Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Attachment 5-5

Innovation and technology investment

Public

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ABBREVIATIONS

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
CCHP	Cooling, Heat and Power
CHP	Combined Heat and Power
CPP	Critical Peak Pricing
DLC	Direct Load Control
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNPE	Distribution Network Planning and Expansion
DNSPs	Distribution Network Service Providers
DR	Demand response
DRED	Demand Response Enabling Device
DRFT	Demand Response Field Trial
DSED	Demand Side Engagement Document
DSP	Demand Side Participation
EODMS	Electricity Outlook Demand Management Study
ESMS	Electricity Safety Management Scheme
ESV	Electricity Safe Victoria
HAN	Home Area Network
HV	High Voltage
IHD	In Home Display
JEN	Jemena Electricity Networks (Vic) Ltd
LV	Low Voltage
NEM	National Electricity Market
NER	National Electricity Rules
PCS	Power Conversion System
PV	Photovoltaic
RAB	Regulatory Asset Base
ToU	Time of Use

OVERVIEW

1. The electricity supply industry in general and distribution networks in particular are undergoing rapid change with the evolution of new technologies that are impacting the ways in which networks are planned, operated and maintained. Customers are increasingly looking for service providers to provide them with flexible and cost efficient solutions for managing energy consumption. Government policy and new regulatory frameworks are being formulated to respond to these technology innovations and consumer preferences.

2. In this environment, Jemena Electricity Networks (Vic) Ltd's (**JEN's**) network investment objective is *to provide network services that are safe, affordable and responsive to our customers' preferences while enabling innovation and change*.[1]

3. Demand management aims to manage the electricity use profile on a network so as to minimise the cost of supplying customers while maintaining or improving customer options and service levels, and is defined by the Australian Energy Regulator (**AER**)[2] as:

> *"Demand management projects or programs are measures undertaken by a DNSP to meet customer demand by shifting or reducing demand for standard control services through non-network alternatives, or the management of demand in some other way, rather than increasing supply through network augmentation."*

4. JEN considers non-network solutions as any activity, service or product that does not involve the construction of the traditional poles and wires network. These include, but are not limited to, tariff offerings; demand response; embedded generation; energy storage; and energy efficiency incentive programs.

5. Our objectives over the next five years for demand management are to:

    1. Develop options and flexibility for both our network and our customers through the application of demand management solutions;
    2. Establish policy, systems and processes that support demand management; and
    3. Where economical, resolve network supply quality and capacity constraints using demand management.

6. The rules require the AER to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to building more network solutions.[3] To meet this requirement, and motivated by the need to improve the five Victorian electricity distributors' capability in the demand management area, the AER is proposing to implement a demand management and embedded generation connection incentive scheme (**DMEGCIS**[4]) in the distribution determinations for the 2016 regulatory period.

7. The DMEGCIS is designed to complement the broader regulatory framework in providing incentives for distribution network service providers (**DNSPs**) to trial innovative non-network alternatives for managing

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[1] Jemena Electricity Networks – 20 Year Strategic Asset Management Plan - Electricity

[2] AER, *Demand Management and Embedded Generation Incentive Scheme, Jemena, CitiPower, Powercor, AusNet Services and United Energy, 2016-20, 21 November 2014*, Section 3.1.3 – The DMIA criteria, Item 1.

[3] National Electricity Rules, clause 6.6.3(a)

[4] AER, *Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016*, 24 October 2014, footnote 275 "The rules have since changed the name to 'Demand Management and Embedded Generation Connection Incentive Scheme' (DMEGCIS) to explicitly cover innovation with respect to the connection of embedded generation. Our current and proposed DMIS include embedded generation. We consider embedded generation to be one means of demand management, as it typically decreases demand for power drawn from a distribution network".

expected demand for standard control services. It supplements a DNSP's approved capital and operating expenditure, to facilitate investigation and implementation of demand management strategies.

8. In order to meet our demand management objectives, JEN is seeking approval of the following projects under the demand management innovation allowance (**DMIA**) for the 2016 regulatory period:

1. **Efficient connection of micro-embedded generators**
   Maximizing the capacity of low voltage networks for efficient connection of inverter based micro-embedded generators
2. **Direct load control trial**
   Direct control of customer appliances utilising the advanced metering infrastructure (**AMI**)
3. **Managing peak demand through customer engagement**
   Empowering customers to make informed decisions through education, incentives and analytics
4. **Technology and economic assessment of residential energy storage**
   Evaluate technical and economic viability of residential scale energy storage solutions when deployed in conjunction with rooftop solar photovoltaic (**PV)** systems
5. **Distributed grid energy storage**
   Storage solutions to mitigate network capacity constraints and maintain quality of electricity supply
6. **Demand response field trial – phase 2**
   Following on from the development of desktop models developed in 2014 (phase 1), phase 2 aims to understand practical issues associated with dispatch and control of demand response.

9. The overall objectives of these proposed projects are in agreement with the AER's DMIA criteria.

10. Table OV–1 depicts the consolidated total projected cost of the proposed DMIS trial program. It includes a cost breakdown for each trial and the year in which the expense is expected to be incurred.

Table OV–1: Total projected cost of DMIS trial program ($2015, $ thousands)

Trial No.	Trial Name	2016	2017	2018	2019	2020	Total cost (2016 - 20)
1	Efficient connection of micro embedded generators			153	306	306	765
2	Direct load control trial		207	414	414		1,035
3	Managing peak demand through customer engagement	320	320				640
4	Technology and economic assessment of residential energy storage				244	366	620
5	Distributed grid energy storage	369	739	739			1,847
6	Demand response field trial	396	264				660
Total		1,085	1,530	1,306	964	672	5,557

11. The DMIA will be provided as an annual, ex-ante allowance in the form of a fixed amount of additional revenue at the commencement of each regulatory year of the regulatory control period. The total amount of the allowance will be distributed evenly across each regulatory year of the regulatory period.[5]

12. JEN proposes that the total amount recoverable over the 2016 regulatory period under the DMIA as $5.557m. Within the regulatory period JEN proposes to have the flexibility to select an expenditure profile that suits its needs, as projected in table above.

5 AER (Australian Energy Regulator), *Demand Management and Embedded Generation Incentive Scheme, Jemena, CitiPower, PowerCor, AusNet Services and United Energy, 2016-20*, 21 November 2014, Section 3.1.2 – Access to the DMIA

1. BACKGROUND

13. JEN distributes electricity to over 319,000 customer sites via approximately 11,000km of distribution lines and over 950 square kilometres of north-west greater Melbourne. The network footprint incorporates a mix of major industrial areas, residential growth areas, established inner suburbs and the Melbourne International Airport.

14. This section provides a brief summary of the important drivers that influence our activities in the area of demand management and form the basis of the demand management trial projects being proposed for the 2016 regulatory period (see Section 3).

1.1 POLICY AND REGULATION

1.1.1 POLICY

15. Given the essential nature of the services JEN provides to its customers, electricity distribution is subject to a high degree of safety, technical, economic and other regulations. Additionally, both jurisdictional and Federal Government policies can have a significant impact on our business, services and customers.

16. Government environmental policy has previously been, and is likely to continue to be, a key enabler of mass-market take-up of new technologies which significantly impact the way our customers use and generate electricity. For example, policies encouraging the large scale take-up of rooftop PV solar systems have accelerated its development and added to downward pressure on manufacturing costs as the technology matures. Such policies have included schemes which provide subsidies for the purchase of PV systems (such as the Small Scale Renewable Energy Scheme) and mandatory premium feed-in tariffs. With the costs of solar PV systems now falling significantly, policies and subsidies designed to encourage its take-up have begun to be wound back. It is possible that future schemes—such as feed-in tariffs or up-front subsidies—are introduced to encourage the greater take-up of new technology.

17. Energy efficiency policies involve the establishment of minimum energy efficiency standards for buildings and consumer goods or providing equipment to households and businesses which assist them to reduce energy consumption. These policies generally have the effect of reducing peak electricity demand as well, and the achievement of greater efficiency has been facilitated by technological developments (such as energy efficient lighting) and the falling cost of these measures.

18. Government policy is likely to continue to play a key role in driving the take-up of new technologies which impact the way customers use our services. The mass-market deployment of distributed battery storage systems and policy decisions relating to electric vehicles could have a significant influence on JEN's assets and services. While these new technologies are generally not economic for most customers to install at the present time, the introduction of policies to encourage their take-up as they near the 'tipping point' of becoming economic could significantly change the way our customers source electricity from the grid.

1.1.2 REGULATION

19. As policy makers provide high-level direction to the development of regulatory frameworks, these frameworks can change in response to community concerns. For example, increases in electricity prices in the first part of this decade have caused significant interest in these issues[6] and the Better Regulation[7] program of reforms to the regulatory framework is aimed at addressing these concerns.

[6] Department of Industry, *Energy White Paper – Green Paper 2014*

Power of Choice

20. Demand side economics for essential services such as electricity works if consumers make informed choices as to how they make use of it. In making informed and efficient choices they need: information, education, incentives and the appropriate technology. Over the past few years, a great deal of work has been undertaken at the national level by a number of federal government agencies into giving consumers more choice as to how they consume electricity. This work culminated in the Australian Energy Market Commission's (**AEMC**) Power of Choice review into demand side participation (**DSP**), whose final report was released in November 2012.[8]

21. The overall objective of AEMC's Power of Choice review is to *ensure that the community's demand for electricity services is met by the lowest cost combination of demand and supply side options.* The AEMC further noted that this objective is best met when consumers are using electricity at the times when the value to them is greater than the cost of supplying that electricity (i.e. the cost of generation and poles and wires).

22. The final recommendations of the review foreshadowed change to the existing market and regulatory environment made necessary due to the rapidly evolving technological developments. A number of these recommendations have a significant impact on how distribution businesses such as JEN plan and operate their networks and in particular the role of demand side management in providing the best value solutions that customers desire. The package of reforms will ultimately create the right conditions for the evaluation and implementation of demand side management options, in order to meet the AEMC's objective stated above.

Distribution Network Planning and Expansion Framework

23. The Power of Choice review provided recommendations on amendments to the National Electricity Rules (**NER**) of the electricity regulatory framework governing the National Electricity Market (**NEM**). One of the rule determinations incorporates common planning requirements across all DNSPs in the NEM. This is the National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012 No. 5[9] ('**the Rule**').

24. In making its recommendation for the rule change, the AEMC noted a view that there was a lack of consistency and transparency by both DNSPs and market participants that created a bias against the consideration of non-network options and impeded investment in these options. The objective of this rule change was to implement a national framework for distribution network planning and expansion, which addresses these shortcomings. The rule includes development of a Demand Side Engagement Strategy[10] to be published in a Demand Side Engagement Document (**DSED**)[11].

25. The new Distribution Network Planning and Expansion (**DNPE**) framework flowing from AEMC's package of reforms requires DNSPs to develop a Demand Side Engagement Strategy that states how they will engage with non-network providers and consider non network options. There is also a requirement to maintain a register of non-network solution providers and set up a process of engagement and consultation to determine their interest and ability to be involved in the development of non-network solutions.

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7 http://www.aer.gov.au/Better-regulation-reform-program

8 AEMC (Australian Energy Market Commission) *Power of choice review – giving consumers options in the way they use electricity, Final Report*, 30 November 2012,

9 http://www.aemc.gov.au/Electricity/Rule-changes/Open/distribution-network-planning-and-expansion-framework.html

10 NER, cl 5.13.1 (e)

11 NER cl 5.13.1 (g)

1.2 NETWORK

1.2.1 EXPENDITURE DRIVERS

26. The expenditure drivers for JEN are outlined and individual asset class strategies are summarised in the Asset Management Strategy and Objectives document[12]. JEN's expenditure drivers include technical compliance; energy, maximum demand and customer numbers; asset replacement; and community expectations.

Technical Compliance

27. The technical compliance driver includes guaranteed service levels that we must adhere to, but also safety and environmental compliance requirements. It considers the actual and desired level of reliability and quality of supply on our network; and the technical, safety, environmental and other obligations we comply with (corporate and legislative requirements).

28. The requirement to maintain assets and operational safety is a key driver. A network failure can cause personal injury or loss of life, property and environmental damages and loss of supply. Our asset management activities need to comply with corporate and legislative requirements, including adherence to JEN's Electricity Safety Management Scheme (**ESMS**) approved by Energy Safe Victoria (**ESV**).

Energy, maximum demand, and customer numbers

29. This driver is defined as the maximum demand that our network will need to meet, number of customers that we will need to serve, and the amount of electricity that our customers will consume per year.

Asset Replacement

30. The asset replacement driver is defined as the refurbishment and replacement of assets based on their condition, age, failure rate and technology efficiency. Asset class strategies are developed to ensure that the assets are managed optimally, thereby balancing capital and operational expenditure with the performance, risks and costs associated for the assets.

31. Replacements are prioritised based on their criticality and the ability of the plans identified to meet the long-term interests of our customers. This helps us to balance the individual asset class drivers, with an overall network view so that we can optimise the outcomes from the strategies.

Community Expectations

32. The community is defined as our customers, network users, the industry regulators, government departments and the broader community. The community expects environmental responsibility; a safe and reliable level of service; responsive service; public amenity; equitable levels of service available to all consumers; and affordable pricing.

