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Electricity Distribution Network

Network Support Services

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Disclaimer

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1 Executive Summary

1.1 Purpose

Acknowledging AusNet Services' vision to ***"provide our customers with superior network and energy solutions"*** this asset management strategy guides the commercial application of demand management and non-network solutions, known as Network Support Services, to manage constraints within the electricity distribution network within the context of strengthened regulatory obligations and dedicated revenues established in the 2016-2020 Electricity Distribution Price Review.

This strategy informs the distribution network planning and design functions of the drivers for uptake of Network Support Services available in the market, and proposes a framework to guide the decision making process around selection of suitable network support options.

1.2 Background

Network Support Services refer to the suite of non-network solutions and Demand Management (DM) techniques available for procurement by AusNet Services to manage the level of energy at risk on the network. Such services can include embedded generation, embedded storage and customer demand response.

Over an extended period, AusNet Services has managed capacity constraints in the electricity distribution network by contracting permanent generators such as at Bairnsdale, deploying a fleet of containerised, mobile generators in Euroa, and hiring smaller generators for Nagambie and Phillip Island. In 2012 AusNet Services established a five-year Network Support Agreement to defer augmentation at Traralgon zone substation with an embedded generation service provider. AusNet Services has also employed temporary installations using smaller capacity diesel fuelled generators to mitigate the impact of planned network outages on customers.

In recent years, AusNet Services has procured the fleet of mobile diesel generators, has engaged large customers to provide demand response under network support agreements and has completed trials into the use of battery storage to provide network support at both grid-scale and behind the meter.

Increasing requirements for more economic and efficient solutions to manage short term constraints have emphasised the importance of non-network solutions and demand management to provide Network Support Services.

With the recent slowing in demand growth coupled with increases in evening peak demand, it is common for network circuits to experience a relatively small quantity of load at risk (typically 1-5MW), that is growing at a slow but unpredictable rate. This type of situation makes long term investments such as network augmentation more risky. Network Support Services can however offer a flexible short to medium term solution until demand growth trends become firm.

The Australian Energy Regulator (AER), in its 2016-2020 determination on non-network operational expenditure (OPEX) and capital expenditure (CAPEX), granted funding for non-network demand management solutions, capability development and resources required in anticipation of increased regulatory requirements. AusNet Services also received [C.I.C] funding from the Demand Management Innovation Allowance. This innovation funding was intended to address perceived failures by Distribution Network Service Providers (DNSPs) to assess non-network alternatives in the mitigation of network constraints.

In October 2012 the Australian Energy Market Commission (AEMC) made a final rule establishing the Distribution Network Planning and Expansion Framework in response to a proposal by the Ministerial Council on Energy (MCE)[1]. The Framework comprises three interrelated components: a *Distribution Annual Planning Report (DAPR)*; a *Demand Side Engagement Strategy*; and a *Regulatory Investment Test for Distribution (RIT-D)* process.

This document describes AusNet Services' approach to Network Support Services in its network planning and decision-making processes to ensure the most efficient and effective solutions are chosen to address network constraints.

1.3 Types of Network Support Services

Successful use of Network Support Services relies on matching the network performance requirement with the technical performance capabilities and economics of the different types of services. These services cover demand-side response and installation of non-network solutions, and comprise:

- **Commercial & Industrial Customer Demand Management**, where it can be contracted, offers a significantly lower cost than most other network support options where only a short number of hours of response are required. Commercial & Industrial Customer Demand Management (C&I DM) typically has limitations on the reliability of response, known as firmness, and the number of hours of network support provision. Trials were performed over the last few years to test the reliability, performance and cost of C&I DM in practice. C&I DM is currently most suited to load reductions in the order of 200 kW up to 1 MW. Thus far C&I DM has proved to be a finite resource that is specific to a particular network area and limited by customers' willingness and capability to shift load or switch over to on-site, behind-the-meter generation, and may only be sufficient to mitigate rather than eliminate a particular constraint.

- **Embedded Generation** (EG) has been technically and economically successful in managing network capacity constraints and reliability risk in the electricity distribution network in a variety of situations over an extended period. EG has a higher fixed cost than C&I DM, but has a higher level of firmness and can provide a longer duration of network support. EG is often provided by either temporary units of around 1 MW or contracting service from permanent installations of around 5 MW or more.

- **Battery storage** currently has a high capital cost but is on a declining cost curve and is starting to find applications to provide network support, particularly in areas where voltage support and increasing renewable generation hosting capacity is required. Battery storage can range from residential customer installations of around 3kW up to grid-scale application 1MW or more.

