguably not just energy only) is crucial to ensure that the full value of services to the system is accounted for and that the correct investment incentives are in place. However, there are a still a number of barriers that prevent New Energy Service Providers (and therefore Active Consumers) from engaging and responding to price signals in the NEM and FCAS markets. For example:

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22 AEMO, Advice to Commonwealth Government on Dispatchable Capability (September 2017)
- **demand management**: under the current regulatory regime demand response is contracted directly between retailers and customers (and not, for example, on a central traded platform like the ASX).

- **ancillary services**: under the Market Ancillary Service Specification (MASS) all FCAS providers can only register a minimum amount of 1MW and must use high speed meters.

- **feed-in tariffs**: under the current framework, scarcity pricing promotes maximum self-consumption so as to avoid the costs of paying for retail provided energy. Flat tariff structures (and no tariffs for export of electricity) distort the cost of electricity and the benefits of electricity generation, particularly at a local or community level. Active Customers are encouraged by the current market mechanisms to consume their own generation – rather than demand managing and supplying excess generation to the NEM (at a lower cost to the system and retailers than central generation).

While mechanisms such as demand response and the FCAS markets have evolved to encourage greater participation and valuing of energy support services, these markets still require significant adjustment to ensure that New Energy Service Providers are encouraged and enabled to participate.

**Recommendations**

The Oxford Institute for Energy Studies states that the NEM and associated policy must accommodate not only energy, but a range of new and existing services that help to create wholesale real-time economic signals for the complex mix of services that are required for the comprehensive operation of a modern electricity network.

We recommend that AEMC continue its work in establishing new mechanisms, markets and contractual frameworks required to support NESPs.

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### Recommendation #3:

**Demand response mechanism established to allow New Energy Service Providers to bid demand response into the wholesale electricity market**

We support the AEMC recommendation that demand response providers be treated on equal footing to generators in the wholesale market, enabling them to more readily offer wholesale demand response in a transparent manner (rather than in traditional bilateral off-market contractual relationship).

There are currently a number of rule change requests that seek to facilitate wholesale demand response in the NEM:

- **wholesale demand response mechanism** - a mechanism that would allow third parties to offer demand response into the wholesale electricity market in a transparent, scheduled manner

- **wholesale demand response register mechanism** - a proposal that would introduce an obligation for retailers to negotiate in good faith with third parties looking to provide wholesale demand response through a register

There are a number of costs and questions that require further consideration including:

- determining a methodology for evidencing demand response and in particular defining an appropriate baseline (so as to not allow consumers to “game” the system by increasing energy consumption before forecasted peaks)

- the impact on other participants and consumers

- costs associated with system changes, including to AEMO’s settlement systems

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23 AEMC, *Wholesale Demand Response Mechanism* Rule Change

24 AEMC, *Wholesale Demand Response Register Mechanism* Rule Change
calculation or evidencing deferred investment costs and providing compensation / rewarding participants appropriately

costs of installing “smart” technology and changing systems to schedule the demand response. Further, the legal responsibilities of a New Energy Service Provider (as opposed to a Retailer) raise numerous questions, including:

- whether the demand response contracts (or offers) would constitute a financial product and if so if demand response providers would be required to hold appropriate licencing
- ensuring consumer protections are maintained – particularly with respect to the control of intelligent devices

We can also look to international examples when considering regulatory change in Australia.

The EU has acknowledged the benefits of demand response for flexibility in energy markets, proposing the following “recast” to Article 17 (Demand Response):

Member States must:

- encourage customers, including those offering demand response through aggregators, to participate alongside generators in a non-discriminatory manner in all organised markets
- ensure that networks, when procuring ancillary services, treat demand response providers, including independent aggregators, in a non-discriminatory manner on the basis of their technical capabilities.

Smart Energy Demand Coalition’s Explicit Demand Response in Europe – Mapping the Market 2017 report provides an extensive profile of Member State’s implementation of Demand Response.

The below map illustrates each Member State’s demand response development

The Member States will no doubt look to France as a model for implementing the new Article 17. The French model (known as the NEBEF mechanism) is one of the most advanced demand response mechanism in the EU.

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25 AEMC, Reliability Frameworks Review Final Report (26 July 2018), page 54
26 EU Legislation Briefing, Common rules for the internal electricity market
27 SEDC, Explicit Demand Response in Europe – Mapping the Market 2017, for France’s NEBEF mechanism see page 11
C&I customers have had access to demand response (both in wholesale and capacity markets) since 2017 and France is currently exploring way to integrate residential resources to harness distributed energy resources for demand response\(^\text{28}\)

Importantly for the Australian context (particularly as an energy only market), the NEBEF mechanism enables independent aggregators to perform load reduction without having to obtain permission from retailers and from a network point of view, reducing load is seen as the equivalent of producing energy. This principle is also reflected in the wholesale market bidding structure.\(^\text{29}\)

**Recommendation #4:**
Increase engagement and access to ancillary support markets and encourage further consideration of new support markets (if required)

We endorse the AEMC’s recommendations in the *Frequency Control Framework Review* that the existing rules relating to Market Ancillary Service Providers and Small Generation Aggregators be amended so as to allow New Energy Service Providers equal access to the FCAS market.

The Australian FCAS markets have historically attracted participation by synchronous generation (such as hydro, coal-fired and gas-fired generation). However, with the rise of distributed energy resources and the simultaneous withdrawal of synchronous generation it is clear that the level of FCAS will need to be supplemented by other sources. This is an opportunity for New Energy Service Providers.

AEMC has recommended in their Frequency Control Frameworks Review that the existing rules be amended to clarify that:

- Market Ancillary Service Providers are able to offer market ancillary services
- Small Generation Aggregators be enabled to offer market ancillary services

However, AEMC also recognises that there are technical challenges that will arise from allowing such participation. FACS via a large fleet of aggregated resources may have localised network impacts (eg voltage) or may negatively impact power system security. This issue was also identified in the EU. As a solution the EU proposed that where system impact could be identified and evidenced, aggregators may be required to pay compensation for system damage.

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\(^{28}\) SEDC, *Explicit Demand Response in Europe – Mapping the Market 2017*, for France’s NEBEF mechanism see page 81

\(^{29}\) Deloitte, *Reaching the optimum: from monopoly to aggregators*, page 17
Current state of play

AEMO is responsible for balancing supply and demand and ensuring the secure and reliable operation of the network. Importantly, as an independent market operator AEMO is technology neutral, and primarily focused on ensuring the resources available to it meet the demands of the system at the time and location necessary.

To fulfil this role, AEMO requires:

- **Appropriate mechanisms for trading generation and support services**
  Currently, AEMO utilises reverse auction dispatch bidding and direct contracting of non-market ancillary services. Traditional generators are (for the most part) dispatchable. As such, AEMO’s most appropriate mechanism for generation and support services has traditionally been centralised dispatch. AEMO relies on the NEM dispatch engine software that operates in accordance with the Power System Operating Procedures. The NEMDE co-optimises with the FCAS market so as to issue dispatch instructions (electronically via the automatic generation control system (AGC) or the AEMO Electricity Market Management System (EMMS) interfaces).³⁰

- **Sharing and access to data to inform demand forecasting**
  Under the current regulatory regime, AEMO has (or will soon have) access to data for three fundamental functions:
  - forecasting demand - the data required for this function includes the data on the Distributed Energy Resources Register NMI Standing Data and accurate weather data
  - dispatch and global settlement - the data required for this function includes forecast interconnector flows, constraints, regional reference price, demand, dispatchable generation, dispatchable load, and ancillary services data
  - providing information to the market - AEMO operates the e-hub for transactions between market participants and systems for participants to share information within the market

  For more information about the current access arrangements to energy data see Section 3 of “More Details”.

- **Market co-ordination among all market participants**
  Currently, co-ordination between NEM market participants is relative simple as there is only one market participant per connection. However, with the potential for multiple FRMPs at any one connection point and the sharing of responsibilities, the requirement for co-operation of multiple service providers will be essential.

³⁰ AEMO, *Advice to Commonwealth Government on Dispatchable Capability* (September 2017), page 2
Recommendations

Recommendation #5:
Establish and provide support for Distribution System and Market Operators (DSMOs) to oversee mechanisms for control and trading of New Energy Services, including demand response, aggregated generation and peer-to-peer

Previously, grid control services and generation could be procured (and subsequently dispatched) from centralised generation on a relatively equivalent basis. However, now the role of a market operator in allocating and dispatching resources to achieve balance is resoundingly complex. This is because the functional capacities of distributed energy resources are not equal (see Section 4 of “More Details”).

Drawing on the extensive work AEMO and Energy Networks Australia have conducted as part of their Open Energy Networks consultation, we recommend that Distribution System and Market Operators (DSMOs) be established to oversee mechanisms for control and trading of New Energy Services at the distribution market level (including demand response, aggregated generation and peer-to-peer).31 This role, similar to AEMO’s role, will be responsible for:

- distribution system operations (i.e., safe, reliable and efficient operation of a local distribution system)
- distribution market operations (i.e., operation and management of a market platform to ensure that all participants meet registration requirements, information transparency, dispatch reconciliation and market settlement)

The DSMO, which may be an independently run marketplace/platform or a combination of multiple service providers (i.e., networks, energy management providers, platform providers and aggregators) working together to create a marketplace/platform will be required to interact with AEMO for centralised dispatch.

However, consistent with many submissions to the Open Energy Networks consultation we believe that the DSMO model should not be ‘picked’ at this time. Instead, we recommend a staged approach – whereby AEMO continues to act as the whole of market operator and by doing so co-ordinates and directs the framework for distribution system operation.

This means that AEMO will play a vital role in developing and implementing the framework for how the new distribution system is managed and operated. This is important as it allows AEMO to leverage off its experience as an operator and ensure that the framework remains independent of any market participant bias. Having a staged approach will ensure that we do not stifle innovation and competition among platform providers or hard-wire in the ‘wrong’ approach. In time, we acknowledge that this system/management role may be localised so as to lend itself to independent operators that have developed platforms suitable for distribution operation management at local levels (such as LO3’s Exergy and GreenSync’s Decentralised Energy Exchange platform).

We understand that the OpEN team is working to develop models on how co-ordination can be achieved based on the view that incremental (or staged) changes are required. We also acknowledge and support the team’s view that while incremental changes are the goal, first they need to look at developing a ‘future framework’ so as to ensure that the changes are not “piecemeal, rendering the industry incapacitated at a future point in time when redesign will be difficult”.

In taking a staged approach to the establishment of a DSMOs, we recommend that:

- all changes are designed to ensure flexibility, so that they are easily changed, adapted and modified to evolving market conditions

31 Energy Networks Australia, “Are we there yet?” article by John Phillpotts and Ryan Wavish (28 September 2017)

32 Open Energy Networks, Consultation Response, pages 18 and 20
AEMO, as the current market operator, is supported in keeping pace with change (including funding for IT system upgrades and development of new platforms)

AEMO (and other New Energy Service Providers in the platform development space) be encouraged to develop and apply standards protocols (including APIs, open source code and communication) to ensure that, even during transition, any changes are focused on accommodating New Energy Services.

As a starting point, we recommend establishing frameworks for co-ordination and dispatch arrangements. This would include determining the appropriate scheduling and dispatch requirements to attempt to account for (currently invisible) behind the meter controllable loads in central dispatch or alternatively, co-optimised load and demand models.

Recommendation #6:
Facilitate data access and sharing between Market Participants, while maintaining privacy and confidentiality protections

The volume of data being generated, processed and stored has been increasing and will continue to do so as the energy market responds to the rise of smart metering and real time settlement and distributed energy generation. As the market moves towards further storage and generation of distributed energy, greater visibility of the distribution system (including at and behind every connection point) will be needed, particularly as AEMO seeks to maintain network stability and ensure balance of supply and demand.

To increase access to and use of relevant data we recommend that the following be considered:

- **data access and availability** – there are a number of datasets that will be required to ensure New Energy Service Providers are able to provide their services. The Consumer Data Right sets out a number of datasets that are considered relevant to consumers (see Section 3 of “More Details”). Equally these datasets are crucial for New Energy Service Providers to be able to provide customers with new and competitive services.

- The ACCC’s recent consultation paper titled “Consumer Data Right in Energy” explores the access model appropriate for energy data (summarised in Section 4 of “More Details”).33

- We recommend that regulators and industry look to experiences overseas when considering what access model to adopt. The Netherlands is an interesting framework for Australia to consider, particularly as the Dutch have a similarly high penetration of distributed renewables and significant system balancing challenges. In 2007, the Dutch set up EDSN as a “central data hub”. EDSN currently provides the following services:

  - customer portal giving customers control over their own data
  - central service to store and exchange data on both centralised and distributed power-generating facilities in the Netherlands for all market participants
  - centralised and uniform allocation and reconciliation processes that allow distributed energy resources to interface with the wholesale market

In this way, we encourage policy reform in the data space to look beyond the current use cases for energy data (such as comparison sites and customer switching) and towards the future data use cases, including in particular using residential energy data to co-ordinate, control and interface with the wholesale market.

- **data governance and privacy** – security, privacy and governance of data sharing needs to be considered and thoughtfully addressed. Distributed energy raises concerns as data can potentially

33 ACCC, Consultation paper on energy data access models (25 February 2019)
include personally identifiable information from NMI, household consumption patterns and customer billing information.

We understand that the ACCC Consumer Data Right in energy will further explore the role of data governance and privacy in relation to data sharing. We strongly encourage privacy by design principles and further technical measures to protect privacy and data governance, be integrated into any data sharing regime.\(^{34}\)

- **communications infrastructure and standards** – in general, distributed energy resources are smaller and more geographically diverse than traditional power plants. In order to extract value from distributed energy resources, both as a service and for grid flexibility, communication infrastructure is essential. The system must also be sufficiently robust to resist cyber-attacks, provide system stability and reliability and operate in near-real time. Further, the adoption of interoperability standards, such as the work Standards Australia and the Energy Networks Association are doing in this space, along with open data sharing for the overall energy system, is recommended as it will ensure that new technologies and developments are interoperable.\(^ {35}\)

- **consent** – in most cases, sharing and using data is acceptable under the Privacy Act if it takes place with the consent of the data subject. Currently, consent must be obtained in a transparent, fair and voluntary manner.

However, we recommend that – as part of the ACCC Consumer Data Right in Energy consultation - the nature and appropriateness of the current consent regime in energy be considered. As energy is an essential service, it is difficult to see how consumers would be able to withhold consent if it is bundled with their service offering, making the consent effectively involuntary. As more data is being shared, collected and accessed from consumers than ever before, it is crucial that customers are protected. We encourage regulators to consider alternative consumer protections such as prescribing “permitted uses” for all Market Participants when using consumer energy data.

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**Recommendation #7:**

*Mandate cooperation between traditional Market Participants and New Energy Service Providers and establish appropriate dispute resolution mechanisms, including establishing rules and procedures for financial licencing, billing, data exchange and security*

As the distribution network and associated markets become more complex, co-operation between market participants (particularly those at the same connection point) will become increasingly necessary. We recommend that consideration be given to the Distribution Systems and Markets Operators be charged with the role of not only appropriately managing the levels of co-operation but also overseeing potential disputes between market participants.

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\(^{34}\) ACCC, *Consultation paper on energy data access models* (25 February 2019)

\(^{35}\) KWM, *Energy Storage Registration COAG Submission number 37* (20 September 2016)
Current state of play

The changing nature of the energy market will have a significant impact on the distribution network.