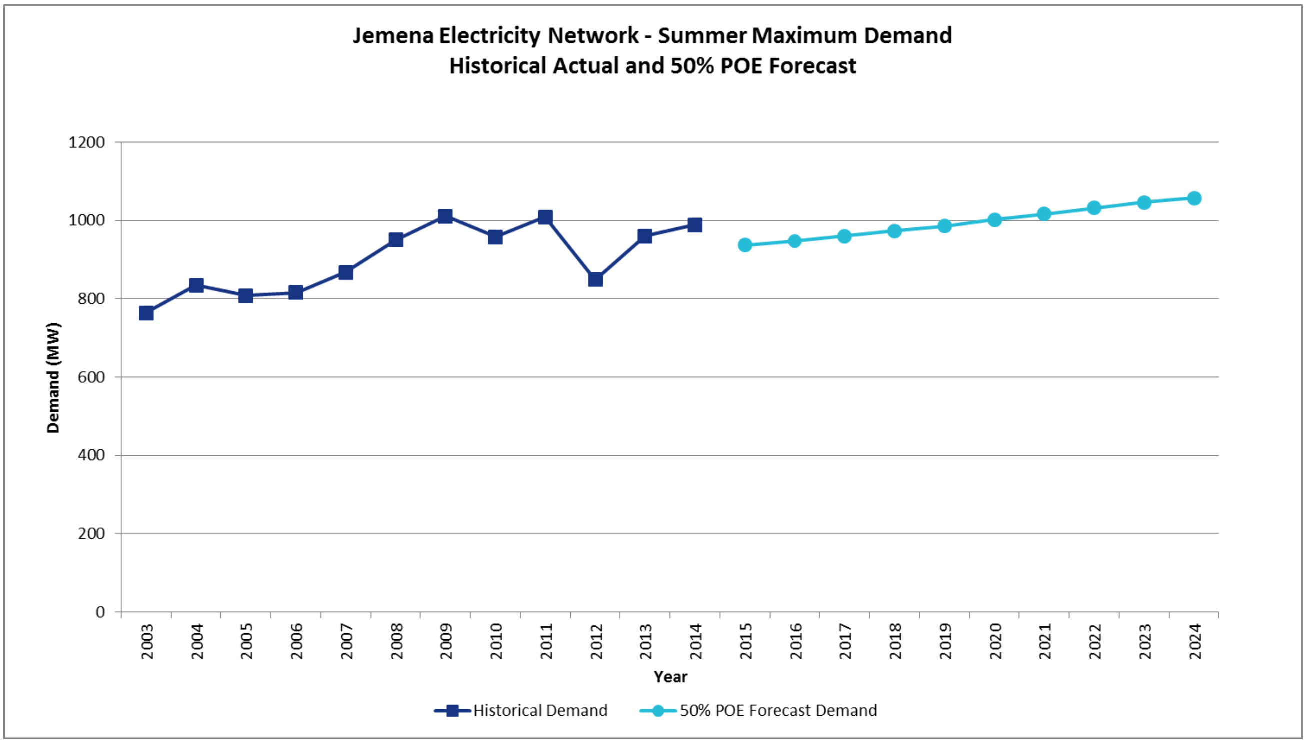
1.2.2 DEMAND FORECASTS AND GRID CHARACTERISTICS

33. JEN recently commissioned a study on electricity demand forecasts, the main findings of which are:

[12] Jemena Electricity Networks – Asset Management Strategy and Objectives

- The network wide maximum demand growth rate is forecast to slow over the next ten years, to an average of 1.35% per annum, compared to the long term average of 2.69% per annum (see Figure 1–1). This slowing growth rate is largely due to energy efficiency technology and solar PV connections offsetting summer demand growth.
- Despite maximum demand growth rate slowing, there are still pockets of significant maximum demand growth that require network augmentation. This growth is driven by urban sprawl in the north of our network and new high-rise residential developments in established inner suburban areas of the network.
- Some areas within the JEN network will experience a decline in maximum demand over the next twenty years, due to large commercial/industrial business closures; the continued impact of solar PV connections and energy efficiency technology and action.

Figure 1–1: JEN peak summer demand (actuals from 2001 to 2014 and forecast from 2015 onwards)

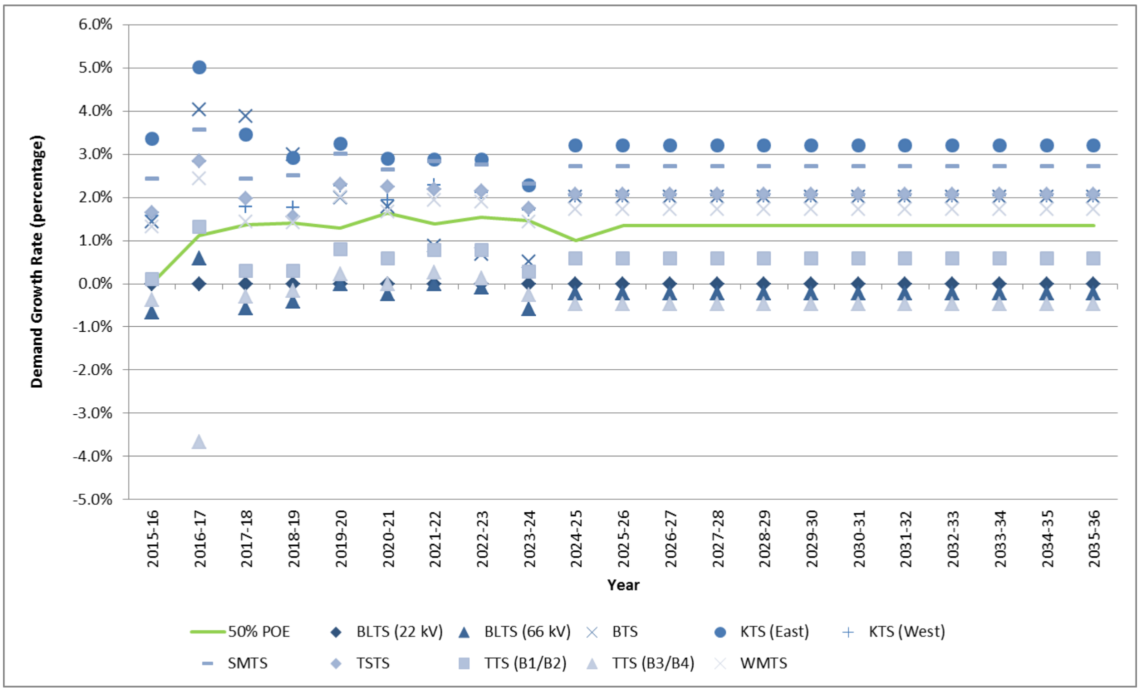


Source: ACIL Allen Consulting, *Jemena Electricity Demand Forecasts Report*, 20 November 2014.

34. Network augmentation expenditure is primarily driven by peak demand growth, as opposed to annual energy growth, and includes localised peak demand growth that does not necessarily occur coincident with the network-wide peak.

35. Figure 1–2 presents the forecast non-coincidental maximum demand growth rate at terminal stations supplying JEN's network, while also showing the network level maximum demand growth rate of 1.35%. This figure shows terminal stations that experience growth in maximum demand, and others that experience a drop in demand. The terminal station maximum demand growth rate forecasts range from +5% to -4%.

Figure 1–2: Non-coincidental demand vs. Aggregate network demand (50% probability of exceedance forecast)



Source: ACIL Allen Consulting, *Jemena Electricity Demand Forecasts Report*, 20 November 2014

36. Despite low aggregated network level maximum demand, augmentation expenditure is still required due to localised network constraints. This presents a challenge as some areas of our network will experience decreasing utilisation levels, making it important to balance expenditure to ensure all our customers achieve a safe, efficient and responsive service.

37. AEMO has forecast[13] increased residential and commercial consumption in Victoria, driven by strong population and income growth (the highest of the NEM regions).

38. Our network is experiencing significant demand growth in the north, due to urban sprawl toward the edge of the urban growth zone. As a result of this urban sprawl and the rezoning of areas to increase urban growth zones, over the next six years we expect to see strong maximum demand growth in areas currently supplied by the zone substations at Somerton (forecast to grow at an average of 5.0% per annum), Sydenham (3.1%), Sunbury (2.6%), and Coolaroo (2.0%).

39. In addition to growth in the urban growth zones, we are also experiencing significant growth in established pockets of the network. This growth is predominately due to the development of high rise residential and office buildings, and the expansion of community facilities and services, such as around Essendon Airport and Melbourne International Airport. As a result, over the next six years we are forecasting high growth in maximum demand for areas currently supplied by the zone substations at Footscray East (forecast to grow at 5.6% per annum), Fairfield (4.0%), Airport West (3.7%), and Coburg South (2.8%) zone substations.

40. Customers are responding to rising retail electricity prices and technological advances by adopting more energy efficient appliances and installing rooftop solar PV to reduce their energy consumption. While this has resulted in a reduction in overall energy consumption, there has been limited impact on peak demand.

[13] AEMO, *National Electricity Forecasting Report for the National Electricity Market*, June 2014

1.3 CUSTOMER ENGAGEMENT

41. JEN must consider and balance the competing interests and preferences of a range of customers, customer groups and other stakeholders, including:

- Households and small, medium and large businesses who are end users of the electricity
- Various consumer advocacy groups and business associations who represent our customers
- Local governments, who are customers of our public lighting services
- Energy retailers, who collect revenue from customers on our behalf.

We must also consider the interests of other stakeholders, including our regulators, the Federal and State Governments, and the Energy and Water Ombudsman.

Our deliberative forum (see Attachment 4-2) involved informing customers about our business and the infrastructure, and services we provide, emphasising the key elements we must consider as we make decisions that have long-term impacts on our customers. Key findings were:

- Although some customers thought that in principle we should strive for continuous improvement (higher service levels over time), the cost of improving supply reliability was considered prohibitive and as a result, there was a strong preference to maintain similar levels of reliability in the future.
- Customers generally support our forward thinking about new and innovative ways to reduce the need for future network investment. When given a choice between increasing investment in ‘poles and wires’ to cater for increased usage on peak demand days, or offering new incentives to consumers to decrease their usage at certain times to avoid the costs associated with building more poles and wires, most participants preferred behaviour change incentives (92%) over increased infrastructure (8%).
- Customers also indicated an interest in future JEN trials exploring ways to better utilise AMI technology for demand management purposes. These include empowering customers with better appliance control and ways to reduce peak time usage through consumer incentives. There was strong support for our proposal to offer various trials to customers to help them reduce their peak usage and associated costs (85% thought this was either completely acceptable or very acceptable).
- There is also support for pricing our services to encourage customers to make more informed (and efficient) decisions about how they use our services and allow us to more efficiently provide services to our customers. Participants felt positive towards us for thinking about ways we can help people save money, and some described the organisation as progressive and flexible.

1.4 DEMAND MANAGEMENT

42. Demand management aims to manage the electricity use profile on a network so as to minimise the cost of supplying customers while maintaining or improving customer options and service levels and is defined by the AER[14] as:

> *“Demand management projects or programs are measures undertaken by a DNSP to meet customer demand by shifting or reducing demand for standard control services through non-*

[14] AER, *Demand Management and Embedded Generation Incentive Scheme, Jemena, CitiPower, Powercor, Ausnet Services and United Energy, 2016-20, 21 November 2014*, Section 3.1.3 – The DMIA criteria, Item 1.

network alternatives, or the management of demand in some other way, rather than increasing supply through network augmentation".

43. Supply costs include costs of augmenting or extending the network as well as electrical losses. Demand management includes initiatives such as: embedded generation; direct load control; distributed storage; tariff options; aggregation and voluntary and curtailable load control.

44. The AEMC defines Demand Side Participation (**DSP**), which includes demand side management as a component as:

> *"an action taken by consumers (either independently or via an intermediary) to manage or reduce their electricity consumption so they deliver a net benefit to the wider market (such as lower costs of supply), that is more than the loss in value or the costs incurred by the consumer."*[15]

45. The mandated rollout of smart meters to essentially all of JEN's customers has provided a solid foundation for demand management. JEN's AMI system provides:

- Information to consumers that allows them to actively manage their energy consumption and for communicating pricing/control information
- Interval energy metering enabling price reflective tariffs to be offered to customers to incentivise behaviours that lead to usage change
- A technology platform whereby the smart meter can interact with an in-home display, energy management system or smart appliance via wireless interface and binding
- Information to JEN to support intelligent demand shaping through direct or indirect load control
- Load limiting (supply capacity control) to maintain network integrity when discretionary load limiting fails.

46. JEN's demand management plan leverages the AMI system and is structured as a portfolio of projects for the evaluation of various demand management methodologies. In preparing the demand management plan JEN recognises that the introduction of demand management in the residential sector is complex, requiring customer engagement and participation. Case studies must therefore form an important part of the demand management plan as they demonstrate and document lessons learnt for customer engagement and participation. The case studies will also document the technology and processes at all levels of power usage and customer size so that the learnings can be applied in developing new models of electricity delivery and implementation.

1.4.1 DEMAND SIDE ENGAGEMENT DOCUMENT

47. The NER sets out the demand side engagement obligations of JEN in that it requires JEN to develop a strategy for engaging with non-network providers. The strategy is to provide for equal weighting to be given to non-network options and traditional network options when considering network solutions and is to be documented in the Demand Side Engagement Document (**DSED**). The DSED is to include the information specified in Schedule 5.9 of the NER and must be reviewed and revised at least once every three years. The revised DSED is to be published on the Jemena website[16] so that parties who have registered their interest in being notified of developments relating to distribution network planning and expansion can be kept up to date. Schedule 5.9 of the NER obliges JEN to describe the process of investigation, development, assessment and reporting of non-network options and the process of engagement and consultation with non-network providers to determine their interest and ability to be involved in the development of non-network solutions.

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15 Australian Energy Market Commission (AEMC), *Power of choice - giving consumers options in the way they use electricity*, Draft Report, 6 September 2012, p 9.