- **Residential Customer Demand Management** (or Demand Response) captures a suite of techniques that typically address at-source one of the main causes of peak demand; residential heating & cooling. Randomised time-clocks for dedicated overnight loads such as hot water systems and some heating systems is a proven and highly cost effective method of managing the short term network demand spikes that can occur from simultaneous switching of these loads during an otherwise off-peak time. The current integration of smart metering and smart grid technologies into AusNet Services' operations have helped facilitate the active provision of network support by residential consumers or aggregators of end consumers. The recent "Good Grid" trial enlisted 980 customers across 3 postcodes with known summer constraints and utilised smart meter data to help determine the overall network benefit provided by the participating customers.

[1] AEMC – Completed Rule Change: Distribution Network planning and Expansion Framework, Reference ERC0131

1.4 Key Observations

A series of observations were made regarding the practical application of Network Support Services. These observations are summarised below:

- Subject to available fuel and planning permissions, natural gas fuelled generators of up to 10 MW capacity can be made operational in six months and diesel fuelled generators of up to 5 MW capacity can be made operational within six weeks. Network support agreements with Commercial and Industrial customers can take from 1 month up to 12 months to identify and negotiate, depending on size, industry and level of customer automation required.

- The 2016-20 EDPR provided incentives for further use and trial of non-network techniques and demand side options to mitigate network constraints; together with innovation funding of [C.I.C] for larger trials.

- Regulatory scrutiny is increasing on the transparent demonstration of constraint mitigation using the most economic non-network technique or network augmentation available. A key mechanism is the Regulatory Investment Test for Distribution (RIT-D) as described in section 3.2.4.

- Ownership and operation of grid connected embedded generation is subject to licensing, registration or exemption, and there are currently regulatory barriers for DNSPs to fully exploit these technologies.

- Related party regulations allow a DNSP to recover, through regulated charges, those network support costs where it can be demonstrated the services were acquired through a robust competitive process, or at an efficient market price.

- Long term network support agreements need sufficient contract flexibility to address changing load forecasts and regulated financial incentives such as S-Factor.

- The long-term network support agreement with Bairnsdale Power Station for the East Gippsland network has been in place, with the current agreement expiring in March 2020. A Regulatory Investment Test will be run to determine the most economically-efficient approach to manage the network of East Gippsland.

- Further development of the prevailing NPV financial model used in capital project business cases is underway, for evaluation of non-network options to the resolution of network constraints.

- Transition of these approaches and technologies into ongoing business will require enhanced training and flexibility from engineers and planners together with a wider skill set from service delivery teams.

- The Networks Renewed trial showed that network support for voltage compliance can be accomplished by leveraging reactive power capabilities of behind the meter solar and battery inverters.

- The Mooroolbark Community Minigrid trial demonstrated multiple mechanisms of network support by utilising behind the meter solar and storage as well as front of meter energy storage. By using the DENOP and communication pathways to the end devices, the trial was able support the network by acting as a VPP, peak lopping at the HV feeder level, islanding houses or a collection of houses off the network.

2 Implementation of Network Support Services

2.1 Current operating context

Across the years 2016 to 2018, AusNet Services has spent approximately [C.I.C] annually on reinforcing its distribution network to meet demand growth. Although this rate of investment is expected to slow in future years according to reduced demand growth forecasts, there remains a significant pipeline of capacity-driven projects where network support may be applicable. Augmentation works earmarked for investigation or development in the 2019-2023 Distribution Annual Planning Report (DAPR) included:

- two upgrade projects on 66kV sub-transmission lines
- two upgrade projects at zone substations (excluding REFCL-initiated works)
- three upgrade projects on 22kV feeders from existing stations

Augmentation works are typically driven by evening peak summer demand when solar PV generation falls away, air conditioning is still being used extensively and the capacity of the network is at its lowest due to higher ambient temperatures. Given that these demand peaks occur only occasionally throughout the year, a significant proportion of any augmentation capacity will have a low utilisation, and network support options can provide a more economical solution.

Where growth in network demand is slow, network support options may be able to defer network augmentation for several years by reducing demand peaks and keeping demand within asset ratings. Network support services may also provide an economic solution to reduce the Energy at Risk (EaR) associated with network constraints even when a network augmentation is not viable.

The growth in overall peak demand on the network has, in recent times, reduced from 12% (2015) to 3% (2019)[2] as a consequence of improved energy efficiency in buildings and appliances, and increased uptake of solar photovoltaic (PV) generation systems. However even at the current slower growth rate, localised peak-demand is still increasing in some areas and driving network expenditure as outlined in the DAPR.