A key value proposition of New Energy Service Providers is their ability to support network service providers:

▪ with power system planning and maintenance so as to reduce spending on network infrastructure
▪ in operating their networks within technical and safety requirements
▪ in reducing congestion, smoothing network peaks and mitigating outages
▪ reduce or avoid transmission costs

Ideally, these benefits can then be passed onto consumers through lower network pricing.

There have been a number of significant positive developments in the network space that show strong buy-in from network operators and regulators in support of the potential benefits that distributed energy resources can provide. However, despite this, a number of structural challenges still act as barriers to New Energy Service Providers, particularly in the 3 areas below.

Network transparency and data

Imperfect information, including low visibility of network assets, and lack of data sharing can act to inhibit the realisation of New Energy Service Provider benefits, particularly in relation to network infrastructure costs and network planning decisions.

The lack of network asset visibility has resulted in less than desirable outcomes, including:

▪ limiting exports from distributed energy resources to the grid
▪ inability to value the benefit of New Energy Services
▪ information asymmetry when negotiating with network and retailers

Zero Offset and augmentation

The NER requires Network Operators to offer solar PV customers connection to the grid. Subject to the terms of their Connection Agreement, customers import/export electricity to the grid. However, it has been publicised that Network Operators are ‘offering’ connection to solar PV customers at a maximum capacity of “0” export. While this may comply with regulatory obligations, it is not particularly conducive to the growth of Active Consumers.

Network pricing

In Australia, network tariffs make up approximately half of the average Australian households bill. As such, it is equally important that Active Consumers receive the correct price signals from networks as they do from retailers. Cost reflective pricing is important. It means that consumers will pay (nearer) to the
actual cost of obtaining or providing electricity at different times and to different locations. This is particularly important in the context of New Energy Services and the business models that accompany them. AEMC has enacted significant rule changes in an effort to encourage cost-reflective network pricing (see Section 2 of “More Details”), however there has to date been limited take up of this new model of network pricing.

Why have the benefits of cost-reflective network pricing not materialised? The reasons could include:

- **opt-In:** while most networks now offer small customers cost-reflective network tariffs with robust methodologies, there are a range of barriers from metering, to industry structure, to behavioural preferences, which severely limit customer take-up. These are well documented in the 2016 publication, the *Electricity Network Tariff Reform Handbook*.

- In particular, the Australian Energy Regulator (AER) indicated in its Tariff Structure Statements that positive impacts won’t be achieved just by offering tariffs, in the absence of a more proactive strategy by networks to migrate small customers to these tariffs.

- According to the Network Tariff Reform Handbook, international experience suggests that assignment and opt-out approaches deliver more certain and quicker transitions to cost-reflectivity. However, this has not been the approached implemented in Australia. In fact the opposite has occurred in Victoria, where a State Government Order in Council was introduced preventing the assignment of customers to cost reflective prices, even where the customer retained the opportunity to ‘opt out’ to current tariff structures.

- **structural barriers:** while under the rule change, networks are permitted to take into account the location of consumers and the extent to which costs vary between different locations in their distribution network when determining LRMC, in reality, many State regulations prohibit this. For example, in Queensland, Tasmania and South Australia, small customers must be offered the same tariff regardless of their location. As this is a jurisdictional pricing obligation, it takes precedence over the rule change.

**Recommendations**

**Recommendation #8:**
Enhance and maintain the visibility of and data available on the component parts of the distribution network

Increasing data sharing among Market Participants is beneficial (see recommendation #7) however the availability of adequate distribution data is also required to ensure all Market Participants are able to assess the true cost and value of electricity services.

We recommend that distribution networks are incentivised to increase the collection of data to provide all Market Participants better visibility of the component parts of the distribution network. This will provide New Energy Service Providers sufficient information to target their services to avoid or mitigate grid augmentation requirements and costs.

Network co-ordination and balancing requires significantly more active power system management. However, as distributed energy resources are typically installed behind the meter, these resources are invisible to AEMO and network operators and cannot be actively managed. AEMC recently determined a rule change that has the potential to increase the visibility of distributed energy resources. However, the rule change is limited and we recommend that the register be built-on (in stages) to ensure that the register is beneficial to all Market Participants both now and in the future. Incremental changes that would benefit New Energy Service Providers and Active Consumers include:

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37 AEMC, *Distribution Market Model Report* (22 August 2017)
38 AEMO, *Submission to Government Inquiry into modernising Australia’s electricity grid*, page 5
allowing New Energy Service Providers simple and seamless access to data on the AEMO registry, provided the New Energy Service Provider has adequate customer consent.

expanding the register to include real-time data. Currently, AEMO monitors real time loads of large energy generators. In the future embedded generation and data associated with aggregated loads will be just as valuable, if not more valuable. In particular real time data will result in improved customer information, control and choice.  

Recommendation #9:
Mandate opt-out cost-reflective network pricing for retailers and remove structural barriers for uptake of cost-reflective pricing

The AEMC has already enacted significant rule changes to network pricing in this regard, however there has been limited take up to date of AEMC’s new model of network pricing. We recommend, in line with the ACCC Retail Electricity Pricing Inquiry – Final Report, that cost-reflective pricing be opt-out (rather than opt-in as it is currently) and that the State legislation that creates structural barriers to the uptake of locational based pricing be removed or amended.

Recommendation #10:
Require networks to engage in good faith negotiations with New Energy Service Providers regarding network charging

Cost-reflective pricing (as above) is a positive step forward for Active Consumers, however there are many other alternative pricing models that may provide better outcomes (particularly for those involved in peer-to-peer trading). We recommend that, similar to the negotiated connection regime in Chapter 5, distribution networks be required to negotiate with New Energy Service Providers regarding network charging when benefits (such as grid augmentation avoidance) can be evidenced.

We also recommend consideration be given to the following as part of the process:

- **information equity** – requiring the Networks to provide (or collect if necessary) the data / information reasonably necessary to allow the New Energy Service Provider to negotiate on an informed basis (similar to Chapter 5A.C.3)

- **planning report** – requiring the Networks to provide to New Energy Service Providers network planning reports (similar to clause 5A.C.3)

- **timeframes** – mandate a maximum negotiation timeframe and response requirements for the Networks in respect of a New Energy Service Provider’s application (see Chapter 5A.D.3)

- **solution support** – requiring distribution networks to work with New Energy Service Providers to negotiate pricing for solutions that integrate distributed energy resources on a case by case basis (this goes further than the connection requirements – removing the current issues that are being seen with Chapter 5A (ie zero export)).

While cost-reflective pricing has been the chosen model in Australia, there are other alternative pricing models that may provide better outcomes for New Energy Service Providers and their Active Customers. We set out three alternative pricing models below, and recommend that rather than enshrining one model of pricing, New Energy Service Providers are empowered to negotiate the most suitable pricing model with distribution networks on a case by case basis.

KWM, *Energy Storage Registration COAG Submission number 37* (20 September 2016)

ACCC *Retail Electricity Pricing Inquiry – Final Report* “Restoring electricity affordability and Australia’s competitive advantage”, page xix
Local generation network credits

The use of “Local Generation Network Credits” was proposed as a rule change in 2015 by the Property Council of Australia, the City of Sydney and the Total Environment Centre. The regime attempted to provide networks with a mechanism to price local electricity generation and consumption separately (and a lower rate) than consumption of centralised generation. In summary, the proposed rule change required networks to:

▪ calculate the long-term cost savings that generators of distributed energy (embedded generators) would provide to the distribution and transmission networks
▪ pay a local generation network credit (LGNC) that reflected those cost savings to all eligible embedded generators in their network area

The AEMC rejected the LGNC rule change proposal and stated that existing provisions for network support payments, combined with cost reflective tariffs, were sufficient to incentivise efficient local generation. While LGNC’s are desirable in theory, there are major concerns with this approach. Most notably, the non-selective nature of the LGNCs will likely result in embedded generation being incentivised in areas where there are no system limitations, and a lack of investment in embedded generation where system limitations exist.

On the positive side, as a result of the LGNC rule change request, the AEMC did implement a change that required networks to annually publish system limitation information on:

▪ the geographical location and estimated duration of a system limitation identified during the forward planning period
▪ the network’s proposed solution to remedy the system limitation and the estimated costs of the network’s proposed solution
▪ the amount by which peak demand at the location of the system limitation would need to be reduced in order to defer the proposed solution and the dollar value to the network for each year of deferral

The above information requirement (coupled with existing network incentives) is a step towards encouraging networks to look to distributed energy resources for abatement – opening the potential for New Energy Service Providers to negotiate with networks to adjust or alter network tariffs based on potential value streams they could provide through local peer-to-peer trading and abatement. This would not however be a regulated mandate but rather a commercial decision for the network to consider and propose in their tariff setting process.

Local use of network service (LUOS)

Similar to the LGNCs is a change to network charging that would see networks offer local Active Customers who assign (or trade) excess electricity with other Active Customers (in a VPP or P2P scenario) an appropriately lower network charge for use of only the local network. Going further, this alternative model could be applied in a VPP / P2P scenario so that two Active Consumers could share the LUOS based on the network infrastructure required for the trade.

International example

The EU’s Clean Energy for all Europeans package sets out an interesting approach in the recently implemented change to the Renewable Energy Directive Article 22(4)(d). It states that:

“Member States shall provide an enabling framework to promote and facilitate the development of renewable energy communities. That framework shall ensure, inter alia, that renewable energy communities are subject to fair, proportionate and transparent procedures, including registration and licensing procedures, and cost-reflective network charges, as well as relevant charges, levies and taxes, ensuring that they contribute, in an adequate, fair and balanced way, to the overall cost

41 AEMC, Local Generation Network Credits Rule Change (10 December 2015)
An example of a business model taking advantage of this new right is Next Kraftwerke’s “German project”. Next Kraftwerke provides ‘midscale’ customers with time variable tariffs including ‘grid-charge optimisation’ to help consumers benefit from market signals through time variable tariffs while also taking into account grid charges. It is Next Kraftwerke’s view that by optimising the capacity tariffs and individual network tariffs, customer revenues can be optimised.43

Recommendation #11:
Better integrate renewables by investing in and managing the grid so as to avoid zero export

The European Commission has proposed a number of new legislative requirements on all Member States, as part of a reform to the EU’s electricity market design, to give equal access to all energy providers. This includes residential solar.44

Specifically, the following Directive / Regulatory changes have been proposed:

- **Renewable Energy Directive, Article 21**: that renewables self-consumers, individually or through aggregators, are entitled to generate renewable energy including for their own consumption and store and sell their excess production of renewable electricity, including through renewables power purchase agreements, electricity suppliers and peer-to-peer trading arrangements, without being subject to discriminatory or disproportionate procedures and charges or to network charges that are not cost-reflective45

- **E-Directive, Article 15**: that “final customers” are entitled to generate, store, consume and sell self-generated electricity in all organised markets either individually or through aggregators without being subject to disproportionately burdensome procedures or charges46

- **Electricity Regulation, Article 3(1)(d)**: that market participation of consumers and small businesses shall be enabled by aggregation of generation from multiple generation facilities or load from multiple demand facilities to provide joint offers on the electricity market and be jointly operated in the electricity system, subject to compliance with EU treaty rules on competition47

Using the EU as an example, we recommend that Chapter 5A be amended to ensure that solar connection and export is adequately supported (rather than individual customers being obliged to pay for grid augmentation) with the costs of this being shared fairly and reasonably among all energy market participants and customers. We acknowledge, in saying this, that the costs of grid augmentation will need to be carefully balanced against the benefits this will deliver to the consumer and more broadly to the future transition to a flexible energy mix.

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43 *Engerati*, "Business models for renewable aggregation – what is ready" (27 September 2018)

44 European Commission, [Clean energy for all Europeans](https://ec.europa.eu/energy/en/topics/renewable-energy) (website)


Section 1: Current retail framework

Below we set out how new business models operate within the current framework, highlighting some of the restraints that the current framework places on the business models of New Energy Service Providers.

Operating as a Retailer

Section 88 of the NERL requires that anyone who sells energy to people for use at premises must have either a retailer authorisation or a retail exemption. Energy sales do not necessarily have to be for profit – passing on energy costs to another person is considered to be a sale.

New Energy Service Providers could act as a traditional retailer, offering a new model of pricing and alternative services. This would allow the New Energy Service Provider to have full control over the local energy marketplace, allowing it to implement any pricing model (including reflecting spot market pricing or ‘netting off’ between local market participants). However, this option would also require the New Energy Service Provider to take on 100% of the risk, including the complexities of retail businesses such as hedging, prudential requirements, settlement, billing and compliance.

While it is possible for New Energy Service Providers to be licensed as retailers, it is questionable if this is the most desirable outcome. In particular, New Energy Service Providers:

- are often at the infant stage of commercialising new or innovative products. As such, it is unlikely that they have the capital, expertise and systems to take on all the responsibilities and risks of a retailer. There is a real concern that requiring New Energy Service Providers to be licensed will ‘freeze out’ new entrants and in turn dampen innovation in the NEM.
- offer a different service to traditional retailers. Most commonly, New Energy Service Providers sell flexibility and trade it on the NEM on behalf of Active Consumers. Active Consumers offer New Energy Service Providers a number of ‘tradeable products’ including:
  - excess solar generation
  - avoided consumption during times of grid restraint
  - grid-stabilising services (i.e., FCAS and ancillary services)

This business model is fundamentally different from that of traditional retailers as its focus is not on the consumption of electricity, but rather flexibility of demand. In reality the two should offset each other leading to lower overall energy costs for the Active Consumer.

Partnering with a Retailer

New Energy Service Providers which do not wish to be licensed as a retailer can partner with an authorised retailer to provide ‘secondary’ services. The retailer remains responsible for all settlement and billing as the Financially Responsible Market Participant. While this is currently permissible under the NER, it requires a willing retailer to cooperate with New Energy Service Providers. Under this model the delineation of liability and responsibility is complex, and negotiations by New Energy Service Providers with established retailers often place a large strain on resources.
It is also important to understand that traditional retailers and New Energy Service Providers can have opposing interests. At a basic level, traditional retailers sell electricity, deriving profits from consumption from the grid, whereas New Energy Service Providers sell flexibility and aggregated generation. The co-operation model, currently seen as the more viable option for New Energy Service Providers entering the Australian market may therefore prove difficult to put in place with retailers, and even if put in place, prove counterproductive for the New Energy Service Providers and the Active Consumer. This model may:

- stifle competition in the energy market, forcing consumers to enter into set tariff structures with the retail partner. This undermines the right of consumers to switch retailers and choose their own tariff structures
- decrease the offering of New Energy Service Providers, particularly in the area of demand response where retailers are traditionally paid by customers for consumption
- increase the risk profile for the retailer (for example the New Energy Service Provider may have control over the price that energy is bought or sold by the retailer in the wholesale market)
- stifle the New Energy Service Provider’s offerings and innovation (as the retailer may not be comfortable with another party influencing wholesale purchasing decisions).

This co-operation model creates an unregulated ‘quasi’ market participant, with the only recourse being contractual obligations to the retailer.