16 http://jemena.com.au/what-we-do/assets/jemena-electricity-network/planning.aspx

1.4.2 OVERVIEW OF DEMAND MANAGEMENT PROJECTS IN 2011-15

Energy Portal

48. JEN's Energy Portal is a demand management initiative designed to enhance electricity consumers' demand management capability and was partially funded through the AER's DMIA for the 2011 regulatory period. By providing better information on electricity usage, consumers are better empowered to choose when and how much energy to consume.

49. JEN's Energy Portal uses AMI technology to provide near real time electricity consumption information. It allows consumers to:

- Know when and how electricity is used in their premises/households
- Make an informed decision about their electricity usage in response to price or other parameters
- Review and develop new energy consumption patterns and set targets.

50. In addition, the Energy Portal allows binding of Home Area Network (**HAN**) appliances to the AMI meter, allowing the consumer to develop a smart home that is energy aware. The new information from the Energy Portal project will offer consumers the knowledge that can translate into actions to shift or reduce their consumption during periods when electricity is priced higher, thus achieving cost savings over time. The scope of the Energy Portal project includes the development and implementation of a secure consumer portal to allow a consumer to register for and receive enhanced services, and an associated consumer awareness program, which are set up to help consumers reduce their electricity consumption.

51. The Energy Portal, implemented as an innovative trial, has been delivered through four phases as follows:

- Design – Detailed design of the solution, including solution architecture, customer portal design and other interfaces (outage and emergency interface design)
- Build and test – Development and testing of the consumer portal and other interfaces including deployment of new hardware and new software, end user training and handover documentation
- Customer awareness – Development and ramp up of the AMI customer awareness program
- Deploy and support – Cutover of the new Energy Portal and other interfaces and four weeks post implementation support.

52. The development of the Energy Portal was completed in the last quarter of 2011 and initial trials commenced in December 2011 among a selected consumer group. JEN launched its Energy Portal to customers in June 2012.

53. Subsequently, JEN implemented of a number of enhancements to the Energy Portal. More specifically, the enhancement works covered:

- New capabilities to deliver basic HAN diagnostics and an IHD test environment for In Home Display (**IHD**) vendors
- Estimates of the consumer's electricity consumption in terms of carbon emissions
- A community portal; provision to councils and community groups of anonymous aggregated consumption data
- Improved security with the removal of all personal identifiable data.

JEN provided community demonstrations of the Energy Portal as well as attended retailer briefings to get a wide stakeholder feedback. A Community Online Communications Advisor was engaged in 2013 and 2014 to:

- Increase community connectivity by managing and enhancing JEN's digital reach, developing and managing marketing materials and promoting the benefits of the Energy Portal and the AMI technology
- Support demand management objectives of the business by developing questionnaires, carrying out surveys and analysing customers' behaviour.

Energy Portal for Demand Management Study[17]

54. This pilot study analyses the outcomes of electricity consumers who have registered for the energy portal on an opt-in basis within the JEN network and have a remotely read smart meter (AMI meter). The electricity outlook demand management pilot study underpins the measurement and control parameters for a medium and long term Electricity Outlook Demand Management Study (**EODMS**).

55. The objectives include:

- Establish a measurement methodology for a statistically significant sample group/s of electricity consumers who are actively participating in the Electricity Portal
- Effectively isolate societal, political and commercial factors from the sample group – using a control reference group of equal size and demographic to that of the study group/s
- Measure consumer behavioural changes in the short term and establish a baseline for a long term study to assess sustainable behavioural outcomes for changes in peak demand, daily load factor, consumption and generation
- Engage with consumer groups and assess customer engagement and identify Electricity Portal impacts, benefits, shortcomings, recommendations and opportunities
- Forecast the number of customers that are likely to be active ongoing users of the Electricity Portal – a distributor delivered portal in a contestable retail market
- Quantify foregone revenue lost as a consequence of consumer portal participation.

56. Some of the positive outcomes from the pilot study were

- Customer Portal served as an educative tool for customers who are concerned about their electricity usage. The portal data provided sufficient information to understand their usage pattern to help manage consumption
- The study clearly showed that regular portal customers (super active, active and normal) reduced their daily peak demand compared to their counterparts in the control group
- A considerable reduction in peak-peak demand was observed among portal customers The study shows that customers who are more concerned about their electricity usage have a higher tendency to look for alternative technology e.g. install solar panels. This is clearly visible from the higher penetration of solar customers among our portal customers compared to whole of JEN.

[17] This study was not funded under the AER's DMIA for 2011-15.

Demand Response Trial – Phase 1[18]

57. JEN has initiated a Demand Response Field Trial (**DRFT**) project to develop our understanding of the benefits, costs, pricing/commercial arrangements and operational structures of targeted demand response programs. Phase 1 of the trial includes model development and desktop analysis and is close to completion.

58. The key deliverables for the phase 1 trial are;

- Assessment of the amount of demand response available by surveying the customers within the proposed emerging constraint study area, negotiate with customers and prepare costing for each available demand response sites
- Development of an end-to-end operating model for each proposed demand response solution, including options for pre- and post-contingency response, notice period, sales, contracting of load, site monitoring installations, dispatch operations, verification and settlements and implementation timeline
- Development of a pricing model for demand response solutions in general including pricing points for different classes of customers. The pricing model shall be developed in a form that JEN can iterate and use to determine pricing for different customer classifications in future pricing assessment of demand response solutions. The pricing model will be built around each MVA of the load mitigated on a sub transmission line and/or associated zone substations
- Development and provision of a pricing schedule for the proposed solutions for the emerging constrain study area, including management and customer payments options for different notice periods, opt-in (non-firm) verses fully automated (firm) contracts.

59. Phase 2 of the trial is proposed to be undertaken in 2016 and 2017. The objectives and scope of phase 2 are described in Section 3.3.6.

[18] This phase 1 trial is intended to be funded under the AER's DMIA for 2011-15.

2. INNOVATION AND CHANGE

60. With the increasing penetration of distributed energy resources in electricity grids, the traditional 'top-down' one way flow structure of electricity supply is changing to a more multi directional flow. Instead of just consuming electricity, customers can and do produce electricity, thus either lowering their demand or supplying their excess production back to the grid. At the same time, with the advent of new technology and AMI, more information is available that facilitates greater control over consumption patterns.

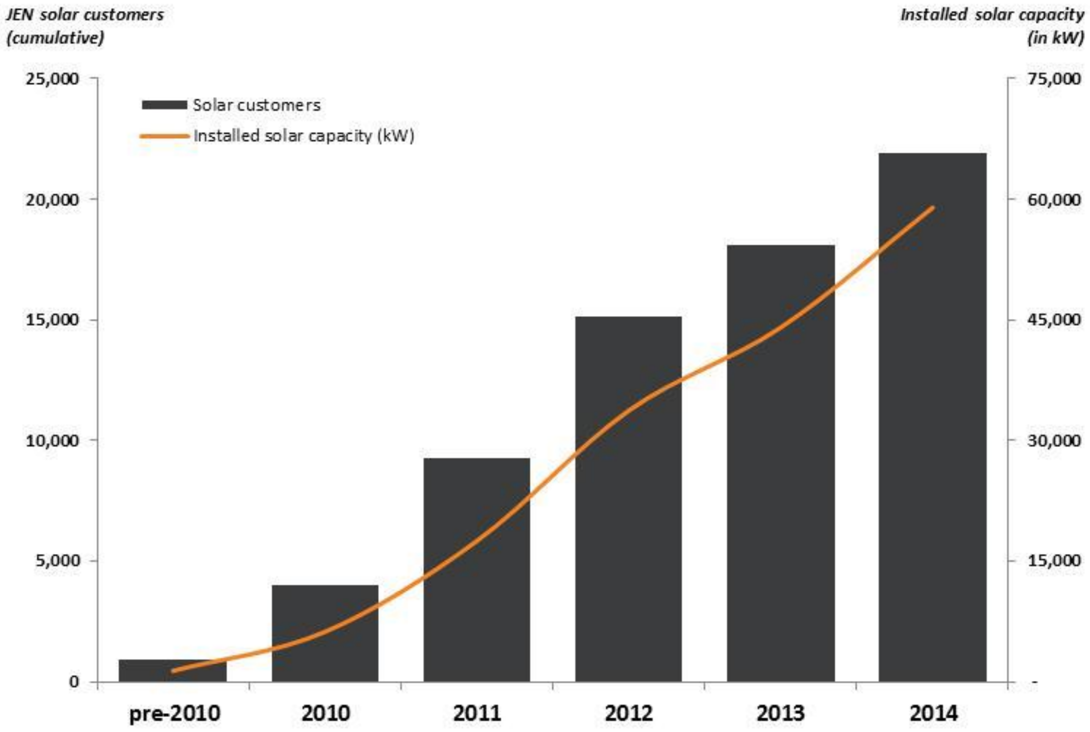
61. In this evolving market, generation is dispersed across the network rather than being centralised and controllable. New constraints are therefore emerging on distribution networks, which had been designed for unidirectional flow. Balancing new sources of supply, such as intermittent PV, small scale wind and gas fired Combined Heat and Power (**CHP**) systems, with more intelligent usage such as energy consumption monitoring and control, demand pooling and storage is becoming increasingly important[19]. The role of the traditional DNSP is unclear in this changing landscape, but it is clear that there is a need for them to understand these emerging issues and position themselves to add value to all in the electricity marketplace.

2.1 EMBEDDED GENERATION

62. JEN has seen significant distributed generation growth on our network over the past five years in terms of both numbers and total capacity. To date this growth has predominantly occurred in the form of micro embedded generators such as from solar PV generators. From 2010 to 2012, significant capital and production subsidies were available to promote the uptake of PV. Figure 2–1 shows the growth of installed rooftop PV in megawatts in our network over the period 2009 to 2014.

[19] Nillesen, Paul, Pollitt, Michael, and Witteler, Eva, New Utility Business Model, , Distributed generation and its implications for the utility industry, First edition

Figure 2–1: The growth in solar small-scale PV capacity in our network (2009 to 2014)



63. From 2009–2014, we have seen the cost of installing rooftop PV systems ($/kW) decline from approximately $8,000 - $10,000 per kW installed in 2009 to approximately $2,000 - $3,000 per kW (inclusive of small scale technology certificates) installed in 2014.

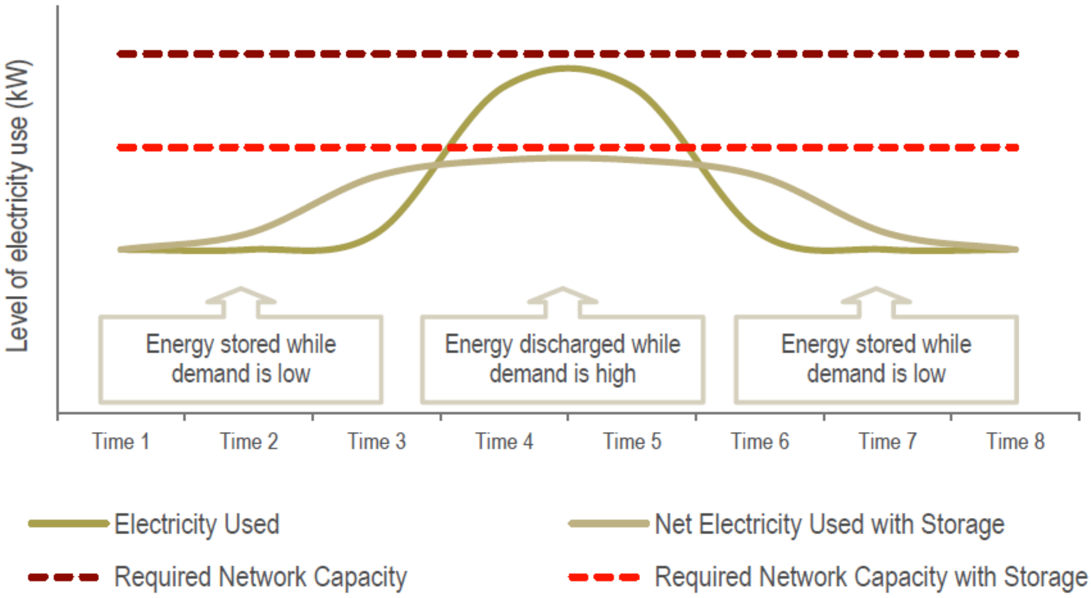
64. CHP or Combined Cooling, Heat and Power (**CCHP** or tri-generation) is another type of embedded generator technology that is experiencing increasing uptake in the JEN network. This type of technology is typically deployed by large industrial or commercial customers – airports, hospitals, community swimming pools, large building complexes etc.

2.2 ENERGY STORAGE

65. Over the past few years, there have been significant advances in energy storage technologies. The technology costs are decreasing rapidly and around the world there is increased uptake of storage solutions for specific applications. However, it is still an emerging technology, and we have not seen any significant development involving this technology within the JEN network. Cost is still an impediment to widespread uptake of solutions and applications it is used for have to be well defined and specific enough to put forth a positive business case.

66. From a network perspective, grid based energy storage is likely to emerge as a legitimate alternative to more conventional network augmentation works. In capacity constrained parts of the network and especially when growth in demand is low to moderate, a grid storage solution offers a scalable alternative that can be sized to meet the magnitude of the constraint. Provided the costs can be justified, energy storage can be used as a mechanism to shift demand from peak to off peak.