At the same time, energy consumption is falling by around 2% p.a.[3] resulting in an increasingly peaky demand profile. Currently it is common for peak demand to be around 130% of average demand, but this could increase to over 150% over five years if current trends continue.

Network support solutions such as embedded generation or demand management contracts are deployed to reduce the peakiness of the network demand profile, thereby reducing the level of EaR on the network and deferring or avoiding the need to build new network capacity. In a similar fashion, network support can reduce the level of EaR associated with the likelihood of assets failing based on their condition. This may also allow replacement investment to be deferred.

[2] Values provided by Forecasting Team in August 2019.

[3] Values provided by Forecasting Team in August 2019..

2.2 Applications for Network Support Services

Network support services are usually applied in one of three main situations to help reduce the risk of customer supply interruption or avoid overloading network assets:

1. **Planned support to avoid forecast overload of feeder thermal ratings:** Due to forecast high summer ambient temperature conditions, some feeders are forecast to operate beyond their thermal ratings for relatively short periods of time (e.g. 4 hours overload on 4 hot summer days). Network support is deployed proactively to address this risk as part of the network Summer Preparedness process[4] that identifies priority feeders.
2. **Planned support to avoid forecast overload of zone substation N-1 ratings:** In the unlikely event of the loss of one transformer at a multi-transformer zone substation, the remaining transformers may be forecast to operate above their summer cyclic ratings, potentially for extended periods of time (e.g. 8+ hour periods on multiple consecutive days). Network support is deployed proactively to address this risk based on a longer-term business case.
3. **Unplanned emergency response to network contingency events:** Equipment failures may result in customers losing supply, or network assets being overloaded. Network support is deployed reactively to help manage these risks.

Regarding the first two planning-based situations, the application of Network Support Services is based on the forecast asset loadings and the EaR outputs from AusNet Services' probabilistic planning methodology that relies on relatively sophisticated demand forecasts for each 66kV and 22kV major network circuit.

In these situations Network Support Services can avoid asset overload, reduce EaR, defer planned augmentation, or potentially avoid augmentation if demand growth slows or reverses in future.

These scenarios are conceptually illustrated in the following figure for a generic network asset. In practise, this approach would apply equally to either a feeder thermal rating or a zone substation N-1 transformer rating.

[4] Refer SOP17-17: Electricity Network Summer Preparedness Cycle

1. Base Case
Augment once energy at risk due to asset overload reaches economic trigger point.

2. Reduce risk of overload
Network support used to avoid asset overload and/or reduce Energy at Risk until augmentation is economic.

3. Defer augmentation
Network support used to avoid asset overload and/or reduce Energy at Risk to delay the point at which augmentation is economic.