**Operating as an exempt Retailer**

Another option for New Energy Service Providers is to operate under the Australian Energy Regulator’s exempt seller regime. This regime enables companies to offer New Energy Services without becoming a FRMP and an authorised retailer. This would enable a New Energy Service Provider to buy and sell electricity on behalf of customers without a retail licence. Utilising the individual exemption framework, it is possible that the AER could decrease some of the regulatory requirements, in effect tailoring the licencing regime of traditional retailers for a New Energy Service Provider. In fact, the AER can:

- impose conditions as it chooses and these conditions can be tailored to the scope and nature of activities being undertaken. Generally, conditions will relate to the sale of electricity to exempt customers and conditions on pricing and prudential standards
- set a term of the exemption, ensuring a review of the exemption is undertaken regularly

However, we must recognise that traditional retail relationships provide customers with security and protections. When looking for regulatory change, it is crucial not to underestimate the role of the retailer as a provider of security for energy consumers – retailers act as a buffer to spot market price fluctuations and also ensure security of supply.

If the AER were to go down this path of ‘quasi-licencing’, options include:

- defining eligible customers (ie ensuring that Hardship Customers or other vulnerable customers are not able to sign up to New Energy Service Provider’s offerings)
- requiring the New Energy Service Provider to engage with a traditional retailer to satisfy conditions such as prudential standards and billing
- imposing regular reviews and licence condition audits to ensure customers are satisfied and protected

The UK has taken active steps to formalise such an approach. In 2015, “Licence Lite” was introduced by Ofgem as an alternative electricity supply licensing option. The regime was intended to “ease potential barriers to entry faced by aspiring suppliers”. Under the Lite supply licence, an energy supplier could outsource the more complex ‘compliance’ burdens to Third Party Licenced Suppliers. In effect, “piggy-backing” on a retailer’s licence, while still being able to remain the sole supplier of electricity to customers.

Originally, Ofgem intended that this model would support small-scale electricity generators to enter the retail market and supply local customers. However, it seems that prospective suppliers have seen the
benefits of the Licence Lite model as an alternative to the restrictions imposed by the primary route to supply, the “Class Exemption Order”. For example, Evenergi UK Limited, a home and electric vehicle energy usage monitoring company, was the first to be approved under the Licence Lite regime. It is unclear at present what plans Evenergi has with respect to its retail offering, however this example highlights an innovative regulatory solution which facilitates new business models in the retail energy space.

While the Ofgem ‘Licence Lite’ model has not yet proved resoundingly successful, it is a positive regulatory change in regard to facilitating choice – allowing New Energy Service Providers to be the FRMP while also acknowledging the role traditional retailers play in consumer protections and compliance.

**Market Small Generation Aggregator**

In 2012, AEMC passed a rule change that created a new Market Participant – the Market Small Generation Aggregator (MSGA).\(^\text{48}\) The framework was established to allow the owners of small generating units to have the additional option of selling electricity from those units to a Small Generation Aggregator instead of a Market Customer. Under this rule change, the MSGA (or the owner of the small generating units) does not have to register as a Generator with AEMO to directly participate in the NEM.

However, as discussed above, each connection point through which energy is imported must have a Financial Responsible Market Participant. Given this, if there is only a single connection point, and energy will be imported and exported through it, an MSGA is effectively required to also hold a Retail Licence.

Clause 2.3A.1 of the NER also precludes an MSGA from participating in market ancillary services - it can only provide energy services.

Due to the above restrictions, MSGA service models are currently limited to the large customer segment of the market, as these are the customers likely to find it economical to establish a second connection point for the purposes of selling embedded generator output.

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\(^{48}\) Clause 2.3, National Electricity Rules
Section 2: Multiple Trading Relationships – rule change attempts

In December 2014, AEMO requested a rule change to enable consumers to enter into trading relationships with multiple financially responsible market participants. It proposed the establishment of multiple trading relationships at a premises. AEMO stated that the current rules were overly costly and complex, acting as an unjustified barrier to the kind of services that New Energy Service Providers can offer.

In February 2016, the AEMC declined to make the rule change, stating that while a small number of consumers would benefit from multiple trading relationships, most would not experience any reduced costs. Further, the AEMC said that the proposal would require significant, costly modifications to retailers’ and DNSPs’ systems. These costs would likely be passed on to all consumers in the form of increased electricity retail prices. As an alternative, AEMO suggested that if consumers wanted to engage two service providers they would require dual connection points. The costs of this “solution” were significant as it required:

▪ investment to rewire the premises to establish the second connection point
▪ investment to install a second meter at the premises
▪ the payment of dual network tariffs.49

This solution, to our knowledge, has not been taken up by any New Energy Service Providers – most notably as it not palatable to consumers as the costs are seen as both unnecessary and duplicative.

AEMC in their 2018 Reliability Frameworks Review recommended that AEMO submit a rule change request to AEMC by the end of 2018 (which at the date of this paper has not yet occurred) to allow customers to engage multiple service providers behind the same connection point. AEMC proposed that New Energy Service Providers would be allowed to be a FRMP behind a connection point for a subset of the resources (such as selling generation to the wholesale market or engaging in demand response) without becoming the FRMP for all of the load behind the connection point.

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# Section 3: Energy data access

The ACCC consultation on the Consumer Data Right in energy sets out the current access arrangements:

<table>
<thead>
<tr>
<th>Type of data</th>
<th>AEMO</th>
<th>AER/Victoria Energy Compare</th>
<th>Retailers</th>
<th>Metering Data Providers</th>
<th>Distributors</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>NMI Standing data</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Connection point information</td>
<td>∙</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Customer provided data</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Name of account holder, contact details including billing address/postal address, information provided re customer appliances, etc.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Metering data</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Data collected by metering data providers or otherwise estimated or substituted by Metering Data Providers. AEMO does not currently hold all metering data (it is not as rich as what other market participants hold).</td>
<td>∙</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Billing data</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Historical billing information for each connection point to which they have delivered electricity</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Product data - generic</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Retail tariffs, usage charges, applicable discounts for the supply of electricity to consumers</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Product data – individually tailored</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Retail tariffs, usage charges, applicable discounts for the supply of electricity, specific to a consumer</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Distributed Energy Resource Register</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Section 4: Access Model

Model 1, the AEMO centralised model – AEMO would be the sole data holder of the centralised data set, which includes consumer energy data that it currently does not hold and would be responsible for providing CDR data directly to accredited data recipients. This would require:
- data holders to build APIs to provide CDR data to AEMO for centralised storage; and
- AEMO to build open APIs to provide that data to accredited data recipients (which could include those outside the energy industry – which is both exciting and concerning for bundling products).

Model 2, the AEMO gateway model – AEMO would provide a gateway function (acting as a pipeline for the provision of CDR data from data holders which may include retailers and potentially also distributors, to accredited data recipients) and may also be a data holder providing CDR data directly to accredited data recipients. This would require:
- AEMO to build a gateway through which AEMO (on behalf of energy data holders) provides CDR data to accredited data recipients;
- Data holders to build web-based APIs that enable ‘on demand’ provision of various energy data sets.

Model 3, the economy-wide CDR model – existing data holders (for example, retailers) would be responsible for providing CDR data directly to accredited data recipients and/or consumers i.e. the model used for the banking sector. This would require:
- Accredited data recipients and/or consumers themselves directly contracting the data holder responsible for collection and management of relevant data sets;
- Participants and potentially also AEMO and government-provided energy comparator services to build open APIs for the provision of data accredited data recipients.

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50 ACCC, Consultation paper on energy data access models (25 February 2019)
Section 5: DER coordination challenge

51 Energy Networks presentation, Energex Brisbane 2016 page 50
Section 6: Network pricing

Before looking at how network pricing can be more cost-reflective, it is important to recognise the significant changes in regulations that have acted to help address network pricing and why network pricing is the way it is currently.

Originally, each consumer was required to pay a proportion of total network costs depending on their level of consumption – this pricing model operated irrespective of timing (peak or non-peak use of the grid) or location of that consumption. This structure aimed to over-recover revenue for off-peak prices and under-recover for peak use, was clearly not cost-reflective and led to a situation where customers who used off-peak power were paying more and those using peak power were paying less.

Further, the principle of equal access to the grid underpinned much of the network regulation until very recently. Under this pricing structure, the costs of the network fall disproportionately on those who rely on the network for their electricity compared to those who rely on it only partially (due to solar and/or batteries). The impact of this is that households are encouraged to self-consume, rather than feeding electricity back into the grid. This incentive is particularly perverse if you have a short fall in supply or if you consider that local energy can be less of a strain on the electricity grid (ie electricity does not have to travel through as much of the grid). Further, it arguably undervalues the back-up or insurance value of the grid and creates a form of cross-subsidisation from those who do not generate electricity by those who do.

As a reaction to these concerns, AEMC implemented a rule change in 2014. The rule change established a new pricing objective for networks, focused on cost-reflective pricing. The rule change was aimed at ensuring networks take into account how future costs vary by location and time of peak utilisation, and signalling these cost drivers to consumers. Under the rule, networks are required to comply with 4 new pricing principles:

- network tariffs must be based on the long run marginal cost (LRMC) of providing the network service
- total revenue to be recovered (as determined by AER) must be recovered in a way that minimises distortions to price signals and encourages efficient use by consumers - DNSPs may determine how this is done and are subject to a number of constraints in doing so
- tariffs must be developed with regard to the impact on the consumer and networks must develop pricing structures that can be understood by consumers
- network tariffs must comply with jurisdictional (State and Territory) pricing obligations in a transparent way\(^\text{52}\)

The purpose of the rule change was to encourage investment in energy efficiency technologies, west-facing solar panels (for generation at peak times), battery storage and locating businesses in areas where network costs are lower. It was anticipated that consumers would respond to new network price structures by reducing their use of the network at peak times, thereby reducing overall network costs. The cost saving would then be passed on to all consumers through lower future network charges, although how the cost of "stranded" investment would be recovered remained unresolved. The pricing structures applied from January 2017 and were rolled out on a network-by-network basis in accordance with regulatory determinations.

The AEMC rule change and the move toward cost-reflective pricing is significant. Despite the potential value of the reform to customers, the benefits of it are yet to be realised. In March 2017, Energy Networks Australia illustrated with the below graph the lack of consumer take up for the new network pricing structures:

However, the lack of take up is not the only issue that continues to plague network pricing reform.

<table>
<thead>
<tr>
<th>NEM Region</th>
<th>Average years alternative cost reflective tariffs available</th>
<th>Customers still assigned to legacy volume tariffs (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSW/ACT</td>
<td>14</td>
<td>88%</td>
</tr>
<tr>
<td>QLD</td>
<td>5</td>
<td>100%</td>
</tr>
<tr>
<td>VIC</td>
<td>14</td>
<td>89%</td>
</tr>
<tr>
<td>SA</td>
<td>2</td>
<td>100%</td>
</tr>
<tr>
<td>TAS</td>
<td>8</td>
<td>100%</td>
</tr>
<tr>
<td>NEM</td>
<td>11</td>
<td>92%</td>
</tr>
</tbody>
</table>
Section 7: Regulatory reform and government reviews

1 Government Reviews / Inquiries:
   ▪ Finkel Review Independent Review into the Future Security of the National Electricity Market (June 2017)
   ▪ Report for DoEE Facilitating access to consumer electricity data (Feb 2018)
   ▪ ESB and AEMO Annual report into the cyber security preparedness of the NEM (Dec 2018)
   ▪ Commonwealth Government Inquiry into modernising Australia’s electricity grid (Feb 2017)

2 AEMC Reviews/ Inquiries:
   ▪ Distribution Market Model Review (August 2017)
   ▪ Reliability Frameworks Review (July 2018)
   ▪ Frequency control frameworks review (July 2018)

3 AEMO advice to government:
   ▪ Advice to Commonwealth Government on Dispatchable Capability (Sept 2017)
   ▪ AEMO submission to the Inquiry into modernising Australia’s electricity grid (Feb 2017)

4 Programs / working groups:
   ▪ ENA and AEMP Open Energy Networks
   ▪ AEMO VPP Demonstrations
   ▪ AER and ARENA Distributed Energy Integration program

5 Rule Changes:
   ▪ Register of Distributed Energy Resources (Aug 2018, rule made)
   ▪ Wholesale Demand Response Mechanism (Nov 2018, consultation)
   ▪ Advanced meter communications (Oct 2018, consultation)
   ▪ Enhancement to the Reliability and Emergency Reserve Trader (June 2018, consultation)
   ▪ Contestability of energy services (Dec 2016, rule made)
   ▪ Inertia Ancillary Service Market (Sept 2016, not successful)
   ▪ Non-scheduled generation and load in central dispatch (Aug 2017, not successful)
   ▪ Local Generation Network Credits (Dec 2016, not successful but rule made about DNSP publishing network information)
   ▪ Demand Response Mechanism and Ancillary Services Unbundling (Oct 2016, rule made)
### Section 8: Project description

#### Structure and intended operations of LTVM

| **Objective** | To demonstrate how local distributed energy resources and demand response can be incorporated into a local marketplace to improve the efficiency, security and resilience of the electricity grid and improve economic outcomes for participants. |
| **Marketplace Participants (Dairy Farms)** | Up to 200 dairy farms in the Latrobe Valley. The participating dairy farms will be a mix of both consumers and prosumers able to input generation, utilise demand response software or storage in the marketplace. Each dairy farm will have a tailored solution based on specific needs and demand profiles. Preliminary analysis of farms in the LTVM region indicates that the average farm is likely to support 80 kW solar and 250 kWh battery storage. Dairy farms have a fairly rigid energy consumption profile, with the capacity to sell excess energy during the day and potentially discharge from batteries. |
| **Virtual Microgrid Participants** | The LTVM entity will identify 100-150 residential energy customers and 10-20 commercial/industrial customers (likely to include some of the participating dairy farm co-operatives) willing to participate in a virtual microgrid (ie participants use existing network infrastructure and are not able to island from the grid) to trial local energy marketplace software for a minimum of 12-months. The microgrid will enable participants to buy and sell generation from distributed renewable energy resources, such as PV or batteries, be rewarded for their demand response capability (where it is requested by the network operator), and any grid stability services provided. |
| **Virtual Microgrid Technology** | **Microgrid application** The microgrid members will provide preferences and be able to respond dynamically using a mobile application (see Section 9 of “More Details”). The app will at a minimum allow for setting of price sensitivity, preferences for energy supply, and demand response capability of various devices for financial return. **Microgrid software** The microgrid will utilise blockchain technology to balance demand and supply and maximize load shifting. A TAG-e (hybrid meter/computer device developed to meet traditional hardware requirements for revenue grad utility meters) will apply smart contracts which will executed by reference to price and other user preferences. TAG-e controls those devices within its defined jurisdiction and securely communicates its decisions to other TAG-e devices via the blockchain network. There are two layers of functionality:  
  - a transactive layer enabling device-to-device energy trading transactions integrate data such as generating efficiency, carbon intensity and location-based pricing  
  - a control layer containing control logic linking the transactive layer and device outcomes. Control commands will be executed based on signals from the transactive layer via self-executing smart contracts. |
<table>
<thead>
<tr>
<th>Structure and intended operations of LTVM</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Corporate off-taker</strong></td>
</tr>
<tr>
<td>Discussions are underway with a potential corporate off-taker, interested in purchasing renewable energy from the LTVM as a means of achieving their internal emissions reduction priorities. This would potentially enable a floor price to be established within the LTVM, which would help mitigate price risk for LVTM members.</td>
</tr>
<tr>
<td><strong>Financing</strong></td>
</tr>
<tr>
<td>For dairy farms, the distributed renewable resources may be financed through Environmental Upgrade Agreements (EUA), being council-based financing mechanisms. Under a EUA, a lender provides finance to a building owner and the local council collects repayments through the rates system.</td>
</tr>
<tr>
<td><strong>Energy charges</strong></td>
</tr>
<tr>
<td>To qualify for avoided TuoS payments, a minimum of 5MW of solar would need to be installed in each local market place. The cost of providing the electricity transmission network is recovered from the Transmission Network Service Provider’ customers and is ultimately reflected in the bills end use customers pay. Avoided Transmission Use System payments are payments made to generators by the DNSP. These are paid where an embedded generator has reduced the TuoS charges the DNSP would otherwise have been obliged to pay to the TNSP.</td>
</tr>
</tbody>
</table>
Section 9: Application Functionality

Figure 1: Mobile app ability for customers to select their own power supply (indicative only)
Figure 2: Mobile app ability for users to see generation as well as select devices for demand response

Figure 3: Mobile app ability for users to see where energy is generated and add or suggest new distributed energy resources

Figure 4: Mobile app ability for users to see their profile, activities, and compete with other users

Figure 5: Mobile app ability to view historical energy information
A New Energy Future is on the horizon. New energy sources, smart technologies, industry fragmentation and empowered consumers are set to transform the industry. In this new and uncertain future where innovation is key, our new energy team helps start-ups, retailers, network service providers, regulators and other new entrants get creative. We understand the challenges and opportunities specific to the industry and we bring a team of experts to help you navigate the issues to achieve growth and success.