Figure 2–2: Peak shifting using grid energy storage



Source: Marchment Hill Consulting, '*Energy Storage in Australia*', 2November 2012

67. Plug-in hybrid electric vehicles are moving closer to commercial viability, although the market has not yet fully adopted this technology, with only 64,000 vehicles (mainly hybrids)[20] being sold in Australia between 2005 and 2013. This is less than 1% of new light vehicle sales over this period. Lower petrol and gas prices have also dampened the technology's immediate prospect, but a shift in prices could change this situation.

68. The dual purpose of electric vehicles for transport and as a source of income for electricity storage and supply could make plug-in electric vehicles an attractive storage technology. While uptake rates are an important consideration for planning to adapt to this emerging load, the clustering and timing of electric vehicle charging is more important because it will directly impact the performance and utilisation of the network in specific locations.

2.3 ADVANCED METERING INFRASTRUCTURE

69. AMI is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between us and our customers.

70. At a jurisdictional level, in 2006, the Victorian Government mandated a full roll out of AMI to small business and residential customers. The decision to mandate the roll out of AMI led to considerable investment in Victoria in smart metering infrastructure and the telecommunications systems that support it. This infrastructure is instrumental in implementing efficient demand management tools and methodologies that facilitate the efficient application of DSP. This year, we have successfully completed the deployment of smart meters to 98% of our less than 160 megawatt-hour per year customers. This changes the way we are delivering services to and engaging with our customers, and planning and operating the network.

71. The following services are now provisioned remotely, improving the efficiency of service delivery:

[20] Reference: Federal Chamber of Automotive Industries, VFACTS annualised data 2005–2013, Canberra

- Remote meter reading
- Re-energisation/de-energisation (for example, when customers move house)
- Remote meter re-configuration (for example, when customers switch to a solar tariff)
- Special meter reads

72. While we are still in the early stages of realising benefits from AMI, there are many features that have the potential to provide additional customer benefits. Key features include real-time reporting of supply outage and restoration by smart meters to the Outage Management System enabling faster fault detection and restoration; customer supply quality monitoring, enabling pro-active detection and rectification of degraded services; and direct or indirect load control to support demand-side responses. The AMI system will support the projects outlined in this document by providing granular data (such as energy consumption, distributed generation output, power quality) to pinpoint trial locations, and deployment of features such as time-of-use tariff and direct load control. In leveraging the AMI functions and features, JEN has assumed that meter contestability will have no adverse effect on access to the many function-rich network functions currently available in the AMI system. If these functions and services are not available in a contestable metering environment then additional funds from within the DMEGCIS scheme may be necessary to deliver future innovations.

2.4 ENERGY EFFICIENCY

73. Installations of energy efficient lighting (including street lights), efficient appliances and equipment, and adoption of energy efficiency practices can all reduce energy use and therefore reduce constraints on our network while saving our customers money.

74. Technologies such as variable speed drives, load control, and waste energy capture and reuse (such as co/tri-generation) offer opportunities for energy efficiency for industrial customers. Efficient motors and compressors also have the potential to significantly reduce energy consumption[21]. The majority of savings across all energy types and industry sectors included operational process improvements (67%), and capital upgrades (33%).

75. Energy efficiency and smart appliances have seen advances in development over the last ten years, and are likely to continue to develop over the next 20 years. Energy productivity improvements can come from more energy efficient buildings, improved processes or equipment in manufacturing, improved transport, and better knowledge and management of energy. Refrigerators today use less than two thirds of the energy of those made 20 years ago, and they are bigger, better and no more expensive than the old ones.

76. The recent advent of major industry players, such as Google (thermostat) and Apple (home management system) into the electricity field suggest that we may experience widespread deployment of smart devices and integrated phone management systems in the home.

77. More energy efficient appliances and buildings will be introduced and will have a progressive impact on demand and especially energy consumption levels.

2.5 DEMAND RESPONSE

78. Demand response is a particular type of demand management initiative comprised of contracted load reduction either controlled by customers or by the network through direct load control. When deployed for mitigating

21 The IEA estimates industrial energy savings potential as around 20 per cent in the five most energy intensive industries if they applied the best available technologies.

capacity constraints within the network, demand response can be effective in achieving peak load reduction. Customers can be contracted to voluntarily reduce their demand on specific direction from the network and in return these contracted participants would be eligible for capacity and performance payments.

79. Demand response can include targeted incentives, technologies and customer education programs directed towards reducing or changing patterns of energy use.

80. **Customer controlled demand response** programs typically involve an aggregation component that includes customer acquisition, contracting, technology deployment, performance testing and settlements. The DNSP would have control over operations and dispatch and have the ability to call a demand response event when the network conditions require a reduction in load – either during times of high network load or during outage conditions.

81. **Distributor controlled demand response** programs have a larger technology component and rely on the deployment of advanced metering and communications infrastructure. The customers participating in the program also need to have loads such as air conditioners or refrigerators that can communicate with the DNSP's IT system and are enabled for direct load control.

82. In the current environment, foundations for an effective and vibrant demand response marketplace are beginning to emerge. In our view, the following are the key drivers;

- There are strong signals from a policy and regulatory perspectives which are incentivising an uptake in demand side participation and demand response
- AEMC's Power of Choice review[22] final report includes specific recommendations to establish a market based demand response mechanism that allows consumers, or third parties acting on consumers' behalf, to directly participate in
- Customers, especially larger commercial and industrial customers, are seeing increasing value in managing their electricity consumption by implementing flexible business and manufacturing processes, if it results in financial savings or possible new revenue.

2.6 PRICING

83. JEN's network pricing strategy determines the detail of how JEN recovers from its customers the costs of running and investing in the shared electricity network. JEN's current price structures differ between customer classes. Residential and small commercial customers pay a combination of fixed (per day) and variable (per kWh consumed) fees. In some cases, the variable fee includes a time-of-use component—with a higher tariff applying during peak times. In addition to those two components, large commercial customers also pay a demand charge (per kW of the customer's maximum demand).

84. In the coming years, we expect a number of trends to impact the cost base we need to recover and the granularity of those costs (the breakdown of which customers cause which costs):

- More and more customers will use the network for two-way energy flows—exporting electricity that they generate, as well as importing electricity to consume. These two-way customers are likely to impose more costs on the network than current typical customers. Yet these two-way customers will also consume much less energy per annum from the distribution network, reducing the variable charge part of their bill.

[22] AEMC (Australian Energy Market Commission) Power of choice review – giving consumers options in the way they use electricity, Final Report, 30 November 2012

- The probability of customers disconnecting from the distribution network entirely, or simply using the network as a back-up will increase, as economics of micro-generation and storage technology continues to improve. This could be due to customer-driven changes in behaviour, or due to head on competition from generator-retailers offering integrated retail, micro-generation and storage offerings.
- Customers that remain as pure consumers of energy through the distribution network are likely to continue to reduce their kWh annual usage, while their individual maximum demand (and the strain they place on the network) will largely remain unchanged, or decline at a lower rate than energy use.

85. In this changing environment, it will be vital for JEN to ensure that the tariffs charged to individual customers reflect the costs of JEN providing network services to those customers as far as possible (see Attachment 10-1).

3. PROPOSED PROJECTS UNDER 2016-20 DMEGCIS

3.1 DEMAND MANAGEMENT INCENTIVE SCHEME

3.1.1 OBJECTIVES OF THE DMIS[23] (DMEGCIS[24])

86. The National Electricity Rules (**NER**) require the AER to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to building more network solutions.[25] To meet this requirement, and motivated by the need to improve the five Victorian electricity distributors' capability in the demand management area, the AER is proposing to implement a DMIS in the distribution determinations for the current regulatory period.

87. The DMIS is designed to complement the broader regulatory framework in providing incentives for DNSPs to trial innovative non-network alternatives for managing expected demand for standard control services. It supplements a DNSP's approved capital and operating expenditure, to facilitate investigation and implementation of demand management strategies.

88. Paraphrasing the AER[26], demand management projects or programs may be: broad-based, which aim to reduce demand for standard control services across a DNSP's network, and/or specific, which aim to address specific network constraints at the location and time of the constraint. They may be innovative, and designed to build demand management capability and capacity and explore potentially efficient demand management mechanisms, including but not limited to new or original concepts and be tariff or non-tariff based.

3.1.2 DMIA CRITERIA

89. Projects and programs for which approval is sought under the Demand Management Incentive Scheme (**DMIS**) are to meet the DMIA criteria[27]. The criteria states –

1. Demand management projects or programs are measures undertaken by a DNSP to meet customer demand by shifting or reducing demand for standard control services through non-network alternatives, or the management of demand in ways other than increasing supply through network augmentation.
2. Demand management projects or programs may be:
   a) broad-based demand management projects or programs
   b) peak demand management projects or programs.
3. Demand management projects or programs may be innovative, and designed to build demand management capability and capacity and explore potentially efficient demand management mechanisms, including but not limited to new or original concepts.

23 AER (, *Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016, 24 October 2014, Section 3.4 – Demand Management Incentive Scheme (DMIS)*, p77.

24 ibid, Footnote 275 "The rules have since changed the name to 'Demand Management and Embedded Generation Connection Incentive Scheme' (DMEGCIS) to explicitly cover innovation with respect to the connection of embedded generation. Our current and proposed DMIS include embedded generation. We consider embedded generation to be one means of demand management, as it typically decreases demand for power drawn from a distribution network".

25 NER, clause 6.6.3(a).

26 ibid, Section 3.1.3 – the DMIA criteria, Items 2, 3 & 4.

27 AER, *Demand Management Incentive Scheme, Jemena, CitiPower, Powercor, S P AusNet and United Energy, 2016-20*, November 2014.

4. Recoverable projects and programs may be tariff or non-tariff based.

5. Costs recovered under this scheme:

    a) must not be recoverable under any other jurisdictional incentive scheme

    b) must not be recoverable under any other State or Commonwealth Government scheme

    c) must not be included in forecast capital or operating expenditure approved in the distribution determination for the regulatory control period under which the scheme applies, or under any other incentive scheme in that determination.

6. Expenditure under the DMIA can be in the nature of capital or operating expenditure. The AER considers that capex payments made under the DMIA could be treated as capital contributions under cl. 6.21.1 of the NER and therefore not rolled into the regulatory asset base (**RAB**) at the start of the next regulatory control period, however the AER's decision in that regard will only be made as part of the next distribution determination.

3.1.3 AER'S ASSESSMENT APPROACH

90. The AER has to consider several factors in developing and implementing a DMIS for the Victorian distributors.[28] These are:[29]

- **Benefits to consumers** likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme and customers are willing to pay for increases in costs resulting from implementing a DMIS

- **Balanced incentives -** the effect of a particular control mechanism on a distributor's incentives to adopt or implement efficient non-network alternatives; the effect of classification of services on a distributor's incentive to adopt or implement efficient embedded generator connections; the extent the distributor is able to offer efficient pricing structures; and the possible interactions between a DMIS and the other incentive schemes.

3.1.4 REPORTING REQUIREMENTS

91. The DNSP is required to submit an annual report on its expenditure under the DMIA for each regulatory year of the regulatory control period. The information provided will form the basis of the AER's assessment of the DNSP's compliance with the DMIA criteria, and its entitlement to recover expenditure under the DMIA.

3.2 DEMAND MANAGEMENT OBJECTIVE

92. JEN classifies demand management solutions as non-network solutions that do not involve building of traditional network assets (poles and wires). These include, but are not limited to:

- Tariff offerings (e.g. time of use, critical peak pricing)

- Demand response (contracted load reduction either initiated by customers or by the DNSP through direct load control)

[28] NER, clause 6.6.3(b).

[29] AER, *Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016, 24 October 2014, Section 3.4 – Demand Management Incentive Scheme (DMIS)*, p115.

- Embedded generation
- Energy storage and subsequent release at peak times (including electric vehicles fitted with vehicle-to-grid technology)
- Energy efficiency incentive programs.

93. Our objectives over the next five years for demand management are to:

- Develop options and flexibility for both our network and our customers through the application of demand management solutions
- Establish policy, systems and processes that support demand management
- Where economical, resolve network supply quality and capacity constraints using demand management.

All of this goes towards creating a sustainable network of the future, capable of meeting the changing needs of our customers.

3.3 PROJECT PROPOSALS

94. In order to meet our demand management objectives (see Section 3.2), JEN is seeking approval of the following projects under the DMEGCIS for the 2016 regulatory period:

1. **Efficient connection of micro-embedded generators**
   Maximizing the capacity of Low Voltage networks for efficient connection of inverter based micro-embedded generators
2. **Direct load control trial**
   Direct control of customer appliance utilising AMI
3. **Managing peak demand through customer engagement**
   Empowering customers to make informed decisions through education, incentives and analytics
4. **Technology and economic assessment of residential energy storage**
   Evaluate technical and economic viability of residential scale energy storage solutions when deployed in conjunction with rooftop solar PV systems
5. **Distributed grid energy storage**
   Storage solutions to mitigate network capacity constraints and maintain quality of electricity supply
6. **Demand response field trial – phase 2**
   Follow on from the desktop models developed in 2014, this phase 2 aims to understand practical issues associated with dispatch and control of demand response

95. These overall objectives of these proposed projects are in agreement with the AER’s DMIA criteria.

96. The sections below describe for each trial the objectives, expected scope of work, benefits and how they relate to the DMIA criteria, project implementation and expected costs. The project costs and timing of these costs are provided in Section 3.4. Detailed trial schedules are provided in **Attachment A**.

3.3.1 EFFICIENT CONNECTION OF MICRO EMBEDDED GENERATORS

Objective

97. To analyse the constraints that limit the ability of LV networks to host micro-embedded generators such as rooftop solar PV and trial technical solutions to alleviate such constraints.