4. Avoid augmentation
Network support used to defer augmentation that may not be needed if demand growth slows

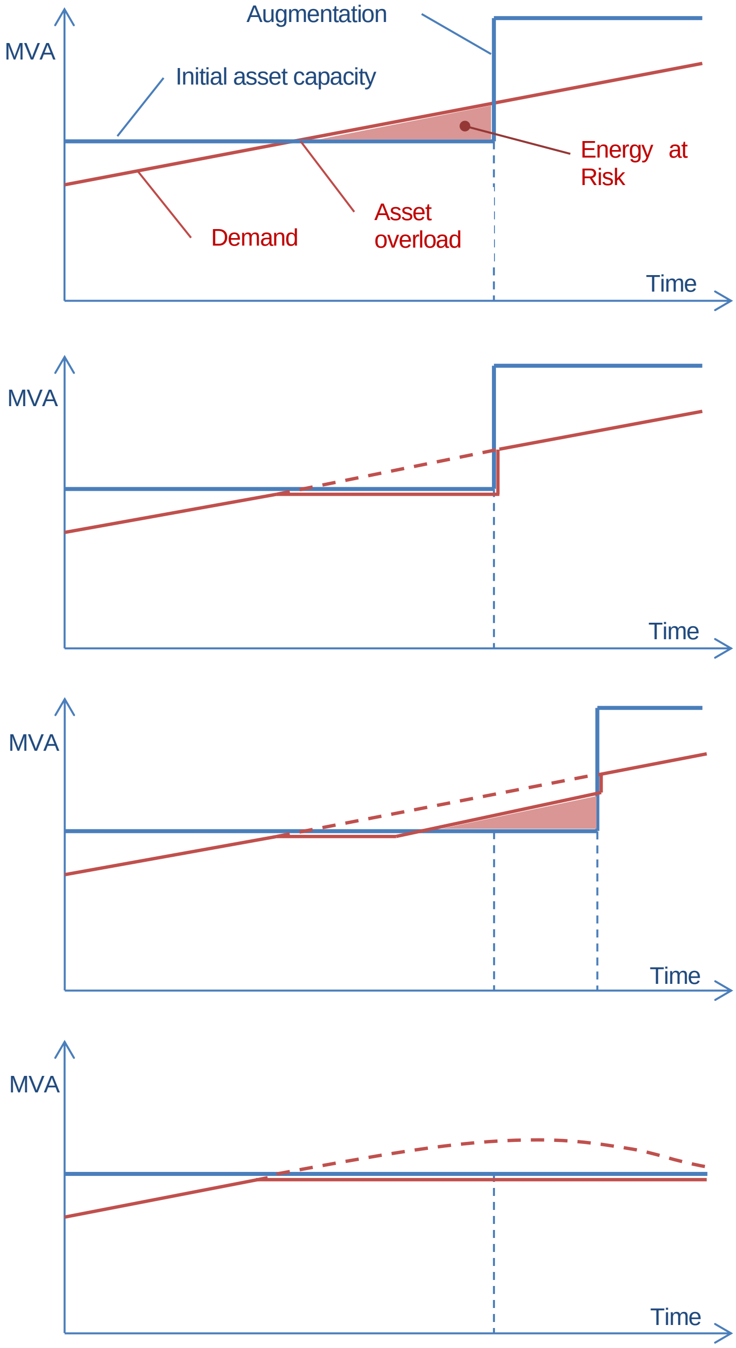

Figure 1 - Conceptual application of Network Support Services

The most direct application of Network Support Services is to defer capacity-driven investment; however they can also be used to defer asset replacement investment by reducing the level of EaR associated with failure of the asset in question. AusNet Services are currently investigating the practical value that network support can provide in these situations as the value proposition is often significantly different. For example, if failure of an asset is associated with a high public safety risk compared to value of EaR, then network support may not alter the investment timing.

2.3 Network support options currently deployed

Throughout the 2016-2020 regulatory period, AusNet Services has strengthened and structured its suite of Network Support Service options that are deployed either in production or in field trials. Each option has its own cost, applicability and firmness and should be assessed for viability against traditional network investment options on a case by case basis.

A qualitative overview of the options available is presented in the following table, and contrasted against the traditional network solution and the critical peak demand tariff. Green indicates a preferable attribute and red indicates a negative attribute.

The relative costs of different options will depend heavily on the duration of support required and the number of times it is needed per year. The cost line in the table below assumes a typical summer feeder peak that lasts approximately 4 hours and occurs on average 5 times per year.

Option	Network investment solution	Critical peak tariff	Network Support Services				
			C&I DM (EG)	C&I DM (curtailment)	EG temporary	EG permanent	Battery Storage
Cost	High	Low	Med	Med	Med	Med	High
Duration	High	Low	High	Low	High	High	Med
Asset focus	High	Low	High	High	High	High	High
Firmness	High	Med	Med	Low/Med	Med/High	Med/High	Med/High
Flexibility	Low	High	High	High	High	Med	Med
Experience	High	High	High	High	High	High	Med

Table 1 – Comparison of Network Support Services options to network investment and tariff options

Key messages from this comparison are:

- Compared to the traditional network investments, properly targeted Network Support Services offer increased flexibility at equal or lower cost.
- Load curtailment and storage options have limited durations of support.
- Optional price-based instruments (CPD tariff and C&I DM contracts) have lower firmness.
- AusNet Services has varying levels of experience in applying different Network Support Services.

Each option is described in detail in the following sections with case studies provided in Appendix 1.

2.3.1 Network-wide demand management

Initiatives that aim to manage demand across the entire network are generally not considered as Network Support Services as there tends to be a low level of certainty about demand reductions in the particular areas of the distribution network that are constrained. However, network-wide initiatives form an important and often complementary backdrop against which Network Support Services are considered and implemented.

Tariffs offer one avenue for network-wide demand management. Most tariff structures, time-of-use tariffs included, do not target specific peak demand days, but in 2011 AusNet Services introduced the more targeted Critical Peak Demand (CPD) tariff, applicable to large customers that consume more than 160 MWh per annum. The CPD tariff allows AusNet Services to nominate 5 peak demand days across the summer peak period. A customer's average peak demand during the 3pm to 7pm AEDT period across these 5 days is used to calculate the CPD component of the annual network charges for that customer for the following year.