Multidisciplinary expertise

Drawing together expertise across projects, M&A, finance, regulatory, tax and intellectual property, we provide unique insights and valuable advice on new energy projects and transactions, including on:

- Blockchain and smart contracts
- Cloud-based technologies
- Regulatory, including prospective regulatory change
- Intellectual property
- Supply and licensing agreements

A transformation of the energy industry is inevitable and will require a shift in how energy markets function physically, commercially and legally. The questions that will define business decisions and policy prescriptions vary by industry and participant. Contact us to discuss your market strategy and explore the questions and issues you are facing as you adapt and position yourself ahead of this transformational change.

Contact us

SCOTT GARDNER
Partner
T +61 2 9236 2158
M +61 419 533 313
scott.gardner@au.kwm.com

Acknowledgements

Contributors: Odette Adams, James McGrath and Lauren Murphy

kwm.com

Asia Pacific | Europe | North America | Middle East

King & Wood Mallesons in Australia is a member firm of the King & Wood Mallesons network. See kwm.com for more information.
Latrobe Valley Microgrid Feasibility Study
Legal and regulatory recommendations and analysis
Prepared for LO3 Energy Pty Ltd

May 2019
Introduction

Residential energy consumers have traditionally been provided with 2 key services by the National Energy Market (NEM):

- stable energy prices: retailers protect the consumer from the volatility and complexity of the wholesale market by providing energy at stable prices
- stable network charges: networks supplying energy to consumers in a stable and reliable manner

However, the role of the energy consumer is evolving (and some might say this process has only just begun). Energy consumers now consume electricity they generate themselves, and electricity from the grid. They also actively engage with the NEM, providing excess generation, demand response and ancillary services (Active Consumers).

In contrast to traditional energy consumers, Active Consumers expect to be able to:

- sell excess generation: sell their excess generation, pooled through local or independent aggregators, to enable them to benefit financially from their solar units
- sell demand response: engage in demand management utilising automated and controllable systems to optimise their consumption and their energy costs
- sell ancillary services: provide market ancillary services, pooled through local or independent aggregators, to enable them to benefit financially from their solar units
- sell to and buy from their neighbours: sell to and buy from their neighbours through local or independent market operators, separately from the wholesale market (together, New Energy Services).

These services are not merely an extension of the current network and retail services – in many respects they are disruptive to the very business models of current network and retail service providers. To illustrate, traditional retailers sell electricity from the wholesale market to consumers, deriving profits from increased consumption, whereas demand management has the effect of decreasing consumption from the grid. Alternative service providers (New Energy Service Providers) have now entered the market with new offerings and business models to support and encourage the provision of these New Energy Services.

In response, regulators around the world, including the Australian Energy Market Commission (AEMC), are actively considering and implementing mechanisms that foster, enable and encourage New Energy Service Providers.¹ This report provides a number of recommendations in support of that long-term aim. We note that the AMEC is in the process of putting a “regulatory sandbox” mechanism in place. This mechanism may be a suitable environment in which to further test and explore these recommendations.²

Purpose and nature of this report

This report is written from the perspective of New Energy Service Providers.

We have been asked to consider the obstacles and challenges posed by the current regulatory and legal frameworks in Australia to the adoption, rise and success of New Energy Services, and make recommendations within that context. Our recommendations do not consider or have regard to the economic or other commercial costs or impacts they may have on other industry stakeholders. This is beyond the scope of this report.

Recommendations

To facilitate the role of New Energy Service Providers, we recommend consideration be given to further regulatory change in the following areas:

¹ See Section 7 of "More Details" for an extensive list of Australian reports, reviews and programs that have focused on this topic.
² AEMC, Regulatory Sandbox Proposal (07 March 2019)
Retail market: encourage new market participants with innovative business models in the retail market:

- **Recommendation #1**: Establish a new Market Participant classification for New Energy Service Providers. This will allow New Energy Service Providers to supply demand management, sell aggregated generation to the grid and facilitate peer-to-peer trading

  This recommendation is consistent with the AEMC’s recommendations in the Reliability Frameworks Review, which recognises the need to define the role of New Energy Service Providers.

  We also recommend that the rules be extended beyond the recent rule changes that established “Market Small Generation Aggregator” and “Market Ancillary Service Providers” so as to give the Australian Energy Market Operator (AEMO) flexibility and optionality in categorising new Market Participants, to enable the categories to keep pace with the changing nature of New Energy Service Providers.

- **Recommendation #2**: Allow consumers to contract with multiple service providers at the same connection point

  This recommendation, to allow multiple trading relationships at the same connection point, is also consistent with the AEMC’s recommendations in the Reliability Frameworks Review. We also endorse the AEMC’s suggestion that methods should be developed for sharing financial responsibility and customer protections amongst all service providers at a single connection point.

Energy market design: allow consumers to trade energy, demand response and ancillary services in the wholesale market:

- **Recommendation #3**: Demand response mechanism established to allow New Energy Service Providers to bid demand response into the wholesale electricity market

  Endorsing the recent demand response rule changes, we recommend that a demand management mechanism be established and that demand response aggregators be treated on equal footing to generators. We also recommend further consideration be given to potential options that would enable greater use of non-firm demand response.

- **Recommendation #4**: Increase engagement and access to ancillary support markets

  We endorse the AEMC’s recommendation in the Frequency Control Framework Review that the existing rules relating to Market Ancillary Service Providers and Small Generation Aggregators be amended so as to allow New Energy Service Providers equal access to the FCAS market.

Distribution System and Market Operators: manage markets and physical assets to ensure supply and demand are balanced:

- **Recommendation #5**: Establish and provide support for Distribution System and Market Operators (DSMOs) to oversee mechanisms for control and trading of New Energy Services, including demand response, aggregated generation and peer-to-peer

  We recommend that independent Distribution System and Market Operators be established to provide support for and co-ordination of the services to be provided by New Energy Service Providers.

- **Recommendation #6**: Facilitate data access and sharing between Market Participants, while maintaining privacy and confidentiality protections

  In addition to establishing independent Distribution System and Market Operators, current energy data requirements should be updated to reflect the changing nature of the energy market and distribution system. We recommend that a data sharing framework be implemented and managed by AEMO, supported by independent Distribution System and Market Operators.

- **Recommendation #7**: Mandate cooperation between traditional Market Participants and New Energy Service Providers and establish appropriate dispute resolution mechanisms, including establishing rules and procedures for financial licencing, billing, data exchange and security
As the distribution network and associated markets become more complex, co-operation between market participants (particularly those at the same connection point) will become increasingly necessary. We recommend that consideration be given to Distribution System and Market Operators being charged with the role of not only managing co-operation but also overseeing potential disputes between market participants.

**Distribution Network**: ensure that the network (and its pricing model) caters to and facilitates bi-directional energy flows:

- **Recommendation #8**: Enhance and maintain the visibility of and the data available on the component parts of the distribution network

  Increasing data sharing among Market Participants is beneficial (as set out in recommendation #7) however the availability of adequate distribution network data is also required to ensure all Market Participants are able to assess the true cost and value of electricity services. We recommend that distribution networks are incentivised to increase the collection of data to provide all market participants better visibility of the component parts of the distribution network. This will provide New Energy Service Providers information which will enable them to target their services so as to avoid or mitigate grid augmentation requirements and costs.

- **Recommendation #9**: Mandate opt-out cost-reflective pricing for networks and remove structural barriers for uptake of cost-reflective pricing

  The AEMC has already enacted significant rule changes to network pricing in this regard, however there has been limited take up to date of AEMC’s new model of network pricing. We recommend that cost-reflective pricing is opt-out (rather than opt-in as it is currently) and that the State legislation that creates structural barriers to the uptake of locational based pricing be removed or amended.

- **Recommendation #10**: Require networks to engage in good faith negotiations with New Energy Service Providers regarding network charging

  Cost-reflective pricing (as above) is a positive step forward for Active Consumers, however there are many other alternative pricing models that may provide better outcomes (particularly for those involved in peer-to-peer trading). We recommend that, similar to the negotiated connection regime in Chapter 5, distribution networks be required to negotiate with peer-to-peer service providers regarding network charging when benefits (such as grid augmentation avoidance) can be evidenced.

- **Recommendation #11**: Better integrate renewables by investing in and managing the grid so as to avoid zero export

  The EU has recently implemented a right for all consumers to connect and export electricity to the grid. We suggest that Chapter 5A be amended to ensure that networks are required to support solar connection and export (beyond requiring individual customers to pay for grid augmentation). We acknowledge, in saying this, that the costs of this will need to be carefully balanced against the benefits they will deliver to the consumer.
Contents

Retail Market – roles, responsibilities and restrictions
Retail Market – Current state of play Page 1
Retail Market – Recommendations Page 2

Market Design – mechanisms, markets and contractual frameworks
Market Design – Current state of play Page 8
Market Design – Recommendations Page 9

Distribution Market and System Operator – control and co-ordination
Distribution Market and System Operator – Current state of play Page 12
Distribution Market and System Operator – Recommendations Page 13

Distribution Network – visibility, access and pricing
Distribution Network – Current state of play Page 16
Distribution Network – Recommendations Page 17

More details
Section 1: Current retail framework Page 21
Section 2: Multiple Trading Relationships – rule change attempts Page 24
Section 3: Energy data access Page 25
Section 4: Access Model Page 26
Section 5: DER coordination challenge Page 27
Section 6: Network pricing Page 28
Section 7: Regulatory reform and government reviews Page 30
Section 8: Project description Page 31
Section 9: Application Functionality Page 33
Current state of play

Under the National Energy Retail Law (NERL), the seller of electricity to a premises is required to be an authorised retailer or an exempt retailer. Further, under the National Energy Rules (NER), each connection point must be associated with one metering installation with its own National Meter Identifier (NMI) and one Financially Responsible Market Participant (FRMP).

The practical effect of this regulatory model is that all customers must have a retailer for supply from the market and if a consumer wishes to sell electricity to the grid, the consumer must in practice use the same entity they use to purchase electricity. That is, consumers must in practice sell electricity to the grid through their retailer. The only other alternative is to install a second connection point and to sell through a Small Generation Aggregator. This Small Generation Aggregator approach restricts the ability of New Energy Service Providers in the following ways:

- there must be two separate meters, one for the load and one for the generation (PV or battery storage)
- the meter that the SGA is responsible for must be export only
- the SGA is not able to provide ancillary services

If there is only one connection point and it will be used to import electricity (which will almost invariably be the case), New Energy Service Providers must have a retail licence, a retail licence exemption or partner with a retailer to utilise their retail licence (and an SGA will also require a retail licence (ie because electricity is also being imported through that connection point)). This is not without reason however, as retailers provide significant price protection for customers including, importantly, price stability.

See Section 1 of “More Details” for options available to New Energy Service Providers under the current regulatory model (including exemptions currently utilised by embedded networks) and why, in their current form, they are not conducive to the success of New Energy Service Providers.

Recommendations

Recommendation #1

Establish a new Market Participant classification for New Energy Service Providers. This will allow New Energy Service Providers to supply demand management, sell aggregated generation to the grid and facilitate peer-to-peer trading

Acknowledging that there is a distinct difference in the roles played by traditional energy Market Participants (eg retailers, networks and service providers and the market operator (ie AEMO)) and those played by New Energy Service Providers, leads to the logical conclusion that if New Energy Service

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3 Section 88, National Energy Retail Law.
4 Section 2.3A.1, National Electricity Rules
Providers are to enter the market at scale, regulation will need to define the role and responsibilities of New Energy Service Providers as new Market Participants.

The AEMC has been proactive in creating alternative Market Participant regimes for New Energy Service Providers. Examples include:

- Market Ancillary Service Provider, introduced in November 2016. Market Ancillary Service Providers have the ability to provide FCAS Services through individual or an aggregation of market loads without the requirement to register as a Market Customer (ie an entity that purchases electricity from the spot market).\(^5\)

- Small Generation Aggregator, a registered participant which may supply electricity aggregated from one or more small generating units to a transmission or distribution system. Small Generation Aggregators must be Market Participants (not non-market) however can be semi-scheduled. Small Generation Aggregators must sell all sent out generation to the spot market and purchase (if required) all electricity supplied through the national grid to the market connection point.\(^6\) SGAs must also be the financially responsible participant at the connection point.\(^7\)

- Proposed Demand Response Service Provider. According to AEMC this participant would be the only participant class able to sell demand response into the wholesale market through the demand response mechanism. Demand Response Service Providers would need to register with AEMO and also need to classify their loads as ‘demand response loads’. AEMC also goes further in supporting this new Market Participant by recommending that retailers would be prohibited from opting-out of it on behalf of their customers. That is, retailer participation in the demand response mechanism would be mandatory.\(^8\)

This recommendation aims to further progress the AEMC work in creating a separate classification for New Energy Service Providers by establishing a standardised new Market Participant classification. It is expected that this recommendation will go beyond the exemption framework (that is predominately used for embedded networks and set out in Section 1 of “More Details”) and instead amend the rules to include a ‘gateway’ definition of new Market Participant. Further to this recommendation, we would also expect:

- that AEMO (in consultation with the AEMC) would be given flexibility and optionality in defining the conditions and classifications of each New Market Participant (registered under that classification) to enable the market classifications to keep pace with the changing nature of New Energy Service Providers

- that AEMO would be required to actively review new Market Participant registrations regularly to ensure all energy services are adequately and appropriately classified

- AEMO would establish guidelines that:
  - set out the appropriate licencing regime for New Energy Service Providers, acknowledging that a demand response provider will likely have different licencing requirements to a local energy market operator due to their different risk profiles
  - redefine the responsibilities for each party at a given connection point (ie who will be responsible for operation, bidding, network losses, settlement and prudential arrangements - see Recommendation #2 for more detail with respect to redefining the FRMP)

- the existing rules to be updated to ensure/mandate:

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\(^5\) AEMC, *Demand Response Mechanism and Ancillary Services Unbundling* Rule Change (5 November 2015)

\(^6\) Section 2.3A.1(h), *National Electricity Rules* – note that if there are two connection points a Small Generation Aggregator may not be required to purchase electricity at the second connection point if a Retailer is supplying electricity at the other connection point. This is also the case for child meters in an embedded network.