Problem statement

98. JEN currently has a standardised process for the connection of inverter based generators that are less than 10 kW for single phase systems and less than 30 kW for three phase systems. The connecting generators are required to meet the installation, inverter and grid protection requirements of 'Australian Standard AS4777 - Grid connection of energy systems via inverters' to satisfy JEN's automatic connection guideline. Inverter based generators that are greater than these size thresholds are assessed on a case by case basis and follow the connection criteria in the NER and other applicable jurisdictional instruments.

99. As the penetration of micro embedded generators such as PV has increased, voltage regulation, power quality and protection coordination issues have emerged that limit the connection capacity of LV feeder circuits. For example, a high concentration of rooftop PVs on an LV feeder circuit could impact the voltage profile and tap positions of the distribution transformers. If left unchecked this could result in inadvertent tripping of the generators or worse, cause protection mis-operations at the feeder level.

Project expectations and identifiable benefits

100. Employing both desktop technical analysis and field work this trial aims to:

- Identify distribution network constraints that limit the effective connection of micro embedded generators
- Investigate and field test innovative technologies and operational solutions that allow for increased hosting capability of micro embedded generators
- Develop/recommend policies, processes and tools for managing the connection of inverter based embedded generators
- Provide insight to optimise the design of the network to best mange the changed peak demand and bi-directional energy flows.

101. Benefits will flow from the identification of technical problems and their solution to the issues presented by the increased penetration of micro-embedded generators connecting to LV feeders. It is expected that the project outcomes will provide important learnings that will facilitate the seamless automatic integration of embedded micro-embedded generators into the JEN network. Furthermore, a location specific size limit will allow customers and JEN to safely connect rooftop solar PV and other inverter based generation, while maintaining a reliable and secure distribution network. . These outcomes are in compliance with DMEGCIS criteria.

Compliance with DMIA criteria

102. Section 3.1.3 of the AER's DMEGCIS for JEN[30] states that programs and projects need to meet the DMIA criteria in order to be eligible for approval under the DMIS. This trial project complies with the DMIA criteria as follows:

[30] AER, *Demand Management and Embedded Generation Incentive Scheme, Jemena, CitiPower, Powercor, Ausnet Services and United Energy*, 2016-20, 21 November 2014

- The project is aimed at developing technical solutions for the increased uptake of micro-embedded generation and thereby reducing demand for standard control services, rather than increasing supply capacity through network augmentation.
- The project is a broad based demand management initiative which aims to reduce demand for standard control services across the JEN network. This project is targeted towards customers who are or will be owners of micro-embedded generators such as rooftop solar PV.
- The project deliverables are to investigate technical barriers and formulate solutions for the increased uptake of embedded generation as an efficient demand management solution.
- The project is a non-tariff based project.
- The project cost will not be recovered under any other jurisdictional incentive scheme or State or Commonwealth Government scheme, and have not been included in forecast capital or operating expenditure proposal for the 2016 regulatory control period.
- The nature of expenditure is a combination of capital and operating expenditure.

High level scope of work

<u>Task 1 – Site selection, installation and baseline testing</u>

103. An appropriate LV feeder within the JEN network will be selected to ensure that the field results are representative of the network. The site will need to comply with all applicable regulations for a trial of this nature as well as providing unrestricted access to JEN engineers and service delivery personnel. A suitable feeder location on the network should be able to incorporate a minimum micro embedded generator size of 30 kW scalable to 100 kW

104. A solar PV generating system of minimum 30 KW and scalable to up to 100 KW will be procured and installed at this site. Appropriate measuring devices that can monitor and record variations in current, voltage, harmonics, etc., will be installed. Thereafter unit testing of micro embedded generators of 30 kW will be undertaken followed by measuring and recording the system events on the feeder for a minimum period of three months.

<u>Task 2 – Modelling and simulations</u>

105. Drawing on the recorded data, a simulation model of the PV system installation will be developed and integrated with an appropriate simulation software platform. Technology and operational solutions to allow increased hosting capability of micro embedded generators will be formulated and field testing of these solutions will be undertaken.

<u>Task 3 – Field trial of solutions</u>

106. The size of the generating system is to be increased in increments of 10 KW and baseline unit testing employed in Task 1 is repeated with the preferred solution(s). After the unit testing program has been completed, measuring and recording system events for a period of at least one month will take place. Field testing results will then be benchmarked against the baseline to determine any potential improvements in the automatic connection limits for micro-embedded generators in JEN's network.

107. The field trial will then be extended to a select number of customer locations (three to four) within the JEN network. It should be noted that through the customer consultation process as part of the 2016 regulatory process, many JEN customers with large PV installations are interested to participate in such a field trial. The solutions developed will be trialled with consideration of the specific local network characteristics. The sites will be monitored for a limited period determine the integrity of the solutions and get customer feedback.

Task 4 – Develop tools and processes

108. The desktop analysis conducted in Task 2 and the results from the field trials in Task 3 will form the basis for developing system tools for a location specific automatic connection limit for connection of inverter based micro-embedded generation to JEN's LV network. Business processes will be updated where necessary that will facilitate a simplified and streamlined experience for customers.

Task 5 – Reporting and recommendations

109. During the trial, quarterly progress reports will be prepared and issued documenting:

- Key equipment installed
- Testing carried out
- Analysis performed
- Costs incurred
- Status to date.

110. This will provide the material for a case study to be documented detailing the technical constraints and potential solutions to accommodating an increased penetration of micro embedded generating installations on LV feeders in the network.

Implementation costs

111. The expected implementation costs associated with this project comprise $764,800 to be expended over a period of 24 months from Q3, 2018 to Q2, 2020.

112. The cost of the trial has been determined based on market rates for solar PV panels, associated auxiliary equipment and other plant to be trialled and tested. The expenses related to construction, project management and engineering analysis are also included as cost components.

3.3.2 DIRECT LOAD CONTROL TRIAL

Objective

113. To investigate technologies and associated processes for direct load control of customer equipment to shift demand from 'peak' to 'off peak' times, while ensuring that customers' utility and comfort levels are not compromised.

Problem statement

114. As discussed in Section 1.2.2, over the past decade there has been an increasing divergence between the average demand and the peak demand in Victoria. Network augmentation expenditure is primarily driven by peak demand growth, as opposed to annual energy growth, including localised peak demand growth that does not necessarily occur coincident with the network-wide peak. Despite low aggregated network level maximum demand forecasted over the next ten years (see Figure 1–1), augmentation expenditure is still required due to localised network constraints. This presents a challenge as some areas of our network will experience decreasing utilisation levels, making it important to balance expenditure to ensure all our customers achieve a safe, efficient and responsive service.

115. The AMI rollout in Victoria saw the installation of smart meters with two way communications capability to the majority of households and small businesses across the state. This opens up new opportunities for actively

monitoring and controlling, in real time, the electricity supply to every end user, which is crucial for ensuring improved reliability and quality of supply. Demand management solutions that leverage AMI technologies such as direct load control (**DLC**) that shift discretionary demand to off peak periods are seen as possible solutions. However technology deployment, customer processes and business implications of DLC for managing peak demand has not been adequately examined and analysed.

Project expectations and identifiable benefits

116. The aim of this project is to develop direct load control as a credible demand management alternative to substitute or defer network augmentation works by:

- Developing technical capabilities and an in depth understanding of the control and communications technologies for DLC
- Developing customer and business processes for managing a DLC dispatch program
- Undertaking a limited marketing campaign to enrol voluntary participants for a field trial that offers both educational and financial incentives
- Trialling technologies and processes for a limited number of participants
- Leveraging AMI and data analytics to enable and inform on the benefits and limitations of the DLC techniques on a scaled up rollout.

117. It is expected that at the conclusion of the trial, algorithms and processes developed and measures adopted will have the potential of reducing peak demand on a scaled up rollout, thus possibly deferring more expensive network augmentation works. The project outcomes will facilitate the development of credible demand management solutions to the problem of peak loading on localised constrained assets, thereby reducing the need for augmenting standard control services. These outcomes are in line with the AER's DMEGCIS criteria.

Compliance with DMIA criteria

Section 3.1.3 of the AER's DMEGCIS for JEN states that programs and projects need to meet the DMIA criteria in order to be eligible for approval under the DMIS. This trial project complies with the DMIA criteria as follows:

- The project is aimed at investigating technologies and associated processes for direct load control of customer equipment to shift demand from 'peak' to 'off peak' times and thereby reducing demand for standard control services, rather than increasing supply capacity through network augmentation.
- The project is a broad based demand management initiative which aims to reduce demand for standard control services across the JEN network.
- The project deliverables are to investigate direct load control through smart meter infrastructure as an efficient demand management solution.
- The project is a tariff based project.
- The project cost will not be recovered under any other jurisdictional incentive scheme or State or Commonwealth Government scheme, and have not been included in forecast capital or operating expenditure proposal for the 2016 regulatory period.
- The nature of expenditure is a combination of capital and operating expenditure.

High level scope of work

Task 1 – Marketing and customer enrolment

118. As a first step, activities to design an appropriate tariff structure will be commenced and customer survey undertaken to educate and inform the tariff design process.

119. A marketing campaign will be designed for enrolling participants in a field trial that includes both educational materials and structured financial incentives to motivate customers to join. Having designed the marketing campaign and identified a suitable pool of participants the next step is to embark on a campaign of customer engagement and participation. Finally participants will be accepted, contracted and inducted into the trial.

Task 2 – Process development

120. Thereafter work will be undertaken to develop customer and business processes for the effective implementation of DLC that includes: customer engagement and enrolment procedures; and development of applicable tariffs, contracts and commercial arrangements. DLC dispatch programs together with back office systems that will capture and analyse data will then be formulated.

Task 3 – DLC field trial

121. A list of materials and appliances, for example demand response enabling devices (**DRED)** will be drawn up and procured. DREDs will be retrofitted to older appliances while the connection of newer smart appliances will be established with the smart meter infrastructure.

122. Thereafter, on days that meet the DLC deployment criteria, DLC will be activated and full functional tests performed. Raw data will be collected at the customer level, the distribution transformer level, and zone sub-station level. With this data, advanced data analytics will be performed to understand the efficacy of DLC, draw conclusions and develop recommendations for future implementation of DLC dispatch.

Task 4 – Reporting and recommendations

123. During the trial, quarterly progress reports will be prepared and issued documenting:

- Key equipment installed;
- Testing performed;
- Costs incurred; and
- Status to date.

124. This will provide the material for detailed a case study to be documented detailing all the matters to do with the implementation, delivery and lessons learnt from the trial.

Implementation costs

125. Costs of implementing this project comprise $1,034,400 to be expended over a period of 27 months from Q3, 2017 to Q3, 2019.

3.3.3 MANAGING PEAK DEMAND THROUGH CUSTOMER ENGAGEMENT

Objective

126. To investigate the benefits and associated process changes required to empower customers with a higher degree of control in managing their demand during system peaks.

Problem statement

127. As discussed in Section 1.1.2, AEMC's Power of choice review confirmed that demand management benefits consumers and suppliers only if a new and different level of interaction between the parties is put in place. Added to this, debates in recent years to the present time on the efficacy of smart meters and electricity prices has given the community a much enhanced appreciation of how their behaviour impacts on electricity prices. Getting community support and involvement is therefore vital to the successful application of demand side management.

128. JEN has therefore developed strategies aimed at consolidating this heightened understanding between the parties through the mechanism of ongoing communication campaigns, which inform on and highlight the benefits of demand side management and DSP. Central to this approach has been the ongoing collaboration with relevant stakeholders, such as local government, developers, building and building service designers and community groups.

129. While the impact of the above methods in reducing overall energy consumption is well understood, distribution businesses need to gain better understanding on the impact on reducing peak demand. It is possible that certain incentive mechanisms and tariff structures are more effective than others in this respect.

Project expectations and identifiable benefits

130. For this trial, a customer engagement campaign will be undertaken aimed at informing and educating customers and stakeholders. It will include trialling innovative incentives for customers to motivate them in managing their demand during network peaks in order to gain the fullest advantage of the benefits on offer.

131. This trial therefore aims to:

- Develop and implement a cohesive customer engagement strategy comprising customer education, innovative tariffs and data analytics
- Develop an education program that increases awareness among different classes of customers on peak demand reduction possibly utilising IHDs, home energy management analysis, enhanced web portal etc.
- Design and undertake a tariff trial aimed at managing peak demand
- Leverage smart meters and data analytics to inform on the benefits and limitations of demand management.

132. Customer education and a regime of incentives and disincentives have a definite role to play in reducing peak demand and thereby augmentation works to support higher network capacity. The trial outcomes would help identify tools, methods and techniques that can best assist in incentivizing customers to manage their demand and lowering their energy consumption. These outcomes are in line with the AER's DMEGCIS criteria.

Compliance with DMIA criteria

Section 3.1.3 of the AER's DMEGCIS for JEN states that programs and projects need to meet the DMIA criteria in order to be eligible for approval under the DMIS. This trial project complies with the DMIA criteria as follows:

- The project aims to investigate the benefits and associated process changes required to empower customers with a higher degree of control in managing their demand. As such the project will help reduce demand for standard control services, rather than increasing supply capacity through network augmentation.
- The project is a broad based demand management initiative which aims to reduce demand for standard control services across the JEN network. This project is targeted towards residential customers.
- The project deliverables are to develop capabilities in tariff based and energy efficiency based programs as an efficient demand management solution.
- The project is a tariff based project.
- The project cost will not be recovered under any other jurisdictional incentive scheme or State or Commonwealth Government scheme, and have not been included in forecast capital or operating expenditure proposal for the 2016 regulatory period.
- The nature of expenditure is a combination of capital and operating expenditure.