Customers are provided with at least 24 hours advance notice of declared CPD days and are free to choose whether or not to reduce demand in order to reduce their demand charge in next year's tariff. Whilst individual responses cannot be predicted accurately there has been a reliable aggregate response to the tariff. Analysis undertaken in 2019 indicated:

- 2.5% reduction in demand across the network (~30MW)
- 84% of customers responded to the CPD tariff (2,252 of 2,696 customers on CPD tariffs)
- ~350 customers reduced demand by over 40%, and some customers cut demand completely

The aggregate response to each CPD day for a selection of large customers is shown in the following figure.

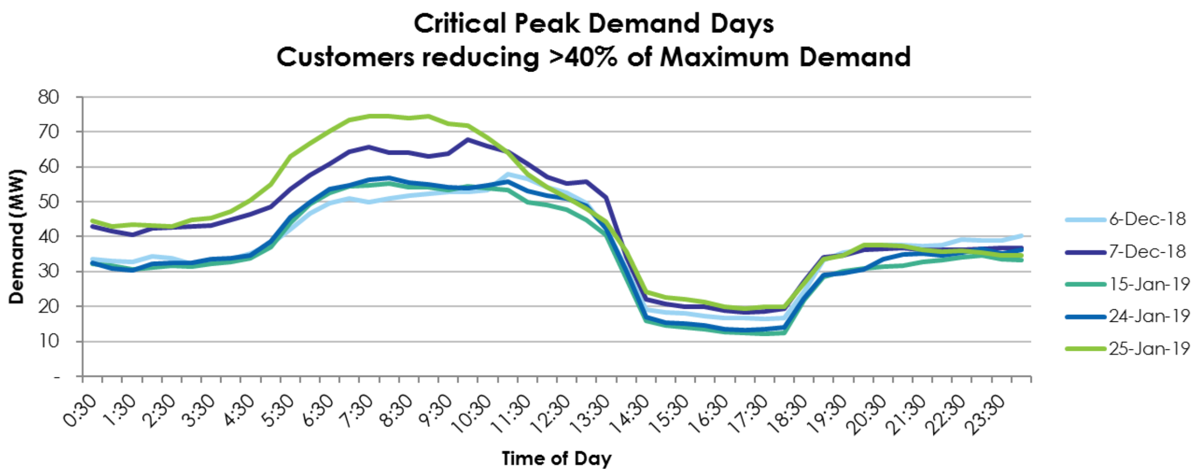

Figure 2 – Aggregate consumption profile of the 350 sites that had a 40 per cent plus reduction in peak demand on Critical Peak Demand days

At the residential & small business scale, tariffs involving peak and off-peak rates have been a long-standing offering to encourage customers to voluntarily shift loads. The introduction of three-part time-of-use tariffs in 2013 has increased the price signal between peak and off-peak times, however the tariff is currently voluntary and uptake has been low. Tariffs that include critical peak components have not been offered to small customers, however the merits of including this on tariffs that already include some form of demand charge (e.g. NASN class) are under investigation.

Other network wide initiatives include:

- Providing customers with greater access to energy consumption and cost information through the *myHomeEnergy* web portal.
- Providing energy conservation information to customers on the corporate website

Apart from driving high level consumption trends, the main area where network-wide demand management initiatives impact network support services is the interaction of the critical peak demand tariff with C&I DM network support agreements. Because both mechanisms are price-based incentives, there is a risk of double-counting if both were called on the same day. Therefore, C&I DM is not dispatched on CPD days. Although this avoids the risk of double-counting, it increases the risk that feeder-specific C&I DM dispatch does not occur on the highest peak days and could limit the full benefits of the C&I DM contracts being realised.

2.3.2 Asset specific Commercial & Industrial Customer Demand Management

Under the annual network planning process, P10 and P50[5] peak demand capacity risks are identified at 22kV feeder level by the Network Strategy and Planning Team. Once network areas with peak demand risks have been identified, a DM study is carried out to identify the magnitude and timing of the peak, its historic record and the suitability of C&I DM to address the risk reliably. In the event that there is sufficient penetration of C&I customers who have correlated and moveable demand, these customers are contacted to enquire if they wish to voluntarily take part in the DM programme.

The C&I customer is then offered a non-binding Network Support Agreement (NSA) that pays a dispatch fee.