\(^7\) AEMO, *SGA Factsheet*

- information sharing among all Market Participants, on a need-to-know basis (see section 3 below)
- that new Market Participants are registered without the need to be or to partner with traditional Market Participants (and as such are independent service providers)
- that consideration would be given to the suitability of generator classifications. For example it may be appropriate to amend the classification of non-scheduled generation so that both retailers and new Market Participants can register, however limits may also need to be imposed on:
  - the number of customers that a new Market Participant can have (ie aggregate nameplate of customers) within particular regions
  - the protections (in particular the disconnection protocols) that are to apply to the connection points that have multiple trading relationships (see Recommendation #2, discussion on limits to multiple trading relationships for more details)
- that the NERL be re-framed to include New Energy Service Providers (in addition to Retailers) while also updating the consumer protections and the roles and responsibilities that are currently set out in the NERL to reflect the new inclusion of New Energy Service Providers (as appropriate) (see Recommendation #2 for more details)

Recommendation #2:
Allow consumers to contract with multiple service providers at the same connection point

We support the AEMC recommendation in the Reliability Frameworks Review that a rule change be implemented to allow multiple trading relationships at the same connection point. This recommendation would give Active Consumers the right to contract (independently) with multiple service providers at the same connection point. Practically, this recommendation would mean that each connection point would be entitled to have multiple service providers, each with their own NMI, interacting with the wholesale market on their behalf.

The AEMC illustration sets out how multiple trading relationships could be implemented:
To implement multiple trading relationships, we endorse the AEMC’s recommendations in their Feasibility Review. The AEMC suggests the following key regulatory changes:

- **sharing of financial responsibility**: remove the requirement that there must only be one Financially Responsible Market Participant at a connection point. Instead, implement a new regime for the sharing of these responsibilities between all service providers (as appropriate).\(^9\)

- **settlement and billing**: consideration be given to updating settlement and billing regulation and procedures to accommodate multiple trading relationships.

The UK is considering a code change “P379: Enabling consumers to buy and sell electricity from/to multiple providers through Meter Splitting”.\(^10\) Unlike Australia, the UK already allows for dual metering under the SVA Shared Metering Arrangement, whereby co-owners of generation assets at large non-domestic sites can split export volumes by bilateral agreement. This proposal aims to extend meter splitting to multiple independent trading parties at domestic sites to facilitate new energy services.\(^11\)

The proposal suggests the following:

- customers would be able to engage multiple (not just two) trading partners at one meter and split the volumes between the trading partners

- the customers would have a ‘main’ or ‘default’ supplier (similar to the concept of retailer of last resort in the NER) responsible for metering and data collection/aggregation

- the customer would also have a new Party Agency called the Customer Notification Agent (CNA) that is responsible for reconciling flows through a Settlement Meter and notifying adjustments to metered volumes to reflect volumes attributed to additional Suppliers\(^12\)

As there would no longer be a bilateral agreement between the trading parties under this new proposal, roles and responsibilities (including in relation to connection and disconnection) would require a greater level of independent oversight and coordination.

The UK model is still in a consultation phase. Key issues being work-shopped include:

- how the roles and responsibilities of the ‘Supplier’ will be split between multiple parties

- how the disputes process will accommodate multiple trading parties

- who would step-in to take on the new responsibilities of CNAs- it has been suggested the DCC and Data Controller roles may be extended\(^13\)

We recommend that Australia continues to follow the developments in the UK while recognising the different nature of the Australian energy market.

- **alternative metering and settlement**: allow for alternative metering arrangements, such as subtractive metering. The AEMC notes that it is important that the rules do not ‘bake in’ a particular metering arrangement but instead allow for optionality and flexibility as new metering arrangements will no doubt arise after the adoption of multiple trading relationships. This recommendation would also require a change to the current metering coordination rules so as to require exchange of information between relevant parties.

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\(^10\) P379 “Multiple Suppliers through Meter Splitting”, (8 February 2019) Elexon website

\(^11\) Note that Elexon (the change proponent) sees P379 as a tactical change that can be delivered in shorter timeframes than the more extensive changes that are expected to arise out of the Ofgem Future Supply Market Arrangements review. The learnings of this change could then be used to inform the tactical changes of the Ofgem project. See Elexon Webinar, 12 minutes

\(^12\) Cornwall Insights P379 Workgroup presentation slides, slide 12

\(^13\) Elexon P379 Meeting 1 Summary, page 3
One possible alternative metering arrangement could be blockchain based sub-metering. Developed by a Netherlands metering operator (Enexis) in conjunction with IBM, in response to upcoming legislation that will enable multiple trading relationships, it acts as an alternative for multiple smart meter setups. Large energy consuming IoT appliances (eg pool pumps and air-conditioners) will record their energy on the blockchain and provide the sub-metering data to the smart meter. Enexis, the meter operator, will then create billing determinant data based on the smart meter reads in combination with the blockchain. On a business level this means that concurrent energy delivery by multiple retailers can be facilitated (eg a different retailer to charge your EV vs power the home).

- **de-energisation and disconnection**: update the NERL so as to replace ‘connection point’ with ‘NMI’ so that each NMI is treated as a separate ‘premises’ for the purposes of the NERL. This would allow each service provider to disconnect and reconnect its individual load, independently of another service provider’s portion of the customer load.

The AEMC suggests that the rule change only allows for multiple trading relationships where separate disconnection of each settlement point is possible. While this seems logical, it may have the practical effect of limiting the availability of multiple trading relationships. An alternative option could include creating a ‘waterfall’ approach to disconnection so that a baseline of basic energy services is always required to be offered and all FRMPs are to share the respective costs (this is similar to the large customer regime whereby the retailer is given a right to charge if they are the FRMP for a customer where no contract is in place).

This waterfall approach is also reflected in the UK proposal described above - customers have a ‘main’ or ‘default’ supplier (similar to the concept of retailer of last resort in the NER) responsible for metering and data collection / aggregation. It is likely that this ‘main’ supplier would also be responsible for connection and disconnection.

- **customer protection**: the potential need for ‘qualifying criteria’ for customers who want to engage multiple service providers. Some suggested qualifications include:
  - only allowing large customers to engage multiple service providers
  - requiring each service provider to be able to disconnect and reconnect its individual load independently of the other service providers’ proportions of the customer’s load

While we respect and acknowledge that New Energy Services are not suitable for all customers, we suggest that further consideration be given to restricting the benefit of this rule change to only large customers. Limiting the application of multiple trading relationships to large customers only would narrow the range of people who could potentially benefit from such a rule change. As a starting point we suggest looking to alternative safeguards:

- hardship and life support customers be expressly excluded
- consumer protection safeguards under the NERL, NERR and Retail Code (as relevant) be amended so as to apply to and be relevant to new Market Participants (as above), in particular ensuring that Active Customers provide clear and active consent and are made aware of the higher level of risk associated with alternative energy service providers
- regulatory authorities should monitor systematically the above consumer protection safeguards, including whether offers from aggregators are adequate for residential electricity consumers or if the financial risk is too high for certain consumer groups. This analysis should include whether consumers receive clear, relevant and complete information to

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14 Master thesis: Blockchain Technology in the Energy Transition, pages 114 and 122
15 Master thesis: Blockchain Technology in the Energy Transition, pages 114 and 122
16 See full consultation media release by the ACM for more details on the multiple trading relationships rule change in the Netherlands
17 AEMC, Reliability Frameworks Review Final Report (26 July 2018), page 155
accurately assess the risks and opportunities of entering into aggregation contracts and how consumer data is protected. A potential format for this could be AEMO’s yearly retail market review. Regulations should ensure that the regulator has the power to introduce additional protections as an expedited rule change if the monitoring indicates that revision is needed.

With this in mind, it is also important to recognise that the new Market Participant definitions will act as a ‘limit’ to the services that can be provided to individual customers (see Recommendation #1 above).

We can also look to international examples when considering regulatory change in Australia. These include:

**Netherlands and Belgium**

- Recently, the Netherlands implemented a code change to facilitate multiple trading relationships.\(^{18}\) The rule change came out of the Pantheon project, which researched changes to the Netherlands wholesale electricity market model to future-proof the market in the context of the current energy transition. The Netherlands’ Electricity Act 1998 did not explicitly prohibit multiple trading relationships, however there were several articles in the legislation that implied that there would be only one licenced supplier for each connection point. The code change started first with large scale commercial consumption connections and then extended the solution to small customer connections.\(^ {19}\)

- It is clear that this rule change has created a dynamic environment for peer-to-peer and aggregator business models to expand, including Vandebron and Powerpeers.

- New legislation in Belgium addressing the role of aggregators and independent aggregation will soon be in place, following the Netherlands model – the central tenant of which is providing equal footing for all market actors.\(^ {20}\)

**UK**

- A similar code change to the Netherlands has been proposed by Elexon in the UK. Importantly, the UK already has a concept of multiple service providers for large energy customers. The new code change extends this concept to residential prosumers. Elexon sets out a number of examples of the roles able to be played by multiple service providers, including:

  - Community energy schemes where a generator, such as a battery or photovoltaic (PV) cells, is owned communally and its export shared between members.

  - Electric vehicle (EV) manufacturers offering vehicles on a simple £/mile basis, including all the electricity needed to charge the vehicle (this could be at multiple charging points at different locations, subject to technology solutions to support appropriate measurement at the various locations). This could also apply to future ‘device as a service’ markets for household appliances in ‘smarter homes’ (for example, fridge rental with power included).

  - Peer-to-peer trading. For example, a customer buying a neighbour’s excess solar energy. This could be facilitated by the development of apps that allow consumers with micro-generation to sell (or give) their excess generation to other nearby consumers (rather than receiving the export feed-in tariff). For example, an app could be designed that allowed consumers to donate their ‘spill’ to local charities, or families in fuel poverty.

  - ‘Rapid switching’. Energy is purchased from different suppliers or wholesale energy sources for periods as short as a Settlement Period (Half Hour).

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\(^ {18}\) Verdict CBb case Anexo ‘multiple suppliers on a connection’ – judicial decision 6 Dec 2018 – The Trade and Industry Appeals Tribunal ruled in December 2018 that Anexo’s challenge to ACM’s decision to change the code was inadmissible. The code changes were allowed to proceed and became law in 2018.

\(^ {19}\) Code decision facilitating multiple supplies on a connection (18 July 2017)

\(^ {20}\) SEDC *Explicit Demand Response in Europe – Mapping the Market* 2017, page 10
To facilitate this, the code change will require the creation of a new Part Agent role, the “Customer Notification Agent” (CNA). The CNA’s role would be to:

- notify BSC Central Systems of the Metering Systems for the consumers, generators and suppliers involved in energy trades or reallocations under the relevant scheme
- notify the associated energy volumes and ensure consistency with the existing contract notification regime
- notify adjustments to metered volumes to reflect volumes to be attributed to additional Suppliers.

The code change is still in its consultation phase, however is set to be implemented by April 2020.

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21 P379 proposal ‘Multiple Suppliers through Meter Splitting’, (8 February 2019) Elexon website
Current state of play

The National Electricity Market (NEM) is an energy-only, gross pool market with real-time (5-minute) scheduling and eight FCAS spot markets. The NEM is designed to send legitimate price signals to market participants so that supply and demand are in balance and the grid operates at a frequency range as close to 50 Hertz as possible.

To do this, AEMO would traditionally rely on both the NEM and FCAS markets to:

- balance the NEM demand and supply – by dispatching generation (every 5 minutes) to exactly meet forecast demand
- procure frequency control ancillary services (FCAS) - by contracting with generators that are able to increase or decrease output on direction.

At the time the NEM was designed, large, scheduled, centralised generators (coal, gas and hydro) supplied almost all electricity and FCAS. Other energy support services (such as physical inertia, system strength and voltage control) were essentially ‘bundled’ in with the cost of supply as they were inherent to centralised generators - there was no need to value them or incentivise generators to provide them.

However, in the last decade the NEM has seen the rapid rise of intermittent generation (including the penetration of distributed renewable sources) alongside the closure of many centralised generators. This is problematic for AEMO’s above approach as:

- intermittent generation (ie wind and PV) is non-dispatchable and their short-run operating costs are essentially zero. As such, intermittent generation typically bids into the NEM at zero to ensure that it is called on to generate. As such, intermittent generation does not respond to traditional market price signals and is thus problematic for balancing long term demand and supply
- intermittent generation is non-synchronous and non-dispatchable, meaning it does not provide the inherent support services we typically take for granted from centralised generation and also struggle (without paired technologies such as battery storage and flywheels) to provide FCAS, as they are unable to be scheduled (ie FCAS on-demand).

The AEMC is of the view that the NEM design requires adjustment to account for this shift and is taking active steps towards reforming market mechanisms so as to put in place the correct price signals and incentives to support the new energy mix. Similarly, in an advice to the Commonwealth Government, AEMO stated that "without extensions to the current market design, it cannot provide adequate and sustainable price signals to either maintain dispatchable capability or incentivise new development at the level necessary to maintain system reliability."\(^{22}\)

It is clear that the AEMC has recognised that the valuing of all services (and arguably not just energy only) is crucial to ensure that the full value of services to the system is accounted for and that the correct investment incentives are in place. However, there are a still a number of barriers that prevent New Energy Service Providers (and therefore Active Consumers) from engaging and responding to price signals in the NEM and FCAS markets. For example:

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\(^{22}\) AEMO, Advice to Commonwealth Government on Dispatchable Capability (September 2017)
• demand management: under the current regulatory regime demand response is contracted directly between retailers and customers (and not, for example, on a central traded platform like the ASX).

• ancillary services: under the Market Ancillary Service Specification (MASS) all FCAS providers can only register a minimum amount of 1MW and must use high speed meters.

• feed-in tariffs: under the current framework, scarcity pricing promotes maximum self-consumption so as to avoid the costs of paying for retail provided energy. Flat tariff structures (and no tariffs for export of electricity) distort the cost of electricity and the benefits of electricity generation, particularly at a local or community level. Active Customers are encouraged by the current market mechanisms to consume their own generation – rather than demand managing and supplying excess generation to the NEM (at a lower cost to the system and retailers than central generation).

While mechanisms such as demand response and the FCAS markets have evolved to encourage greater participation and valuing of energy support services, these markets still require significant adjustment to ensure that New Energy Service Providers are encouraged and enabled to participate.

Recommendations

The Oxford Institute for Energy Studies states that the NEM and associated policy must accommodate not only energy, but a range of new and existing services that help to create wholesale real-time economic signals for the complex mix of services that are required for the comprehensive operation of a modern electricity network.

We recommend that AEMC continue its work in establishing new mechanisms, markets and contractual frameworks required to support NESPs.

Recommendation #3:
Demand response mechanism established to allow New Energy Service Providers to bid demand response into the wholesale electricity market

We support the AEMC recommendation that demand response providers be treated on equal footing to generators in the wholesale market, enabling them to more readily offer wholesale demand response in a transparent manner (rather than in traditional bilateral off-market contractual relationship).