High level scope of work

<u>Task 1 – Develop customer education and incentives program</u>

133. Given that suitable metering (see Section 2) has been rolled out throughout the JEN network the customer base from which participants can be drawn is large. JEN therefore proposes to extensively survey customers by consumer categories and tranches and then embark on a participant recruitment campaign of volunteers to participate in the trial.

134. Implementing this project will start with designing the customer education and enrolment campaign that focuses on strategies that promote customer education and awareness specifically targeted at different customer categories and demand tranches with the goal being to manage those customers' demand that most heavily contributes to peak loading on the network. Contemporaneously with this task, JEN will undertake a design review of possible innovative tariffs that incentivise consumers to manage demand, especially during peak periods and may include critical peak pricing **CPP**, time of use (**ToU**), dynamic and locational tariffs.

<u>Task 2 – Marketing and customer enrolment</u>

135. On completion of the above activities a marketing campaign will be undertaken with the goal being to recruit participants from the pool of identified consumers who will assist JEN in understanding the drivers of consumer behaviour patterns and how they respond to demand side management. On bedding down the participant base, customers will be educated on the need for managing peak demand because of its deleterious impact on network costs and the methods whereby peak demand can be managed.

<u>Task 3 – Technology enhancements</u>

136. Work with IHD suppliers in developing extra functionalities required for this trial:

- Inform customer when supply capacity control is required by raising an alarm or/and change in display colour
- Raise alarm when customer load limit is breached.

137. Other technology options for keeping customers informed on their energy and power usage will be investigated. These include providing customers a comprehensive home energy management analysis to understand their consumption patterns and attributes of connected appliances. Another option here is an enhancement of JEN's web portal to facilitate increased uptake and more interactive, user-friendly features.

Task 4 - Field trial

138. The field trial proper will then commence with IHDs distributed to a select number of participants and the roll out of a new tariff on a limited basis for these participants. The field trial proper will cover at least on one summer period. Data collected from the trial will be crucial to undertaking advanced data analytics that inform on the efficacy of the education campaign, use of technology such as IHDs and leveraging the capabilities of AMI.

Task 5 - Reporting and recommendations

139. This trial project is expected to run for an entire summer period, during which time monthly progress reports will be prepared and issued documenting

- Outcomes of the education program
- Observed changed behaviours in response to cost reflective tariffs
- Costs incurred
- Status to date.

140. This will provide the material for detailed a case study to be documented detailing all the matters to do with the implementation, delivery and lessons learnt from the trial.

Implementation costs

141. Implementation costs for this project are estimated to total $639,600 for the running of the trial over a period of 24 months from Q1, 2016 to Q4, 2017.

3.3.4 TECHNOLOGY AND ECONOMIC ASSESSMENT OF RESIDENTIAL ENERGY STORAGE

Objective

142. To evaluate the technical and economic viability of residential scale energy storage solutions when deployed in conjunction with rooftop solar PV systems.

Problem statement

143. An emerging trend, both globally and in Australia, is the rise of the ‘prosumer’[31] who aims to be more self-sufficient in electricity requirements. In the coming years, prosumers, either residential or commercial/industrial will have effective energy management systems that balance their generation[32] with their consumption. But as discussed in Section 2, renewable energy sources have a significant drawback in that they provide power intermittently and often when there is no, or little, demand for it. This has the added disadvantage of impacting on the quality of the electricity supply (for example, overvoltage, voltage flickers). If this power could be stored and released when there is a demand for it, then this handicap would be overcome. Distributed battery storage provides a solution.

144. The CSIRO[33] and others have predicted a high uptake of such technologies as one possible scenario for the next twenty years given the increasing trend in retail electricity prices and decreasing trend in costs of battery storage and solar PV panels. Distribution businesses need to develop their understanding on the technological

[31] A term coined to describe customers who are both producers and consumers of electricity.

[32] This is normally from renewable sources such as PVs and micro wind turbines.

[33] CSIRO and ROAM Consulting, Modelling the Future Grid Forum scenarios - December 2013

impact of increased uptake of such systems, both at the customer connection point and at an aggregate level (high voltage (**HV**) feeder or zone substation). Furthermore, the economic and price parameters that will drive customer strategies on charging and discharging will be an important input to tariff and pricing.

Project expectations and identifiable benefits

145. This project aims to test battery operation paired with PV in order to understand the capability of distributed generation and storage to support a customer's consumption patterns. The project also aims to study methods of optimising distributed storage in dealing with peak demand and determining the value to a DNSP of exercising control over battery operation (i.e. using techniques similar to ripple control for water heating). It is expected that this work will give rise to the development of models that scale up battery storage paired with PV units in order to extrapolate the aggregate impact of multiple units on the operation of the grid. Specifically this project proposes the following:

- Undertake field trials and supporting desktop technical analysis to identify constraints that limit the effective connection of residential distributed battery storage paired with PV and determine the optimal charge/discharge control strategy to manage peak demand
- Identify economic and financial parameters critical for the increased uptake of such technologies
- Investigate technological and operational solutions that facilitate such connections while minimising adverse impacts on the network and other customers
- Trial the potential solutions using a typical residential battery system paired with PV.

146. Benefits flowing from this trial relate to being informed of the rapid developments to the electricity landscape that could potentially see the stranding of DNSPs' assets through reduced energy throughputs and grid defection with the consequential increase in electricity prices for consumers. The trial will assist in formulating strategies and business models that DNSPs ought to pursue to ensure that businesses remain viable and consumers continue to be well served with an essential service. These trial outcomes are in line with the AER's DMEGCIS criteria.

Compliance with DMIA criteria

Section 3.1.3 of the AER's DMEGCIS for JEN states that programs and projects need to meet the DMIA criteria in order to be eligible for approval under the DMIS. This trial project complies with the DMIA criteria as follows:

- The project is aimed at developing technical solutions for the increased uptake of residential scale energy storage solutions when deployed in conjunction with rooftop solar PV systems and thereby reducing demand for standard control services, rather than increasing supply capacity through network augmentation.
- The project is a broad based demand management initiative which aims to reduce demand for standard control services across the JEN network. This project is targeted towards customers will be owners of residential scale energy storage devices.
- The project deliverables are to investigate technical barriers and formulate solutions for the increased uptake of residential energy storage as an efficient demand management solution.
- The project is a non-tariff based project.
- The project cost will not be recovered under any other jurisdictional incentive scheme or State or Commonwealth Government scheme, and have not been included in forecast capital or operating expenditure proposal for the 2016 regulatory period.
- The nature of expenditure is a combination of capital and operating expenditure.

High level scope of work

Task 1 – Customer recruitment

147. A survey of residential sites with PV installations and analysis of their demand profiles will be undertaken with the view of introducing distributed battery storage on the site. Having identified a population size of suitable sites, owners will then be invited to volunteer to participate in the trial. The number of volunteers that can participate in this trial will be primarily constrained by the capital cost of the storage systems.

148. Defining the trial program and sourcing target participants determined by their load profiles will kick off this project. Thereafter volunteers will be recruited and contracted to participate in the trial.

Task 2 – Procurement and technology deployment

149. At the same time as the recruitment process is taking place, technical and commercial processes will be designed and documented and a list of devices, appliances and materials needed for the trial will be drawn up. Deployment of technology is foreseen to provide for the:

- Installation of a small residential scale battery system (i.e. 5kW, 10kWh Lithium-Ion or similar) at each selected site, which includes a fully functional battery management and power conversion system.
- Installation of appropriate measuring devices to monitor and record variations in system current, voltage, harmonics, etc.

Task 3 – Field trial

150. Thereafter the field testing and monitoring phase of the trial will get underway with the:

- Performance testing of the unit with the PV system in service only (and without battery storage system), test and record the results and assess the performance of the system for a period of one month. Measuring and recording system events and faults will form the baseline system operation without battery storage.
- Programming of the battery management system so as to test various charge/discharge scenarios in response to net load, price signals or system conditions (i.e. voltage and current).
- Undertaking integrated testing of the PV generator and battery storage system to identify technical constraints both on the customer side and network side of the grid.
- Measuring and recording of normal operations and impact on the network due to system events and faults for a period of three months with battery storage and PV systems in service.

Task 4 – Desktop analysis

151. Following the field trial, desktop technical and economic analysis will see the:

- Development of a simulation model of PV generation on JEN’s LV network and the integration with the appropriate engineering software model platform(s).
- Development of technology and operational solutions to efficiently connect residential PV paired with battery storage with the solutions aiming for favourable economic outcomes for both the network and customers.
- The economic and financial assessment identifying the parameters critical for increased uptake of this technology in the residential sector and the development of customer strategies that maximise throughput and minimise reliance on grid supply.

Task 5 – Reporting and recommendations

152. Conduct of the trial is foreseen to be over a period of 24 months and incorporate summer and winter periods when there is seasonal variation of available sunlight hours and customer consumption. During the trial, quarterly progress reports will be prepared and issued documenting:

- Key equipment installed
- Testing performed
- Analysis undertaken
- Costs incurred
- Status to date.

153. This will provide the material for detailed analysis of battery storage systems paired with PV and the system simulation of aggregated volunteers to be performed. This work will then lead to scenario modelling that will be incorporated into a case study documenting the impact on individual customers and on the grid.

Implementation costs

154. This project is estimated to cost $610,600 for the running of the trial over a period of 24 months from Q1, 2019 to Q4, 2020.

155. JEN has undertaken consultations with suppliers of residential battery storage solutions and has received preliminary estimates of the cost of such solutions. The trial costs have been based on these estimates.

3.3.5 DISTRIBUTED GRID ENERGY STORAGE

Objective

156. To trial distributed energy storage solutions as a means of providing increased capacity to the network during times of peak demand and maintaining quality of electricity supply.

Problem statement

157. As discussed in Section 2.7 JEN's traditional peak demand growth of about 2.75% per annum has been met with fixed assets comprising HV and LV lines and transformers. As the capacity of these assets was taken up by the growth in demand, new assets were planned and constructed. But in recent years altered consumer behaviour coupled with new technologies has challenged this conventional planning model. Demand growth has reduced and in some areas of the network is expected to regress in the coming years. Also, consumers are increasingly contemplating new ways of managing their demand that include energy efficiency mechanisms (i.e. low energy consumption appliances, etc.) or installation of on-site embedded generation.

158. These trends make it increasingly difficult for DNSPs, including JEN, to develop network augmentation plans and make investment decisions on long life fixed assets. There is a clear need to identify and implement solutions to capacity constraints that are flexible, scalable and offer the best value to customers.

Project expectations and identifiable benefits

159. This project aims to engage in both a desktop technical analysis and a field trial that:

- Undertakes system studies to determine the efficacy of grid storage as an alternative to traditional network augmentation

- Identifies a suitable location within JEN's network to deploy and trial grid storage and carry out tests of individual grid storage systems to determine critical parameters needed for peak demand reduction, efficiency, charge/discharge duty cycles and other pertinent parameters
- Integrates systems testing for the fleet of grid storage systems to determine critical parameters particularly in relation to communications and control
- Determines the suitability of grid storage in mitigating power quality degradation caused by high penetration of roof top PVs.

160. Grid storage is a demand management technique, which can be strategically deployed across the network to not only provide for the extra capacity required during times of peak demand but also to afford a flexible alternative to long term fixed asset investments. Equally important is that grid storage can be specifically targeted at local areas of constraint or to mitigate issues of power quality caused by the high penetration of PVs and when suitably designed, can be relocated to other sites when demand growth is no longer an issue at the local area where it is connected. It is expected that the trial will inform on the efficacy of using grid storage as a means of providing increased network capacity during times of peak demand and mitigate local area power quality concerns. These trial outcomes are in line with the AER's DMEGCIS criteria.

Compliance with DMIA criteria

Section 3.1.3 of the AER's DMEGCIS for JEN states that programs and projects need to meet the DMIA criteria in order to be eligible for approval under the DMIS. This trial project complies with the DMIA criteria as follows:

- The project is aimed at developing distributed energy storage solutions as a means of providing increased capacity to the network during times of peak demand and thereby reducing demand for standard control services, rather than increasing supply capacity through network augmentation.
- The project is a peak demand management initiative which aims to address specific network constraints by reducing demand on the network at the location and time of the constraint.
- The project deliverables are to investigate grid sized energy storage as an efficient demand management solution.
- The project is a non-tariff based project.
- The project cost will not be recovered under any other jurisdictional incentive scheme or State or Commonwealth Government scheme, and have not been included in forecast capital or operating expenditure proposal for the 2016 regulatory period.
- The nature of expenditure is a combination of capital and operating expenditure.

High level scope of work

<u>Task 1 – Site and technology selection</u>

161. Analysis of the candidate energy storage technologies will be undertaken to determine the parameters that are critical to particular applications, such as reduction of peak demand that will allow the specifics of the grid storage systems to be selected. Due to budgetary considerations, the size of the trial may be limited to four to five storage installations with power ratings 25 kW to 50 KW per installation. This analysis will then further inform on the selection of an appropriate trial site. It is expected that a likely candidate site would be a HV feeder which is or is nearing capacity constraint and experiencing low to moderate load growth in a 10 year planning horizon.

Task 2 – Desktop analysis

162. Technical and systems studies will be undertaken to evaluate the efficacy of grid storage for mitigating capacity constraints as a feasible alternative to the deployment of long life assets. This will be a site specific assessment. An economic assessment of the costs and benefits of various network scenarios that take account of load growth, generation profiles and other variables so that their sensitivity for the proposed solution can be gauged will be performed.