- This fee is paid per kWh based on a customer's performance to a network event. A customer's performance is determined by comparing their metered demand during a network event to the predicted baseline profile[6]. Payments are made retrospectively upon validation of performance and invoicing by the customer.

2.3.3 Commercial & Industrial Customer Demand Management portfolios

AusNet Services established a portfolio of DM participants in each of its three service regions (North, Central and East) for activation during the summer period, focussed in areas where P10 or longer term P50 capacity risks are expected. This strategy reduces the time required to prospect specific areas for C&I participation and provides a base-level of network support that can be called upon for response to emergency network situations, thus improving network resilience.

Manual dispatch, validation and control of DM participants during a network event constitute a time and resource intensive exercise. As the number of participants increase to a critical mass it may be advantageous to procure a technology solution or engage a service provider to manage network events on a portfolio basis. A technology-based solution can optimise the dispatch of customers based on network conditions and customer attributes and may also include a level of automation between AusNet Services and customer sites.

Expected benefits of adopting portfolio management technology include:

- Better integration with control centre operations by reducing the level of manual resources required to dispatch customers.
- Increased firmness of response by incorporation of automation technologies.

2.3.4 Embedded Generation – mobile, short term

AusNet Services is continuing prior practices of deploying mobile generation units, typically around 1MW units, across the summer peak period. Short term deployment of mobile generators is often used where C&I DM is found to be either unavailable or insufficient to effect the required level of peak demand reduction.

[5] P10 and P50 refer to load levels that respectively have a 10% and 50% probability of being exceeded in any 1 year.

[6] Baseline profile means the predicted level of customer demand during a network event, had they not taken part in the event. This is usually defined as the top 5 demand days occurring in the 10 days prior to notification of a network event, excluding weekends, public holidays, CPD days and other network events.

Figure 3 - Two sets of 1MW diesel generators and transformers supporting the BN1 feeder.

Mobile generation units have been traditionally hired on a short-term basis and connected at 22 kV and 400 V to manage high-temperature initiated feeder demand that was forecast to occur on two to five days over the summer peak period.

In order to improve flexibility and coverage, AusNet Services has procured a fleet of four 1 MW diesel generation sets that can be deployed and connected at 22 kV or 400 V for feeder support during the summer peak or to minimise the customer impact of planned outages.

To minimise costs, preference should be given to use of the AusNet Services fleet of generators rather than hired generators, particularly when the generation unit is required for an extended period.

AusNet Services is also developing short term forecasting methodologies that may improve the logistics and flexibility of the AusNet Services generation fleet.

2.3.5 Embedded Generation - medium scale

Semi-permanent 5 MW to 10 MW power stations are available in the market for network support where their primary purpose is leveraging the NEM wholesale market price as non-scheduled price takers as well as ancillary services markets.

Figure 4 - Traralgon Power Station comprising 5 sets of 2 MW gas fired reciprocating engines

This size of facility is most suited for connection at zone substation level. The particular zone substations with energy at risk are identified to proponents in the DAPR each year from which a three to five year network support agreement can be negotiated.

Agreements usually specify a number of MWh to be made available over the summer period, or in emergencies, to provide peak demand management or to mitigate transformer failure risk exposure for the zone substation.

The following process is used to contract for support services:

A. Distribution Annual Planning Report (DAPR) issued in December every year providing details of current and forecast network constraints
B. Expression of interest (EoI) for network support / non-network solutions issued early in the next financial year
C. Commercial negotiations (term sheet) and Network Support Agreement concluded around June
D. Commissioning of power station and availability to provide Network Support by start of December

In 2012 AusNet Services successfully negotiated with a non-network provider to install 10 MW of gas-fired embedded generation at Traralgon, deferring the augmentation of a new 220/33 MVA zone substation transformer for at least five years. This project became operational early in 2013.

2.3.6 Embedded Generation – large scale

Large permanent power stations of over 10 MW can be used to support the 66 kV sub-transmission network. In a similar fashion to medium scale power stations, a contract is entered into that usually specifies the number of MWh to be made available over the summer peak period, or in emergencies, to provide peak demand management and offload the constrained network segment. Such projects may be viable alternative options to reconductoring or augmenting capacity in 66 kV loops, or to building new terminal stations or transmission lines.

AusNet Services currently contracts with one such large power station, the 94 MW Bairnsdale natural gas turbine station, to provide up to 40 MW of network support until March 2020. This contract makes up the bulk of AusNet Services' current portfolio of network support. The contract avoided the need to construct 110km of transmission line from Jeeralang to a proposed terminal station at Bairnsdale at an estimated cost of [C.I.C] (1997).