There are currently a number of rule change requests that seek to facilitate wholesale demand response in the NEM:

• wholesale demand response mechanism - a mechanism that would allow third parties to offer demand response into the wholesale electricity market in a transparent, scheduled manner

• wholesale demand response register mechanism - a proposal that would introduce an obligation for retailers to negotiate in good faith with third parties looking to provide wholesale demand response through a register

There are a number of costs and questions that require further consideration including:

• determining a methodology for evidencing demand response and in particular defining an appropriate baseline (so as to not allow consumers to “game” the system by increasing energy consumption before forecasted peaks)

• the impact on other participants and consumers

• costs associated with system changes, including to AEMO’s settlement systems

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23 AEMC, Wholesale Demand Response Mechanism Rule Change

24 AEMC, Wholesale Demand Response Register Mechanism Rule Change
▪ calculation or evidencing deferred investment costs and providing compensation / rewarding participants appropriately

▪ costs of installing “smart” technology and changing systems to schedule the demand response.25

Further, the legal responsibilities of a New Energy Service Provider (as opposed to a Retailer) raise numerous questions, including:

▪ whether the demand response contracts (or offers) would constitute a financial product and if so if demand response providers would be required to hold appropriate licencing

▪ ensuring consumer protections are maintained – particularly with respect to the control of intelligent devices

We can also look to international examples when considering regulatory change in Australia.

▪ The EU has acknowledged the benefits of demand response for flexibility in energy markets, proposing the following “recast” to Article 17 (Demand Response):

  Member States must:

  ▪ encourage customers, including those offering demand response through aggregators, to participate alongside generators in a non-discriminatory manner in all organised markets

  ▪ ensure that networks, when procuring ancillary services, treat demand response providers, including independent aggregators, in a non-discriminatory manner on the basis of their technical capabilities.26

▪ Smart Energy Demand Coalition’s Explicit Demand Response in Europe – Mapping the Market 2017 report provides an extensive profile of Member State’s implementation of Demand Response. The below map illustrates each Member State’s demand response development

![Map of European Member States](image)

▪ The Member States will no doubt look to France as a model for implementing the new Article 17. The French model (known as the NEBEF mechanism) is one of the most advanced demand response mechanism in the EU.

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26 EU Legislation Briefing, Common rules for the internal electricity market
27 SEDC, *Explicit Demand Response in Europe – Mapping the Market 2017*, for France’s NEBEF mechanism see page 11
C&I customers have had access to demand response (both in wholesale and capacity markets) since 2017 and France is currently exploring way to integrate residential resources to harness distributed energy resources for demand response.\(^{28}\)

Importantly for the Australian context (particularly as an energy only market), the NEBEF mechanism enables independent aggregators to perform load reduction without having to obtain permission from retailers and from a network point of view, reducing load is seen as the equivalent of producing energy. This principle is also reflected in the wholesale market bidding structure.\(^{29}\)

**Recommendation #4:**

*Increase engagement and access to ancillary support markets and encourage further consideration of new support markets (if required)*

We endorse the AEMC’s recommendations in the *Frequency Control Framework Review* that the existing rules relating to Market Ancillary Service Providers and Small Generation Aggregators be amended so as to allow New Energy Service Providers equal access to the FCAS market.

The Australian FCAS markets have historically attracted participation by synchronous generation (such as hydro, coal-fired and gas-fired generation). However, with the rise of distributed energy resources and the simultaneous withdrawal of synchronous generation it is clear that the level of FCAS will need to be supplemented by other sources. This is an opportunity for New Energy Service Providers.

AEMC has recommended in their Frequency Control Frameworks Review that the existing rules be amended to clarify that:

- Market Ancillary Service Providers are able to offer market ancillary services
- Small Generation Aggregators be enabled to offer market ancillary services

However, AEMC also recognises that there are technical challenges that will arise from allowing such participation. FACS via a large fleet of aggregated resources may have localised network impacts (eg voltage) or may negatively impact power system security. This issue was also identified in the EU. As a solution the EU proposed that where system impact could be identified and evidenced, aggregators may be required to pay compensation for system damage.

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\(^{28}\) SEDC, *Explicit Demand Response in Europe – Mapping the Market 2017*, for France’s NEBEF mechanism see page 81

\(^{29}\) Deloitte, *Reaching the optimum: for monopoly to aggregators*, page 17
Current state of play

AEMO is responsible for balancing supply and demand and ensuring the secure and reliable operation of the network. Importantly, as an independent market operator AEMO is technology neutral, and primarily focused on ensuring the resources available to it meet the demands of the system at the time and location necessary.

To fulfil this role, AEMO requires:

- **Appropriate mechanisms for trading generation and support services**
  Currently, AEMO utilises reverse auction dispatch bidding and direct contracting of non-market ancillary services. Traditional generators are (for the most part) dispatchable. As such, AEMO’s most appropriate mechanism for generation and support services has traditionally been centralised dispatch. AEMO relies on the NEM dispatch engine software that operates in accordance with the Power System Operating Procedures. The NEMDE co-opts with the FCAS market so as to issue dispatch instructions (electronically via the automatic generation control system (AGC) or the AEMO Electricity Market Management System (EMMS) interfaces).[^30]

- **Sharing and access to data to inform demand forecasting**
  Under the current regulatory regime, AEMO has (or will soon have) access to data for three fundamental functions:
  - forecasting demand - the data required for this function includes the data on the Distributed Energy Resources Register NMI Standing Data and accurate weather data
  - dispatch and global settlement - the data required for this function includes forecast interconnector flows, constraints, regional reference price, demand, dispatchable generation, dispatchable load, and ancillary services data
  - providing information to the market - AEMO operates the e-hub for transactions between market participants and systems for participants to share information within the market

  For more information about the current access arrangements to energy data see Section 3 of “More Details”.

- **Market co-ordination among all market participants**
  Currently, co-ordination between NEM market participants is relative simple as there is only one market participant per connection. However, with the potential for multiple FRMPs at any one connection point and the sharing of responsibilities, the requirement for co-operation of multiple service providers will be essential.

[^30]: AEMO, *Advice to Commonwealth Government on Dispatchable Capability* (September 2017), page 2
Recommendations

Recommendation #5:
Establish and provide support for Distribution System and Market Operators (DSMOs) to oversee mechanisms for control and trading of New Energy Services, including demand response, aggregated generation and peer-to-peer.

Previously, grid control services and generation could be procured (and subsequently dispatched) from centralised generation on a relatively equivalent basis. However, now the role of a market operator in allocating and dispatching resources to achieve balance is resoundingly complex. This is because the functional capacities of distributed energy resources are not equal (see Section 4 of “More Details”).

Drawing on the extensive work AEMO and Energy Networks Australia have conducted as part of their Open Energy Networks consultation, we recommend that Distribution System and Market Operators (DSMOs) be established to oversee mechanisms for control and trading of New Energy Services at the distribution market level (including demand response, aggregated generation and peer-to-peer).31 This role, similar to AEMO’s role, will be responsible for:

- distribution system operations (ie safe, reliable and efficient operation of a local distribution system)
- distribution market operations (ie operation and management of a market platform to ensure that all participants meet registration requirements, information transparency, dispatch reconciliation and market settlement)

The DSMO, which may be an independently run marketplace / platform or a combination of multiple service providers (ie networks, energy management providers, platform providers and aggregators) working together to create a marketplace / platform will be required to interact with AEMO for centralised dispatch.

However, consistent with many submissions to the Open Energy Networks consultation we believe that the DSMO model should not be ‘picked’ at this time. Instead, we recommend a staged approach – whereby AEMO continues to act as the whole of market operator and by doing so co-ordinates and directs the framework for distribution system operation.

This means that AEMO will play a vital role in developing and implementing the framework for how the new distribution system is managed and operated. This is important as it allows AEMO to leverage off its experience as an operator and ensure that the framework remains independent of any market participant bias. Having a staged approach will ensure that we do not stifle innovation and competition among platform providers or hard-wire in the ‘wrong’ approach. In time, we acknowledge that this system / management role may be localised so as to lend itself to independent operators that have developed platforms suitable for distribution operation management at local levels (such as LO3’s Exergy and GreenSync’s Decentralised Energy Exchange platform).

We understand that the OpEN team is working to develop models on how co-ordination can be achieved based on the view that incremental (or staged) changes are required. We also acknowledge and support the team’s view that while incremental changes are the goal, first they need to look at developing a ‘future framework’ so as to ensure that the changes are not “piecemeal, rendering the industry incapacitated at a future point in time when redesign will be difficult”.32

In taking a staged approach to the establishment of a DSMOs, we recommend that:

- all changes are designed to ensure flexibility, so that they are easily changed, adapted and modified to evolving market conditions

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31 Energy Networks Australia, “Are we there yet?” article by John Phillpotts and Ryan Wavish (28 September 2017)
32 Open Energy Networks, Consultation Response, pages 18 and 20
AEMO, as the current market operator, is supported in keeping pace with change (including funding for IT system upgrades and development of new platforms)

AEMO (and other New Energy Service Providers in the platform development space) be encouraged to develop and apply standards protocols (including APIs, open source code and communication) to ensure that, even during transition, any changes are focused on accommodating New Energy Services.

As a starting point, we recommend establishing frameworks for co-ordination and dispatch arrangements. This would include determining the appropriate scheduling and dispatch requirements to attempt to account for (currently invisible) behind the meter controllable loads in central dispatch or alternatively, co-optimised load and demand models.

Recommendation #6:
Facilitate data access and sharing between Market Participants, while maintaining privacy and confidentiality protections

The volume of data being generated, processed and stored has been increasing and will continue to do so as the energy market responds to the rise of smart metering and real time settlement and distributed energy generation. As the market moves towards further storage and generation of distributed energy, greater visibility of the distribution system (including at and behind every connection point) will be needed, particularly as AEMO seeks to maintain network stability and ensure balance of supply and demand.

To increase access to and use of relevant data we recommend that the following be considered:

- **data access and availability** – there are a number of datasets that will be required to ensure New Energy Service Providers are able to provide their services. The Consumer Data Right sets out a number of datasets that are considered relevant to consumers (see Section 3 of “More Details”). Equally these datasets are crucial for New Energy Service Providers to be able to provide customers with new and competitive services.

- The ACCC’s recent consultation paper titled “Consumer Data Right in Energy” explores the access model appropriate for energy data (summarised in Section 4 of “More Details”).

- We recommend that regulators and industry look to experiences overseas when considering what access model to adopt. The Netherlands is an interesting framework for Australia to consider, particularly as the Dutch have a similarly high penetration of distributed renewables and significant system balancing challenges. In 2007, the Dutch set up EDSN as a “central data hub”. EDSN currently provides the following services:

  - customer portal giving customers control over their own data
  - central service to store and exchange data on both centralised and distributed power-generating facilities in the Netherlands for all market participants
  - centralised and uniform allocation and reconciliation processes that allow distributed energy resources to interface with the wholesale market

In this way, we encourage policy reform in the data space to look beyond the current use cases for energy data (such as comparison sites and customer switching) and towards the future data use cases, including in particular using residential energy data to co-ordinate, control and interface with the wholesale market.

- **data governance and privacy** – security, privacy and governance of data sharing needs to be considered and thoughtfully addressed. Distributed energy raises concerns as data can potentially

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33 ACCC, *Consultation paper on energy data access models* (25 February 2019)
include personally identifiable information from NMI, household consumption patterns and customer billing information.

We understand that the ACCC Consumer Data Right in energy will further explore the role of data governance and privacy in relation to data sharing. We strongly encourage privacy by design principles and further technical measures to protect privacy and data governance, be integrated into any data sharing regime.\(^{34}\)

- **communications infrastructure and standards** – in general, distributed energy resources are smaller and more geographically diverse than traditional power plants. In order to extract value from distributed energy resources, both as a service and for grid flexibility, communication infrastructure is essential. The system must also be sufficiently robust to resist cyber-attacks, provide system stability and reliability and operate in near-real time. Further, the adoption of interoperability standards, such as the work Standards Australia and the Energy Networks Association are doing in this space, along with open data sharing for the overall energy system, is recommended as it will ensure that new technologies and developments are interoperable.\(^{35}\)

- **consent** – in most cases, sharing and using data is acceptable under the Privacy Act if it takes place with the consent of the data subject. Currently, consent must be obtained in a transparent, fair and voluntary manner.

However, we recommend that – as part of the ACCC Consumer Data Right in Energy consultation - the nature and appropriateness of the current consent regime in energy be considered. As energy is an essential service, it is difficult to see how consumers would be able to withhold consent if it is bundled with their service offering, making the consent effectively involuntary. As more data is being shared, collected and accessed from consumers than ever before, it is crucial that customers are protected. We encourage regulators to consider alternative consumer protections such as prescribing “permitted uses” for all Market Participants when using consumer energy data.

### Recommendation #7:

**Mandate cooperation between traditional Market Participants and New Energy Service Providers and establish appropriate dispute resolution mechanisms, including establishing rules and procedures for financial licencing, billing, data exchange and security**

As the distribution network and associated markets become more complex, co-operation between market participants (particularly those at the same connection point) will become increasingly necessary. We recommend that consideration be given to the Distribution Systems and Markets Operators be charged with the role of not only appropriately managing the levels of co-operation but also overseeing potential disputes between market participants.

\(^{34}\) ACCC, *Consultation paper on energy data access models* (25 February 2019)

\(^{35}\) KWM, *Energy Storage Registration COAG Submission number 37* (20 September 2016)
Current state of play

The changing nature of the energy market will have a significant impact on the distribution network.

A key value proposition of New Energy Service Providers is their ability to support network service providers:

▪ with power system planning and maintenance so as to reduce spending on network infrastructure
▪ in operating their networks within technical and safety requirements
▪ in reducing congestion, smoothing network peaks and mitigating outages
▪ reduce or avoid transmission costs

Ideally, these benefits can then be passed onto consumers through lower network pricing.

There have been a number of significant positive developments in the network space that show strong buy-in from network operators and regulators in support of the potential benefits that distributed energy resources can provide. However, despite this, a number of structural challenges still act as barriers to New Energy Service Providers, particularly in the 3 areas below.

Network transparency and data

Imperfect information, including low visibility of network assets, and lack of data sharing can act to inhibit the realisation of New Energy Service Provider benefits, particularly in relation to network infrastructure costs and network planning decisions.

The lack of network asset visibility has resulted in less than desirable outcomes, including:

▪ limiting exports from distributed energy resources to the grid
▪ inability to value the benefit of New Energy Services
▪ information asymmetry when negotiating with network and retailers

Zero Offset and augmentation

The NER requires Network Operators to offer solar PV customers connection to the grid. Subject to the terms of their Connection Agreement, customers import/export electricity to the grid. However, it has been publicised that Network Operators are ‘offering’ connection to solar PV customers at a maximum capacity of “0” export. While this may comply with regulatory obligations, it is not particularly conducive to the growth of Active Consumers.

Network pricing

In Australia, network tariffs make up approximately half of the average Australian households bill.\textsuperscript{36} As such, it is equally important that Active Consumers receive the correct price signals from networks as they do from retailers. Cost reflective pricing is important. It means that consumers will pay (nearer) to the

\textsuperscript{36} Carbon and Energy Markets, “Network tariffs applicable to households in Australia: empirical evidence” (January 2015), page 6
actual cost of obtaining or providing electricity at different times and to different locations. This is particularly important in the context of New Energy Services and the business models that accompany them. AEMC has enacted significant rule changes in an effort to encourage cost-reflective network pricing (see Section 2 of "More Details"), however there has to date been limited take up of this new model of network pricing.