Task 3 – Field trial

163. Having completed the up front desktop studies, the activities associated with procuring and installing the grid storage systems at appropriate locations will commence. Following the deployment of the grid storage systems, appropriate measuring devices to monitor and record system current, voltage, harmonics, etc., will be installed. With the monitors installed, unit testing of individual grid storage systems will be undertaken to measure and record the impact of system events and faults for a period of approximately three to six months.

164. During this period, integrated systems testing for all the deployed grid storage systems, with a particular focus on communications and control, will also be undertaken. Investigation and testing of the grid storage system's Power Conversion System (**PCS**) to mitigate power quality issues caused by intermittent embedded generation will also take place. Of particular interest will be the ability of grid storage to manage voltage step and flicker at the HV and LV levels.

Task 4 – Recommendations and reporting

165. Cross checking of results of the field trials with simulation results derived from the desktop studies will round off the trial. The learnings from a limited trial would then be extrapolated for a more widespread deployment of similar sized or larger energy storage systems.

166. This will provide the material for a detailed case study documenting all of the processes, procedures, activation, trial analyses and simulations performed during the trial and the business case needed for grid storage to qualify as a credible and viable non-network alternative. A suite of recommendations will be developed for operationalizing the solution.

167. During the trial, quarterly progress reports will be prepared and issued documenting:

- Key equipment procured
- Key equipment installed
- Field activation and trialling performed
- Results of the desktop studies
- Costs incurred
- Status to date.

Implementation costs

168. This grid storage project is estimated to total $1,847,600 for the running of the trial over a period of 30 months from Q3, 2016 to Q4, 2018.

169. JEN has consulted with suppliers of energy storage solutions for distribution networks on the scope and costs of such a trial project and has received preliminary quotations on turnkey solutions, which form the basis of the trial costs.

3.3.6 DEMAND RESPONSE FIELD TRIAL – PHASE 2

Objective

170. To field trial demand response achieved by aggregating large commercial and industrial load, as a means for reducing network demand during peak load or outage conditions.

Problem statement

171. As described in Section 2, demand response (**DR**) is a particular type of demand management initiative involving contracted load reduction either controlled by customers or by the network through direct load control. In the current environment, foundations for an effective and vibrant demand response marketplace are beginning to emerge. Demand response aggregators and some large customers are beginning to implement demand response solutions to keep electricity costs low, especially where these customers are on a maximum demand tariff. It can be reasonably predicted that such solutions will start to become viable on a larger scale and can be implemented to mitigate capacity constraints on distribution networks. JEN also expects demand response aggregators to submit technically acceptable and price competitive proposals in response to our upcoming RIT-D projects. Hence, there is a need for us to better understand the operational issues with large scale demand response projects so that we can further develop internal processes and procedures that facilitate an uptake in this area.

Project expectations and identifiable benefits

172. JEN is expected to complete in early 2015 Phase 1 of a Demand Response Field Trial (**DRFT**) project to undertake desktop analysis and develop models that capture the benefits, costs and operational structures of targeted demand response programs. Phase 2 of this project is proposed to field trial the technology, customer acquisition and contracting processes and operational dispatch methodologies in a constrained area of the network. The goal is to achieve the targeted demand response primarily by aggregating large commercial and industrial loads.

173. The learnings from this trial will facilitate change and innovation as JEN continues to;

- Build demand management expertise within our organisation to ensure demand management methodologies that can be introduced meet customer and stakeholder expectation
- Reinforce the lessons derived from the demand response trials with targeted projects and information campaigns
- Engage with third party demand aggregators (through our annual planning review process) about specific opportunities for non-network solutions to alleviate emerging network constraints.

174. The field trial will assist JEN in developing targeted solutions for solving capacity constraints and set up internal processes to make demand response a viable solution for the JEN network in the near future. These trial outcomes are in line with the AER's DMEGCIS criteria.

Compliance with DMIA criteria

Section 3.1.3 of the AER's DMEGCIS for JEN states that programs and projects need to meet the DMIA criteria in order to be eligible for approval under the DMIS. This trial project complies with the DMIA criteria as follows:

- The project is aimed at developing JEN's capabilities to reduce peak demand through customer controlled demand response projects, rather than increasing supply capacity through network augmentation.
- The project is a peak demand management initiative which aims to address specific network constraints by reducing demand on the network at the location and time of the constraint.

- The project deliverables are to prepare JEN for various elements of customer controlled demand response programs as an effective and efficient demand management solution.
- The project is a non-tariff based project.
- The project cost will not be recovered under any other jurisdictional incentive scheme or State or Commonwealth Government scheme, and have not been included in forecast capital or operating expenditure proposal for the 2016 regulatory period.
- The nature of expenditure is a combination of capital and operating expenditure.

High level scope of work

Task 1 – Customer survey, enrolment and contracting

175. A desktop and field survey of potential participants will be undertaken and activities related to customer enrolment will be commenced. The customers from a pre-determined constrained area will be enrolled for the trial so that response times, DR firmness, reliability of dispatch, dispatch techniques and network DR benefits can be assessed.

176. It is expected that there will a total eight to ten DR sites out of which three to four sites will have "fast response" capability and a further five to six sites will be enabled with "automated messaging".

Task 2 – Technology deployment and testing

177. Demand response enabling hardware and associated communications equipment will be installed at the customer site. Hardware integrity tests and load drop tests will be performed and will form the basis for enrolment and dispatch fees payable to the customer by JEN.

Task 3 – Field trial

178. The trial will be conducted from 2016 and 2017 to encompass summer peak events, winter peak events and the Victorian storm season. JEN will contract directly with customers and supply the required hardware to each customer for the duration of the program.

179. JEN will pay customers a combination of enrolment and dispatch fees to incentivise participation. JEN will pay customers from a baseline established during a load drop test undertaken per Task 2 above.

180. This project will be used to facilitate DR as a potential solution for network capacity constraints by validating assumptions on customer acquisition and contracting; dispatch mechanisms; operational performance and network impact.

Task 4 – Recommendations and reporting

181. Cross checking of results of the field trials with the Phase 1 desktop studies will round off the trial. The learnings from a limited trial would then be extrapolated for a more widespread deployment of similar sized or larger demand response programs.

182. This will provide the material for a detailed case study documenting all of the processes, procedures, activation, trialling analyses and customer experience during the trial. A suite of recommendations will be developed for operationalising the solution.

183. During the trial, quarterly progress reports will be prepared and issued documenting:

- Key equipment procured

- Key equipment installed
- Field activation and trialling performed
- Results of the desktop studies
- Costs incurred
- Status to date.

Implementation costs

184. This demand response trial project Phase 2 is estimated to total $660,000 for the running of the trial over a period of 24 months from Q1, 2016 to Q4, 2017.

185. The project estimates are derived from desktop models developed as part of the DR field trial – Phase 1. The model considers a number of parameters including number of project establishment (customer enrolment etc.) costs, DR hardware costs (standard vs. fast response), customer payment profiles (capacity payments, performance payments) and operating/dispatch expenses.

3.4 CONSOLIDATED PROGRAM COSTS

186. Table 3–1 depicts the consolidated total projected cost of the proposed DMIS trial program. It includes a cost breakdown for each trial and the year in which the expense is expected to be incurred.

Table 3–1: Total projected cost of DMIS trial program ($2015, $ thousand)

Trial No.	Trial Name	2016	2017	2018	2019	2020	Total Cost (2016 – 2020)
1	Efficient connection of micro embedded generators			153	306	306	**765**
2	Direct load control trial		207	414	414		**1,035**
3	Managing peak demand through customer engagement	320	320				**640**
4	Technology and economic assessment of residential energy storage				244	366	**610**
5	Distributed grid energy storage	369	739	739			**1,847**
6	Demand response field trial	396	264				**660**
	Total	**1,085**	**1,530**	**1,306**	**964**	**672**	**5,557**

187. The DMIA will be provided as an annual, ex-ante allowance in the form of a fixed amount of additional revenue at the commencement of each regulatory year of the regulatory control period. The total amount of the allowance will be distributed evenly across each regulatory year of the regulatory control period.[34]

188. JEN proposes that the total amount recoverable over the 2016 regulatory period under the DMIA as $5,557,000. Within the regulatory control period JEN proposes to have the flexibility to select an expenditure profile that suits its needs, as projected in table above.

[34] AER, *Demand Management and Embedded Generation Incentive Scheme, Jemena, CitiPower, PowerCor, AusNet Services and United Energy, 2016-20*, 21 November 2014, Section 3.1.2 – Access to the DMIA

Attachment A Trial schedules

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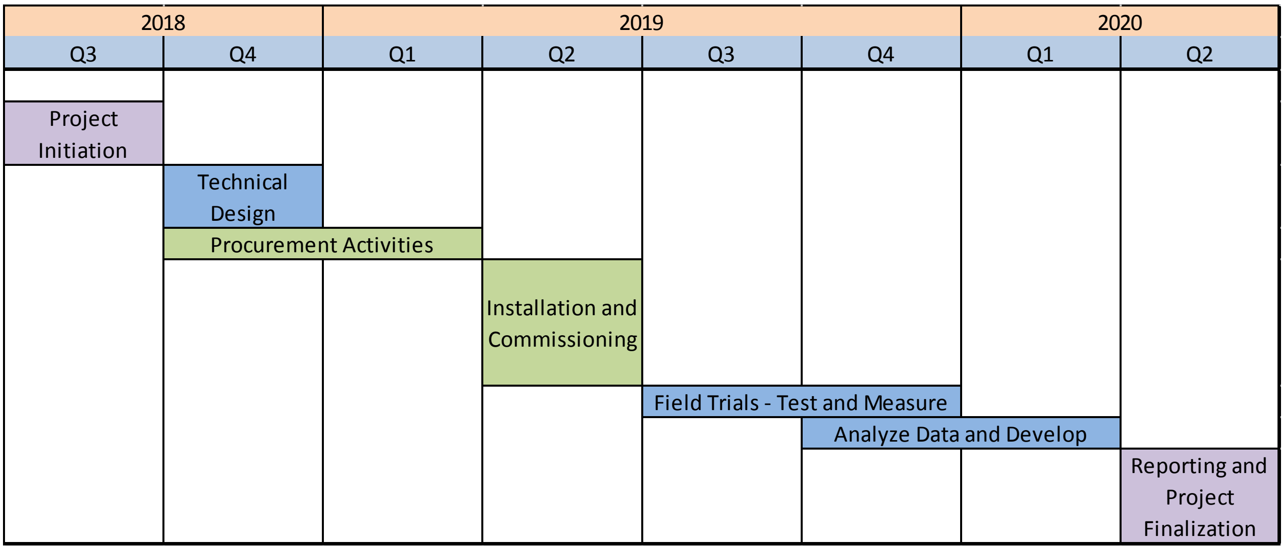
A1. EFFICIENT CONNECTION OF MICRO EMBEDDED GENERATORS

Trial Schedule No. 1	Connection of micro embedded generators
Purpose	
The purpose of the trial is to analyse the technical constraints that limit the ability of LV networks to host micro-embedded generators such as rooftop solar PV.	
Location	
The location of the field trial is TBA. Solutions developed will also be trialled at select customer sites.	
Customer details	
Customers with existing solar PV installations will be selected and participation in the trial will be on a voluntary basis.	
Equipment fitted	

Equipment	Details
JEN assets	
Solar PV panels	Maximum 100 kW of generating capacity.
Technology solutions – primary plant	LV regulators, on-load tap changing distribution transformers, capacitor banks etc.
Field testing, measuring and recording equipment	PQ meters etc.
Other secondary plant equipment	Includes relays, protection panels and fit-out.
Customer Assets	
N/A	

SCADA/communications	
No additional data communication infrastructure is required.	
Timeline	



Total expenditure estimate

Item	2015 $
Generating equipment, primary plant and site works	$340,000
Testing, measurement and secondary plant	$70,000
Planning and design	$66,800
Project management, construction management and customer relationship management	$133,500
Technical analysis and studies	$116,250
Regulatory requirements and reporting	$38,250
Total	**$764,800**

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A2. DIRECT LOAD CONTROL TRIAL

Trial Schedule No. 2	Demand shifting through engagement and AMI

Purpose

The purpose of the project is to test the effect of DLC and develop DLC dispatch algorithms that optimise load reduction amongst participating customers in the trial.

Location

The location of the field trial is to be selected once the trial has been sanctioned.

It is expected that an appropriate supply area within the JEN service area will be chosen to ensure that benefits of DLC can be quantified and related back to specific network constraints. A limited marketing campaign will be undertaken to recruit residential customers within the chosen supply area.

Customer details

Customers selected for the trial will need to have smart meters deployed at their sites.