2.3.7 Storage

Storage – grid interactive residential

Customer-driven uptake of residential energy storage is forecast based on a combination of reducing battery costs, commercialisation of storage packaged with solar PV, increasing opportunities for energy arbitrage by leveraging flexible tariffs and the increasing penetration of electric vehicles.

Existing solutions for this technology predominately sit behind the meter and are not designed as a tool for the utility to use to any observable effect on the network. However if sufficient numbers are installed, or an energy aggregation control facility is implemented, there could be a value proposition for both the utility and the end-use customer.

Demand side participation with grid connected storage is being trialled by AusNet Services to understand how it might affect domestic demand profiles, what the network consequences are and whether it can be used to effectively manage peak demand. This trial of ten battery & inverter systems was run over two summers (2013/14 and 2014/15) and provided comprehensive data sets that improved our network modelling capability and informed our future storage strategy.

Figure 5 - Example residential battery storage system with 6.6kWh storage

Typical commercially available residential battery storage systems have power outputs of around 2-5kW and storage capacities of 2-20kWh. Some systems are designed to shift a small proportion of solar production to peak times to minimise solar exports, whereas other larger systems are designed to allow predominantly grid-free operation, with grid imports only required occasionally.

Storage - Grid level

Battery storage can also be applied at the grid level, such as to support a 22kV feeder or a zone substation during peak load times. In this application storage is effectively operating in a similar fashion to mobile generation, except that it will be adding to load at off-peak times in order to re-charge.

Figure 6 - Example layout of a grid-scale battery storage system with generator backup (image courtesy of ABB Australia)

Currently the cost of battery storage is significantly greater than embedded generation, however costs are continuing to reduce and there is an expectation that cost-competitiveness will be reached around five years' time. There are also niche applications where storage may prove economic at present, such as managing voltage and balancing output from renewable EG.

Grid-level storage is relatively modular and can be procured in a range of sizes from 10s of kW up to several MW, with all ranges of kWh to MWh in capacity. Battery chemistries tend to be either lead-acid or lithium-ion, where the optimum chemistry depends on the balance required between power and capacity, however lithium-ion chemistries have emerged as the most prevalent among battery manufacturers in the grid storage space. There is also active research and commercialisation in alternative chemistries.

A particular issue for the use of storage by a DNSP is the regulatory constraints in terms of consuming energy and supplying energy as the battery is charged and discharged. Whereas embedded generation effectively provides its output to the local retailer by default, storage requires a retail agreement for supply and sale of the energy. There is likely to be a commercial benefit to the retailer in terms of energy market arbitrage when deployed with an agreement with a retailer or aggregator.

2.3.8 Controlled load management

Since the early 2000's AusNet Services has undertaken a series of projects to address overnight demand peaks caused by the simultaneous switching of many time-switch controlled loads such as hot water and slab heating systems. Although generally considered more of a network demand management measure than a network support service, the technique is relevant in considering the suite of available options.

Depending on the specific tariff, controlled loads would typically switch on at 11pm or 1am. This was found to be a particular problem throughout Gippsland. As well as causing localised feeder peaks, the issue was found to cause voltage collapse on the 66kV South Gippsland Loop and cause loads to exceed the N-1 thermal rating, therefore increasing significantly the risk of load shedding. A program was undertaken to randomise time clocks in the following locations:

- Phillip Island
- Leongatha
- Wonthaggi
- Foster

In combination with the installation of capacitor banks, this program deferred the need to re-conductor section of the South Gippsland Loop for several years.

More recently, randomisation of time clocks was undertaken at Mallacoota to reduce the peak demand levels that a backup generator would be required to serve. The location of Mallacoota at the end of a long and forested radial 66kV and 22kV line exposes it to the risk of multiple day outages. In these situations temporary generation is deployed to serve the Mallacoota community, and it is important to manage peak demand to within the capability of the generator.

The adjustment of time-clocks remains a viable demand management practice and there may be further needs to initiate such projects. Dual-element AMI meters are currently set with a randomisation function to switch on dedicated loads between 11pm and 12am, with a hard-stop at 7am. These settings should result in peak demand reductions compared to synchronised mechanical time switches. Once complete, the AMI network will also allow time switch settings to be adjusted remotely and fine-tuned if required.

2.4 Future Network Support Options

AusNet Services has identified residential demand response as a key area in which to develop future network support capability. The introduction of advanced metering technology and availability of third-party aggregation services have opened up the prospect of addressing residential peak demand at-source.