Why have the benefits of cost-reflective network pricing not materialised? The reasons could include:

- **opt-In**: while most networks now offer small customers cost-reflective network tariffs with robust methodologies, there are a range of barriers from metering, to industry structure, to behavioural preferences, which severely limit customer take-up. These are well documented in the 2016 publication, the *Electricity Network Tariff Reform Handbook.*

- In particular, the Australian Energy Regulator (AER) indicated in its Tariff Structure Statements that positive impacts won’t be achieved just by offering tariffs, in the absence of a more proactive strategy by networks to migrate small customers to these tariffs.

- According to the Network Tariff Reform Handbook, international experience suggests that assignment and opt-out approaches deliver more certain and quicker transitions to cost-reflectivity. However, this has not been the approached implemented in Australia. In fact the opposite has occurred in Victoria, where a State Government Order in Council was introduced preventing the assignment of customers to cost reflective prices, even where the customer retained the opportunity to ‘opt out’ to current tariff structures.

- **structural barriers**: while under the rule change, networks are permitted to take into account the location of consumers and the extent to which costs vary between different locations in their distribution network when determining LRMC, in reality, many State regulations prohibit this. For example, in Queensland, Tasmania and South Australia, small customers must be offered the same tariff regardless of their location. As this is a jurisdictional pricing obligation, it takes precedence over the rule change.

**Recommendations**

**Recommendation #8:**

*Enhance and maintain the visibility of and data available on the component parts of the distribution network*

Increasing data sharing among Market Participants is beneficial (see recommendation #7) however the availability of adequate distribution data is also required to ensure all Market Participants are able to assess the true cost and value of electricity services.

We recommend that distribution networks are incentivised to increase the collection of data to provide all Market Participants better visibility of the component parts of the distribution network. This will provide New Energy Service Providers sufficient information to target their services to avoid or mitigate grid augmentation requirements and costs.

Network co-ordination and balancing requires significantly more active power system management. However, as distributed energy resources are typically installed behind the meter, these resources are invisible to AEMO and network operators and cannot be actively managed. AEMC recently determined a rule change that has the potential to increase the visibility of distributed energy resources. However, the rule change is limited and we recommend that the register be built-on (in stages) to ensure that the register is beneficial to all Market Participants both now and in the future. Incremental changes that would benefit New Energy Service Providers and Active Consumers include:

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37 AEMC, *Distribution Market Model Report* (22 August 2017)
38 AEMO, *Submission to Government Inquiry into modernising Australia’s electricity grid,* page 5
allowing New Energy Service Providers simple and seamless access to data on the AEMO registry, provided the New Energy Service Provider has adequate customer consent.

expanding the register to include real-time data. Currently, AEMO monitors real time loads of large energy generators. In the future embedded generation and data associated with aggregated loads will be just as valuable, if not more valuable. In particular real time data will result in improved customer information, control and choice.39

Recommendation #9:
Mandate opt-out cost-reflective network pricing for retailers and remove structural barriers for uptake of cost-reflective pricing

The AEMC has already enacted significant rule changes to network pricing in this regard, however there has been limited take up to date of AEMC’s new model of network pricing. We recommend, in line with the ACCC Retail Electricity Pricing Inquiry – Final Report, that cost-reflective pricing be opt-out (rather than opt-in as it is currently) and that the State legislation that creates structural barriers to the uptake of locational based pricing be removed or amended.40

Recommendation #10:
Require networks to engage in good faith negotiations with New Energy Service Providers regarding network charging

Cost-reflective pricing (as above) is a positive step forward for Active Consumers, however there are many other alternative pricing models that may provide better outcomes (particularly for those involved in peer-to-peer trading). We recommend that, similar to the negotiated connection regime in Chapter 5, distribution networks be required to negotiate with New Energy Service Providers regarding network charging when benefits (such as grid augmentation avoidance) can be evidenced.

We also recommend consideration be given to the following as part of the process:

- **information equity** – requiring the Networks to provide (or collect if necessary) the data / information reasonably necessary to allow the New Energy Service Provider to negotiate on an informed basis (similar to Chapter 5A.C.3)
- **planning report** – requiring the Networks to provide to New Energy Service Providers network planning reports (similar to clause 5A.C.3)
- **timeframes** – mandate a maximum negotiation timeframe and response requirements for the Networks in respect of a New Energy Service Provider’s application (see Chapter 5A.D.3)
- **solution support** – requiring distribution networks to work with New Energy Service Providers to negotiate pricing for solutions that integrate distributed energy resources on a case by case basis (this goes further than the connection requirements – removing the current issues that are being seen with Chapter 5A (ie zero export)).

While cost-reflective pricing has been the chosen model in Australia, there are other alternative pricing models that may provide better outcomes for New Energy Service Providers and their Active Customers. We set out three alternative pricing models below, and recommend that rather than enshrining one model of pricing, New Energy Service Providers are empowered to negotiate the most suitable pricing model with distribution networks on a case by case basis.

39 KWM, Energy Storage Registration COAG Submission number 37 (20 September 2016)

40 ACCC Retail Electricity Pricing Inquiry – Final Report “Restoring electricity affordability and Australia’s competitive advantage”, page xix
Local generation network credits

The use of “Local Generation Network Credits” was proposed as a rule change in 2015 by the Property Council of Australia, the City of Sydney and the Total Environment Centre. The regime attempted to provide networks with a mechanism to price local electricity generation and consumption separately (and a lower rate) than consumption of centralised generation. In summary, the proposed rule change required networks to:

- calculate the long-term cost savings that generators of distributed energy (embedded generators) would provide to the distribution and transmission networks
- pay a local generation network credit (LGNC) that reflected those cost savings to all eligible embedded generators in their network area

The AEMC rejected the LGNC rule change proposal and stated that existing provisions for network support payments, combined with cost reflective tariffs, were sufficient to incentivise efficient local generation. While LGNCs are desirable in theory, there are major concerns with this approach. Most notably, the non-selective nature of the LGNCs will likely result in embedded generation being incentivised in areas where there are no system limitations, and a lack of investment in embedded generation where system limitations exist.

On the positive side, as a result of the LGNC rule change request, the AEMC did implement a change that required networks to annually publish system limitation information on:

- the geographical location and estimated duration of a system limitation identified during the forward planning period
- the network’s proposed solution to remedy the system limitation and the estimated costs of the network’s proposed solution
- the amount by which peak demand at the location of the system limitation would need to be reduced in order to defer the proposed solution and the dollar value to the network for each year of deferral

The above information requirement (coupled with existing network incentives) is a step towards encouraging networks to look to distributed energy resources for abatement – opening the potential for New Energy Service Providers to negotiate with networks to adjust or alter network tariffs based on potential value streams they could provide through local peer-to-peer trading and abatement. This would not however be a regulated mandate but rather a commercial decision for the network to consider and propose in their tariff setting process.

Local use of network service (LUOS)

Similar to the LGNCs is a change to network charging that would see networks offer local Active Customers who assign (or trade) excess electricity with other Active Customers (in a VPP or P2P scenario) an appropriately lower network charge for use of only the local network. Going further, this alternative model could be applied in a VPP / P2P scenario so that two Active Consumers could share the LUOS based on the network infrastructure required for the trade.

International example

The EU’s Clean Energy for all Europeans package sets out an interesting approach in the recently implemented change to the Renewable Energy Directive Article 22(4)(d). It states that:

“Member States shall provide an enabling framework to promote and facilitate the development of renewable energy communities. That framework shall ensure, inter alia, that renewable energy communities are subject to fair, proportionate and transparent procedures, including registration and licensing procedures, and cost-reflective network charges, as well as relevant charges, levies and taxes, ensuring that they contribute, in an adequate, fair and balanced way, to the overall cost

41 AEMC, Local Generation Network Credits Rule Change (10 December 2015)
sharing of the system in line with a transparent cost-benefit analysis of distributed energy sources developed by the national competent authorities”\textsuperscript{42}

An example of a business model taking advantage of this new right is Next Kraftwerke’s “German project”. Next Kraftwerke provides ‘midscale’ customers with time variable tariffs including ‘grid-charge optimisation’ to help consumers benefit from market signals through time variable tariffs while also taking into account grid charges. It is Next Kraftwerke’s view that by optimising the capacity tariffs and individual network tariffs, customer revenues can be optimised.\textsuperscript{43}

Recommendation #11:
Better integrate renewables by investing in and managing the grid so as to avoid zero export

The European Commission has proposed a number of new legislative requirements on all Member States, as part of a reform to the EU’s electricity market design, to give equal access to all energy providers. This includes residential solar.\textsuperscript{44}

Specifically, the following Directive / Regulatory changes have been proposed:

- **Renewable Energy Directive, Article 21**: that renewables self-consumers, individually or through aggregators, are entitled to generate renewable energy including for their own consumption and store and sell their excess production of renewable electricity, including through renewables power purchase agreements, electricity suppliers and peer-to-peer trading arrangements, without being subject to discriminatory or disproportionate procedures and charges or to network charges that are not cost-reflective\textsuperscript{45}

- **E-Directive, Article 15**: that “final customers” are entitled to generate, store, consume and sell self-generated electricity in all organised markets either individually or through aggregators without being subject to disproportionately burdensome procedures or charges\textsuperscript{46}

- **Electricity Regulation, Article 3(1)(d)**: that market participation of consumers and small businesses shall be enabled by aggregation of generation from multiple generation facilities or load from multiple demand facilities to provide joint offers on the electricity market and be jointly operated in the electricity system, subject to compliance with EU treaty rules on competition\textsuperscript{47}

Using the EU as an example, we recommend that Chapter 5A be amended to ensure that solar connection and export is adequately supported (rather than individual customers being obliged to pay for grid augmentation) with the costs of this being shared fairly and reasonably among all energy market participants and customers. We acknowledge, in saying this, that the costs of grid augmentation will need to be carefully balanced against the benefits this will deliver to the consumer and more broadly to the future transition to a flexible energy mix.


\textsuperscript{43} Engerati, “Business models for renewable aggregation – what is ready” (27 September 2018)

\textsuperscript{44} European Commission, Clean energy for all Europeans (website)


\textsuperscript{46} Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on common rules for the internal market in electricity (recast) (23 February 2017)

\textsuperscript{47} Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the internal market for electricity (recast) (23 February 2017)
Section 1: Current retail framework

Below we set out how new business models operate within the current framework, highlighting some of the restraints the current framework places on the business models of New Energy Service Providers.

Operating as a Retailer

Section 88 of the NERL requires that anyone who sells energy to people for use at premises must have either a retailer authorisation or a retail exemption. Energy sales do not necessarily have to be for profit – passing on energy costs to another person is considered to be a sale.

New Energy Service Providers could act as a traditional retailer, offering a new model of pricing and alternative services. This would allow the New Energy Service Provider to have full control over the local energy marketplace, allowing it to implement any pricing model (including reflecting spot market pricing or ‘netting off’ between local market participants). However, this option would also require the New Energy Service Provider to take on 100% of the risk, including the complexities of retail businesses such as hedging, prudential requirements, settlement, billing and compliance.

While it is possible for New Energy Service Providers to be licenced as retailers, it is questionable if this is the most desirable outcome. In particular, New Energy Service Providers:

▪ are often at the infant stage of commercialising new or innovative products. As such, it is unlikely that they have the capital, expertise and systems to take on all the responsibilities and risks of a retailer. There is a real concern that requiring New Energy Service Providers to be licenced will ‘freeze out’ new entrants and in turn dampen innovation in the NEM
▪ offer a different service to traditional retailers. Most commonly, New Energy Service Providers sell flexibility and trade it on the NEM on behalf of Active Consumers. Active Consumers offer New Energy Service Providers a number of ‘tradeable products’ including:
  ▪ excess solar generation
  ▪ avoided consumption during times of grid restraint
  ▪ grid-stabilising services (ie FCAS and ancillary services)

This business model is fundamentally different from that of traditional retailers as its focus is not on the consumption of electricity, but rather flexibility of demand. In reality the two should offset each other leading to lower overall energy costs for the Active Consumer.

Partnering with a Retailer

New Energy Service Providers which do not wish to be licenced as a retailer can partner with an authorised retailer to provide ‘secondary’ services. The retailer remains responsible for all settlement and billing as the Financially Responsible Market Participant. While this is currently permissible under the NER, it requires a willing retailer to cooperate with New Energy Service Providers. Under this model the delineation of liability and responsibility is complex, and negotiations by New Energy Service Providers with established retailers often place a large strain on resources.
It is also important to understand that traditional retailers and New Energy Service Providers can have opposing interests. At a basic level, traditional retailers sell electricity, deriving profits from consumption from the grid, whereas New Energy Service Providers sell flexibility and aggregated generation. The co-operation model, currently seen as the more viable option for New Energy Service Providers entering the Australian market may therefore prove difficult to put in place with retailers, and even if put in place, prove counterproductive for the New Energy Service Providers and the Active Consumer. This model may:

- stifle competition in the energy market, forcing consumers to enter into set tariff structures with the retail partner. This undermines the right of consumers to switch retailers and choose their own tariff structures
- decrease the offering of New Energy Service Providers, particularly in the area of demand response where retailers are traditionally paid by customers for consumption
- increase the risk profile for the retailer (for example the New Energy Service Provider may have control over the price that energy is bought or sold by the retailer in the wholesale market)
- stifle the New Energy Service Provider’s offerings and innovation (as the retailer may not be comfortable with another party influencing wholesale purchasing decisions).

This co-operation model creates an unregulated ‘quasi’ market participant, with the only recourse being contractual obligations to the retailer.

**Operating as an exempt Retailer**

Another option for New Energy Service Providers is to operate under the Australian Energy Regulator’s exempt seller regime. This regime enables companies to offer New Energy Services without becoming a FRMP and an authorised retailer.

This would enable a New Energy Service Provider to buy and sell electricity on behalf of customers without a retail licence. Utilising the individual exemption framework, it is possible that the AER could decrease some of the regulatory requirements, in effect tailoring the licencing regime of traditional retailers for a New Energy Service Provider. In fact, the AER can:

- impose conditions as it chooses and these conditions can be tailored to the scope and nature of activities being undertaken. Generally, conditions will relate to the sale of electricity to exempt customers and conditions on pricing and prudential standards
- set a term of the exemption, ensuring a review of the exemption is undertaken regularly

However, we must recognise that traditional retail relationships provide customers with security and protections. When looking for regulatory change, it is crucial not to underestimate the role of the retailer as a provider of security for energy consumers – retailers act as a buffer to spot market price fluctuations and also ensure security of supply.

If the AER were to go down this path of ‘quasi-licencing’, options include:

- defining eligible customers (ie ensuring that Hardship Customers or other vulnerable customers are not able to sign up to New Energy Service Provider’s offerings)
- requiring the New Energy Service Provider to engage with a traditional retailer to satisfy conditions such as prudential standards and billing
- imposing regular reviews and licence condition audits to ensure customers are satisfied and protected

The UK has taken active steps to formalise such an approach. In 2015, “Licence Lite” was introduced by Ofgem as an alternative electricity supply licensing option. The regime was intended to “ease potential barriers to entry faced by aspiring suppliers”. Under the Lite supply licence, an energy supplier could outsource the more complex ‘compliance’ burdens to Third Party Licenced Suppliers. In effect, “piggy-backing” on a retailer’s licence, while still being able to remain the sole supplier of electricity to customers.