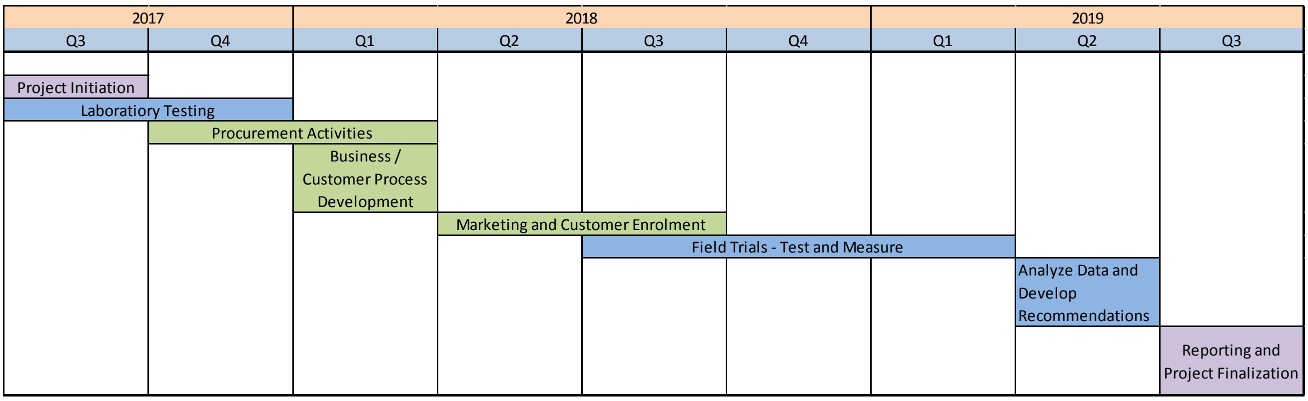
Equipment fitted

Equipment	Details
JEN Assets	
N/A	
Customer Assets	
Demand Response Enabling Devices (**DRED**) and smart appliances	DRED or smart meter enabled appliances deployed in residential households

SCADA /communications

No additional data communication infrastructure is required.

Timeline



Total expenditure estimate

Item	2015 $
DRED and Smart Appliances – supply and install	$570,000
Project management	$92,400
Customer management and commercials	$72,000
Project technical and analysis	$196,000
Field rollout and testing	$52,000
Regulatory and reporting	$52,000
Total	**$1,034,400**

A3. MANAGING PEAK DEMAND THROUGH CUSTOMER ENGAGEMENT

Trial Schedule No. 3	Managing Peak Demand through Customer Engagement

Background

The trial is aims to quantify and identify educational materials, tools, methods, techniques and pricing that assist in incentivising customers in managing their peak demand.

Location

The entire JEN network.

Customer details

Customer Category	No.
Small Commercial	40 – 50
Residential	400 – 450

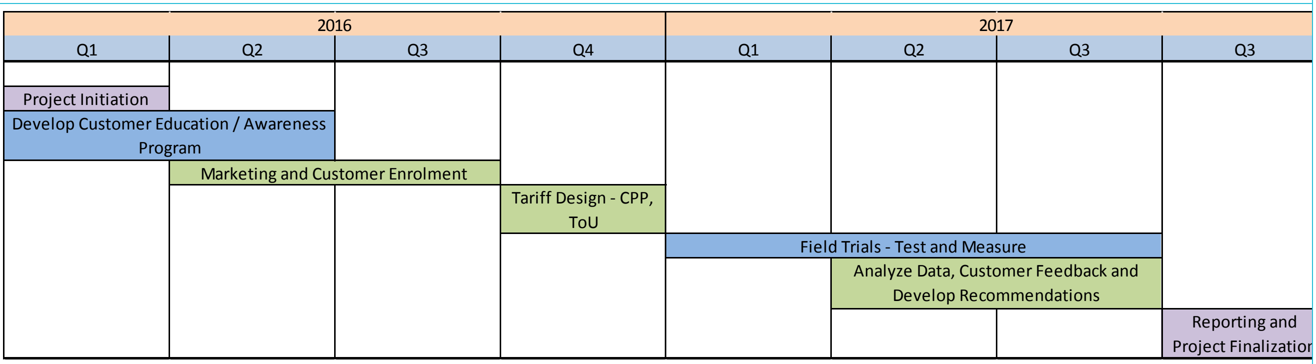
Equipment fitted

Equipment	Details
JEN Assets	
N/A	
Customer Assets	
In home display (IHD)	ZigBee HAN

SCADA/communications

No additional data communication infrastructure is required.

Timeline



Total expenditure estimate

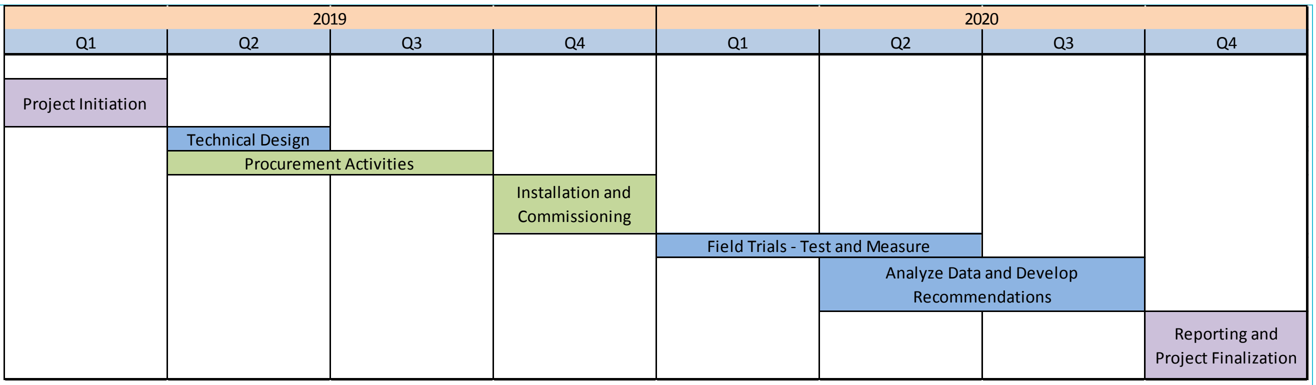
Item	2015 $
In-Home Display (IHD) units– supply and install	$115,000
Project management	$87,400
Customer education, marketing and enrolment	$133,250
Customer management and commercials	$38,700
Project technical, rollout and communications interface	$82,750
Customer behaviour analysis and data analytics	$143,000
Regulatory and reporting	$39,500
Total	**$639,600**

A4. TECHNOLOGY AND ECONOMIC ASSESSMENT OF RESIDENTIAL ENRGY STORAGE

Trial Schedule No. 4	Residential energy storage
Background	
The purpose of this trial is to evaluate the technical and economic viability of residential battery storage paired with PV systems. The trial outcomes will assist in identifying key barriers for wide scale uptake of such systems and determine the technical issues of concern both for customers and DNSPs.	
Location	
The location of the field trial is to be determined after scoping studies have been complete. It is expected that 2-3 customer sites within the JEN network will be chosen to ensure that the field results are representative of the network. The sites will need to meet the applicable regulations for a trial of this nature and provide unrestricted access to JEN engineers and service delivery staff.	
Customer details	
Customers with existing solar PV installations will be selected and participation in the trial will be on a voluntary basis.	
Equipment fitted	

Equipment	Details
JEN Assets	
Solar PV panels	Maximum 10kW of generating capacity
Battery systems	5kW, 10kWh Battery Systems + PCS
Technology solutions - primary plant	LV regulators, on-load tap changing distribution transformers, capacitor banks, etc.
Field testing, measuring and recording equipment	PQ meters, etc.
Other secondary plant equipment	Includes relays, protection panels and fit-out
Customer Assets	
N/A	

SCADA/Communications	
No additional data communication infrastructure is required.	
Timeline	



Total expenditure estimate

Item	2015 $
Generating equipment and other primary plant	$75,000
5kW, 10kWh battery systems + PCS	$85,000
Testing, measuring and secondary plant	$30,000
Project and Construction Management	$141,800
Project - Design and Technical Analysis	$129,300
Project - Economic Analysis and Pricing	$102,500
Regulatory and Reporting	$47,000
Total	**$610,600**

A5. DISTRIBUTED GRID ENERGY STORAGE

Trial Schedule No. 5	Grid storage

Background

The purpose of this project is to trial grid storage as a means of providing increased capacity to the network during times of peak demand and to mitigate local area power quality issues arising as a consequence of increased penetration of roof top PV installations.

Location

The location of the field trial is to be determined after the technical desk top studies and system simulation analyses have indicated potentially suitable sites. It is expected that likely candidate sites will be a HV feeder, which is capacity constrained and experiencing low to moderate load growth in the 10 year planning horizon.

Customer details

N/A

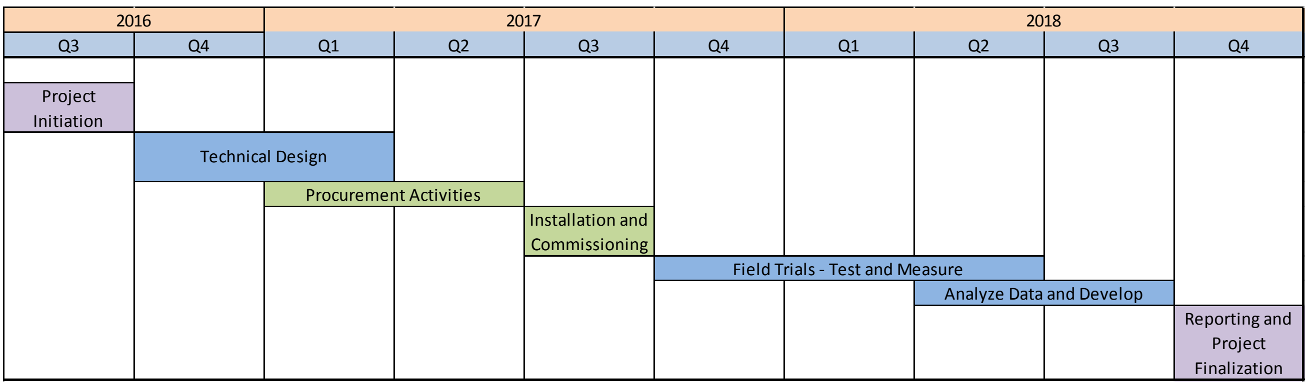
Equipment fitted

Equipment	Details
JEN Assets	
Distributed energy storage systems	25 kW, 50 kWh below ground Li-Ion Batteries
Management software	Distribution and storage management software
Field testing, measuring and recording equipment	PQ meters etc.
Other secondary plant equipment	Includes relays, protection panels and fit-out
Customer Assets	
N/A	

SCADA/communications

No additional data communication infrastructure is required.

Timeline



Total expenditure estimate

Item	2015 $
25kW, 50kWh buried Li-Ion batteries	$1,300,000
Communications equipment	$35,000
Distribution and storage management software	$120,000
Project management	$103,650
Project planning	$27,500
Technical support	$220,700
Reporting	$40,750
Total	**$1,847,600**

A6. DEMAND RESPONSE FIELD TRIAL – PHASE 2

Trial Schedule No. 6	Demand Response Field Trial

Background

The purpose of this project is to trial customer initiated demand response for managing peak demand. Phase 1 of this project is currently underway in 2014-15. It will provide desktop analysis and models to further JEN's understanding of the benefits, costs and operational consideration for demand response. Phase 2 of the trial proposed in 2016 and 2017 will field test the models developed and provide for learnings in a practical sense.

Location

The location of the field trial is to be determined. A constrained region within the JEN network will be selected to understand the tangible benefits of demand response as a means of reducing peak demand.

Customer details

These customers are expected to be mid to large commercial / industrial customers connecting to the LV or HV networks.

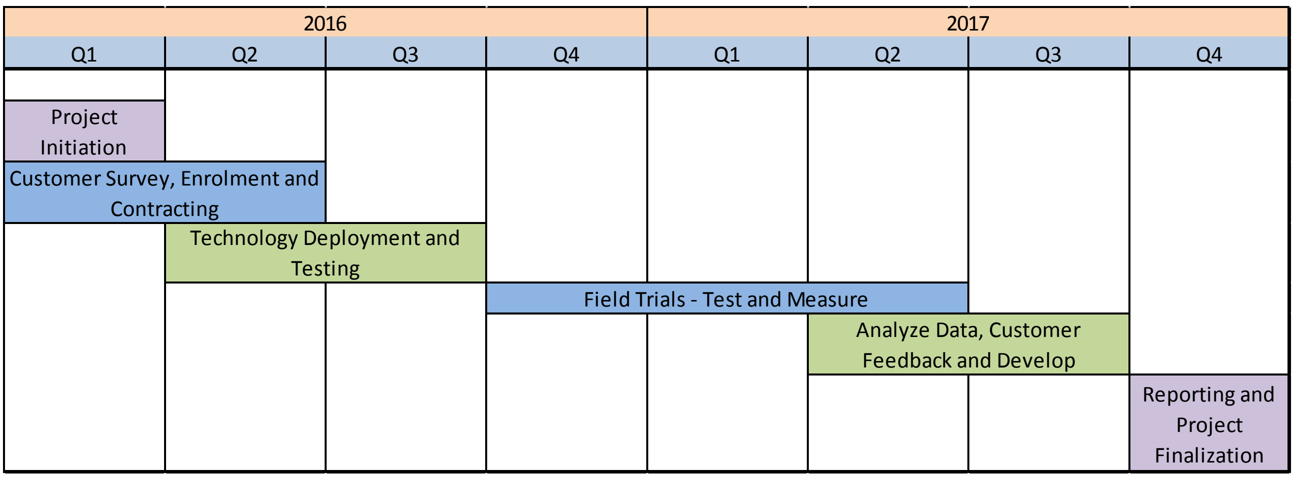
Equipment fitted

Equipment	Details
JEN Assets	
Demand response enabling hardware	The hardware units installed at customer sites should be capable of responding to remote signals from JEN or a nominated third party
Management software	Control, coordination and dispatch of demand response
Customer Assets	
On site cabling and communications	

SCADA/communications

The demand response enabling hardware will need to be fitted with 3G modems to communicate with JEN IT servers or those of a JEN nominated third party provider.

Timeline



Total expenditure estimate

Item	2015 $
Demand response enabling hardware and supporting systems	$250,000
Project management, management and software	$100,000
Customer hardware and Incentive payments	$150,000
Marketing and customer acquisition	$40,000
Technical support	$80,000
Reporting	$40,000
Total	**$660,000**