Originally, Ofgem intended that this model would support small-scale electricity generators to enter the retail market and supply local customers. However, it seems that prospective suppliers have seen the
benefits of the Licence Lite model as an alternative to the restrictions imposed by the primary route to supply, the “Class Exemption Order”. For example, Evenergi UK Limited, a home and electric vehicle energy usage monitoring company, was the first to be approved under the Licence Lite regime. It is unclear at present what plans Evenergi has with respect to its retail offering, however this example highlights an innovative regulatory solution which facilitates new business models in the retail energy space.

While the Ofgem ‘Licence Lite’ model has not yet proved resoundingly successful, it is a positive regulatory change in regard to facilitating choice – allowing New Energy Service Providers to be the FRMP while also acknowledging the role traditional retailers play in consumer protections and compliance.

**Market Small Generation Aggregator**

In 2012, AEMC passed a rule change that created a new Market Participant – the Market Small Generation Aggregator (MSGA). The framework was established to allow the owners of small generating units to have the additional option of selling electricity from those units to a Small Generation Aggregator instead of a Market Customer. Under this rule change, the MSGA (or the owner of the small generating units) does not have to register as a Generator with AEMO to directly participate in the NEM.

However, as discussed above, each connection point through which energy is imported must have a Financial Responsible Market Participant. Given this, if there is only a single connection point, and energy will be imported and exported through it, an MSGA is effectively required to also hold a Retail Licence.

Clause 2.3A.1 of the NER also precludes an MSGA from participating in market ancillary services - it can only provide energy services.

Due to the above restrictions, MSGA service models are currently limited to the large customer segment of the market, as these are the customers likely to find it economical to establish a second connection point for the purposes of selling embedded generator output.

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48 Clause 2.3, National Electricity Rules
Section 2: Multiple Trading Relationships – rule change attempts

In December 2014, AEMO requested a rule change to enable consumers to enter into trading relationships with multiple financially responsible market participants. It proposed the establishment of multiple trading relationships at a premises. AEMO stated that the current rules were overly costly and complex, acting as an unjustified barrier to the kind of services that New Energy Service Providers can offer.

In February 2016, the AEMC declined to make the rule change, stating that while a small number of consumers would benefit from multiple trading relationships, most would not experience any reduced costs. Further, the AEMC said that the proposal would require significant, costly modifications to retailers’ and DNSPs’ systems. These costs would likely be passed on to all consumers in the form of increased electricity retail prices. As an alternative, AEMO suggested that if consumers wanted to engage two service providers they would require dual connection points. The costs of this “solution” were significant as it required:

- investment to rewire the premises to establish the second connection point
- investment to install a second meter at the premises
- the payment of dual network tariffs.\(^{49}\)

This solution, to our knowledge, has not been taken up by any New Energy Service Providers – most notably as it not palatable to consumers as the costs are seen as both unnecessary and duplicative.

AEMC in their 2018 Reliability Frameworks Review recommended that AEMO submit a rule change request to AEMC by the end of 2018 (which at the date of this paper has not yet occurred) to allow customers to engage multiple service providers behind the same connection point. AEMC proposed that New Energy Service Providers would be allowed to be a FRMP behind a connection point for a subset of the resources (such as selling generation to the wholesale market or engaging in demand response) without becoming the FRMP for all of the load behind the connection point.

### Section 3: Energy data access

The ACCC consultation on the Consumer Data Right in energy sets out the current access arrangements:

<table>
<thead>
<tr>
<th>Type of data</th>
<th>AEMO</th>
<th>AER/Victoria Energy Compare</th>
<th>Retailers</th>
<th>Metering Data Providers</th>
<th>Distributors</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>NMI Standing data</strong></td>
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<td>Connection point information</td>
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<td><strong>Customer provided data</strong></td>
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<td>Name of account holder, contact details including billing address/postal address, information provided re customer appliances, etc.</td>
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<tr>
<td>Data collected by metering data providers or otherwise estimated or substituted by Metering Data Providers. AEMO does not currently hold all metering data (it is not as rich as what other market participants hold).</td>
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<tr>
<td><strong>Billing data</strong></td>
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<tr>
<td>Historical billing information for each connection point to which they have delivered electricity</td>
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<tr>
<td>Retail tariffs, usage charges, applicable discounts for the supply of electricity to consumers</td>
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<td><strong>Product data – individually tailored</strong></td>
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<tr>
<td>Retail tariffs, usage charges, applicable discounts for the supply of electricity, specific to a consumer</td>
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<tr>
<td><strong>Distributed Energy Resource Register</strong></td>
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</table>
Section 4: Access Model

Model 1, the AEMO centralised model – AEMO would be the sole data holder of the centralised data set, which includes consumer energy data that it currently does not hold and would be responsible for providing CDR data directly to accredited data recipients. This would require:

- data holders to build APIs to provide CDR data to AEMO for centralised storage; and
- AEMO to build open APIs to provide that data to accredited data recipients (which could include those outside the energy industry – which is both exciting and concerning for bundling products).

Model 2, the AEMO gateway model – AEMO would provide a gateway function (acting as a pipeline for the provision of CDR data from data holders which may include retailers and potentially also distributors, to accredited data recipients) and may also be a data holder providing CDR data directly to accredited data recipients. This would require:

- AEMO to build a gateway through which AEMO (on behalf of energy data holders) provide CDR data to accredited data recipients.
- Data holders to build web-based APIs that enable ‘on demand’ provision of various energy data sets.

Model 3, the economy-wide CDR model - existing data holders (for example, retailers) would be responsible for providing CDR data directly to accredited data recipients and/or consumers i.e. the model used for the banking sector. This would require:

- Accredited data recipients and/or consumers themselves directly contracting the data holder responsible for collection and management of relevant data sets;
- Participants and potentially also AEMO and government-provided energy comparator services to build open APIs for the provision of data accredited data recipients.

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ACCC, Consultation paper on energy data access models (25 February 2019)
Section 5: DER coordination challenge

51 Energy Networks presentation, Energex Brisbane 2016 page 50
Section 6: Network pricing

Before looking at how network pricing can be more cost-reflective, it is important to recognise the significant changes in regulations that have acted to help address network pricing and why network pricing is the way it is currently.

Originally, each consumer was required to pay a proportion of total network costs depending on their level of consumption – this pricing model operated irrespective of timing (peak or non-peak use of the grid) or location of that consumption. This structure aimed to over-recover revenue for off-peak prices and under-recover for peak use, was clearly not cost-reflective and led to a situation where customers who used off-peak power were paying more and those using peak power were paying less.

Further, the principle of equal access to the grid underpinned much of the network regulation until very recently. Under this pricing structure, the costs of the network fall disproportionately on those who rely on the network for their electricity compared to those who rely on it only partially (due to solar and/or batteries). The impact of this is that households are encouraged to self-consume, rather than feeding electricity back into the grid. This incentive is particularly perverse if you have a short fall in supply or if you consider that local energy can be less of a strain on the electricity grid (ie electricity does not have to travel through as much of the grid). Further, it arguably undervalues the back-up or insurance value of the grid and creates a form of cross-subsidisation from those who do not generate electricity by those who do.

As a reaction to these concerns, AEMC implemented a rule change in 2014. The rule change established a new pricing objective for networks, focused on cost-reflective pricing. The rule change was aimed at ensuring networks take into account how future costs vary by location and time of peak utilisation, and signalling these cost drivers to consumers. Under the rule, networks are required to comply with 4 new pricing principles:

▪ network tariffs must be based on the long run marginal cost (LRMC) of providing the network service
▪ total revenue to be recovered (as determined by AER) must be recovered in a way that minimises distortions to price signals and encourages efficient use by consumers - DNSPs may determine how this is done and are subject to a number of constraints in doing so
▪ tariffs must be developed with regard to the impact on the consumer and networks must develop pricing structures that can be understood by consumers
▪ network tariffs must comply with jurisdictional (State and Territory) pricing obligations in a transparent way

The purpose of the rule change was to encourage investment in energy efficiency technologies, west-facing solar panels (for generation at peak times), battery storage and locating businesses in areas where network costs are lower. It was anticipated that consumers would respond to new network price structures by reducing their use of the network at peak times, thereby reducing overall network costs. The cost saving would then be passed on to all consumers through lower future network charges, although how the cost of “stranded” investment would be recovered remained unresolved. The pricing structures applied from January 2017 and were rolled out on a network-by-network basis in accordance with regulatory determinations.

The AEMC rule change and the move toward cost-reflective pricing is significant. Despite the potential value of the reform to customers, the benefits of it are yet to be realised. In March 2017, Energy Networks Australia illustrated with the below graph the lack of consumer take up for the new network pricing structures:

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However, the lack of take up is not the only issue that continues to plague network pricing reform.

<table>
<thead>
<tr>
<th>NEM Region</th>
<th>Average years alternative cost reflective tariffs available</th>
<th>Customers still assigned to legacy volume tariffs (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSW/ACT</td>
<td>14</td>
<td>88%</td>
</tr>
<tr>
<td>QLD</td>
<td>5</td>
<td>100%</td>
</tr>
<tr>
<td>VIC</td>
<td>14</td>
<td>89%</td>
</tr>
<tr>
<td>SA</td>
<td>2</td>
<td>100%</td>
</tr>
<tr>
<td>TAS</td>
<td>8</td>
<td>100%</td>
</tr>
<tr>
<td>NEM</td>
<td>11</td>
<td>92%</td>
</tr>
</tbody>
</table>
Section 7: Regulatory reform and government reviews

1 Government Reviews / Inquiries:
   - Finkel Review Independent Review into the Future Security of the National Electricity Market (June 2017)
   - Report for DoEE Facilitating access to consumer electricity data (Feb 2018)
   - ESB and AEMO Annual report into the cyber security preparedness of the NEM (Dec 2018)
   - Commonwealth Government Inquiry into modernising Australia's electricity grid (Feb 2017)

2 AEMC Reviews/ Inquiries:
   - Distribution Market Model Review (August 2017)
   - Reliability Frameworks Review (July 2018)
   - Frequency control frameworks review (July 2018)

3 AEMO advice to government:
   - Advice to Commonwealth Government on Dispatchable Capability (Sept 2017)
   - AEMO submission to the Inquiry into modernising Australia's electricity grid (Feb 2017)

4 Programs / working groups:
   - ENA and AEMP Open Energy Networks
   - AEMO VPP Demonstrations
   - AER and ARENA Distributed Energy Integration program

5 Rule Changes:
   - Register of Distributed Energy Resources (Aug 2018, rule made)
   - Wholesale Demand Response Mechanism (Nov 2018, consultation)
   - Advanced meter communications (Oct 2018, consultation)
   - Enhancement to the Reliability and Emergency Reserve Trader (June 2018, consultation)
   - Contestability of energy services (Dec 2016, rule made)
   - Inertia Ancillary Service Market (Sept 2016, not successful)
   - Non-scheduled generation and load in central dispatch (Aug 2017, not successful)
   - Local Generation Network Credits (Dec 2016, not successful but rule made about DNSP publishing network information)
   - Demand Response Mechanism and Ancillary Services Unbundling (Oct 2016, rule made)
## Section 8: Project description

### Structure and intended operations of LTVM

<table>
<thead>
<tr>
<th>Objective</th>
<th>To demonstrate how local distributed energy resources and demand response can be incorporated into a local marketplace to improve the efficiency, security and resiliency of the electricity grid and improve economic outcomes for participants.</th>
</tr>
</thead>
</table>
| Marketplace Participants (Dairy Farms) | Up to 200 dairy farms in the Latrobe Valley. The participating dairy farms will be a mix of both consumers and prosumers able to input generation, utilise demand response software or storage in the marketplace.  
  
  Each dairy farm will have a tailored solution based on specific needs and demand profiles.  
  
  Preliminary analysis of farms in the LTVM region indicates that the average farm is likely to support 80 kW solar and 250 kWh battery storage.  
  
  Dairy farms have a fairly rigid energy consumption profile, with the capacity to sell excess energy during the day and potentially discharge from batteries. |
| Virtual Microgrid Participants | The LTVM entity will identify 100-150 residential energy customers and 10-20 commercial/industrial customers (likely to include some of the participating dairy farm co-operatives) willing to participate in a virtual microgrid (ie participants use existing network infrastructure and are not able to island from the grid) to trial local energy marketplace software for a minimum of 12-months.  
  
  The microgrid will enable participants to buy and sell generation from distributed renewable energy resources, such as PV or batteries, be rewarded for their demand response capability (where it is requested by the network operator), and any grid stability services provided. |
| Virtual Microgrid Technology | **Microgrid application** The microgrid members will provide preferences and be able to respond dynamically using a mobile application (see Section 9 of “More Details”). The app will at a minimum allow for setting of price sensitivity, preferences for energy supply, and demand response capability of various devices for financial return.  
  
  **Microgrid software** The microgrid will utilise blockchain technology to balance demand and supply and maximize load shifting.  
  
  A TAG-e (hybrid meter/computer device developed to meet traditional hardware requirements for revenue grade utility meters) will apply smart contracts which will executed by reference to price and other user preferences.  
  
  TAG-e controls those devices within its defined jurisdiction and securely communicates its decisions to other TAG-e devices via the blockchain network.  
  
  There are two layers of functionality:  
  
  - a transactive layer enabling device-to-device energy trading transactions integrate data such as generating efficiency, carbon intensity and location-based pricing  
  - a control layer containing control logic linking the transactive layer and device outcomes. Control commands will be executed based on signals from the transactive layer via self-executing smart contracts. |
<table>
<thead>
<tr>
<th>Structure and intended operations of LTVM</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Corporate off-taker</strong></td>
</tr>
<tr>
<td><strong>Financing</strong></td>
</tr>
<tr>
<td><strong>Energy charges</strong></td>
</tr>
</tbody>
</table>
Section 9: Application Functionality

Figure 1: Mobile app ability for customers to select their own power supply (indicative only)
Figure 2: Mobile app ability for users to see generation as well as select devices for demand response

Figure 3: Mobile app ability for users to see where energy is generated and add or suggest new distributed energy resources

Figure 4: Mobile app ability for users to see their profile, activities, and compete with other users

Figure 5: Mobile app ability to view historical energy information
A New Energy Future is on the horizon. New energy sources, smart technologies, industry fragmentation and empowered consumers are set to transform the industry. In this new and uncertain future where innovation is key, our new energy team helps start-ups, retailers, network service providers, regulators and other new entrants get creative. We understand the challenges and opportunities specific to the industry and we bring a team of experts to help you navigate the issues to achieve growth and success.

**Multidisciplinary expertise**

Drawing together expertise across projects, M&A, finance, regulatory, tax and intellectual property, we provide unique insights and valuable advice on new energy projects and transactions, including on:

- blockchain and smart contracts
- cloud based technologies
- regulatory including prospective regulatory change
- intellectual property
- supply and licensing agreements

A transformation of the energy industry is inevitable and will require a shift in how energy markets function physically, commercially and legally. The questions that will define business decisions and policy prescriptions vary by industry and participant. Contact us to discuss your market strategy and explore the questions and issues you are facing as you adapt and position yourself ahead of this transformational change.

**Contact us**

**SCOTT GARDNER**
Partner
T +61 2 9296 2158
M +61 419 533 313
scott.gardner@au.kwm.com

**Acknowledgements**

Contributors: Odietta Adams, James McGrath and Lauren Murphy

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