Potential measures include:

Tariff-based measures: In a similar fashion to the large customer critical peak demand tariffs, it is possible to structure network-wide tariffs for residential customers that contain a critical peak element. Other structures include the “three-colour” tariff structure. Critical peak tariff structures for small customers have been proven to be effective in a number of small scale trials. However, any tariff based measures would require regulatory approval and would likely face significant regulatory scrutiny.

Critical peak-demand rebates: In a similar fashion to C&I DM contracts, DNSPs can offer rebates to customers in a constrained part of the network if they can reduce their consumption compared to their historical baseline usage during peak times. This technique has been tried by other Australian DNSPs and has been found to be effective. A rebate may be easier to administer for C&I customers in the NASN-tariff classes, instead of pursuing regulatory approval of a full tariff change.

Demand Response Enabled Device (DRED) controls: The Australian Standard AS4755 is being developed to allow a common method for DNSPs to control certain high usage consumer appliances to provide network support. Commercial application could be through direct contracts with customers, through third-party aggregators or through the terms of connection agreements. Residential battery storage could also be controlled via a DRED.

Demand limiting via smart meters: Smart meters have the functionality to control the demand level at which customers are disconnected. It is technically possible to utilise this function for network support in emergency situations, although there will be regulatory hurdles in application.

Embedded generation: Customers with embedded generation can not only reduce their own demand on the network but can further support the network by increasing EG exports at peak demand times if incentivised appropriately. Therefore, financial-based measures such as tariffs and rebates would need to have an equivalent feed-in tariff component in order to incentivise a normally-exporting EG customer.

AusNet Services intends to engage further in this area of residential demand response.

Other technologies that have been identified as potential future options for network support include thermal storage in building cooling systems, high-efficiency cooling systems such as ground-source heat pumps and fuel cells that could offer network support generation with lower emissions of greenhouse gasses and noise compared to diesel generation.

2.5 Framework for assessment

When developing a business case to address an identified network need, network support options should be developed in parallel with network investment options and considered equally on both technical and economic grounds. Where technically viable, network support options are often lower cost than network investment options; however there may be over-riding constraints such as timing requirements.

In terms of procuring Network Support Services in practice, AusNet Services has documented its approach in a Demand Side Engagement Strategy published on AusNet Services’ website. This document sets out the way that AusNet Services engages with providers of Network Support Services and the principles governing the level of payments that can be offered.

Under the regulatory framework, distribution businesses are required to provide network support payments for non-network projects which maximises the net economic benefit associated with mitigating a network constraint. In practical terms, application of this principle to the development of payment levels for network support services are generally based on the reduction in expected unserved energy that the service offers, priced at the Value of Customer Reliability (VCR)[7]. This provides a 'cap' for recovery of the costs for non-network projects (and hence network support payments) and allows assessment of whether any network support options are cost effective.

When assessing the Network Support Service options for a particular constraint, it is important that the specific characteristics of the constraint are defined in order to compare with the relative performance characteristics of the various options.

The constraint characteristics include:

- Magnitude – load at risk (MW)
- Duration – total hours at risk, as well as the number of hours at risk for individual constraint events
- Probability – the number of times that the constraint event is likely to occur

This analysis requires interrogation of the load forecasts and the historical load data for the particular network element as well as condition related data including the probability of asset failure.

C&I Demand Management

Given that C&I DM is generally the lowest cost option for short-duration constraints, this should be assessed first to determine viability.

Current NSA's for C&I DM are structured around five days per year provision of around four hours of load reduction. If, for example, the constraint is found to be likely to occur for 20 days across the summer peak, or for up to 12 hours duration, C&I DM is unlikely to be appropriate as a solution except where:

- C&I DM can still reduce the value of energy at risk and potentially operate alongside another Network Support Service such as EG; or
- A C&I customer has on-site EG and can offer a higher duration and frequency of network support.

Potentially suitable C&I customers can be identified through desktop analysis of customer load profiles compared to asset load profiles. Whether or not a customer is willing to enter a network support agreement, and whether they have on-site EG that is suitable for DM can only be discovered through direct customer engagement.

Embedded Generation / Battery storage (Non-Network Solutions)

After the DM investigation is conducted, non-network solutions can be assessed as further or alternative options. Given the current higher costs of storage versus EG, storage is unlikely to be competitive except in certain circumstances such as:

- Where part of the funding can be obtained through other revenue streams or paid for by other parties. This could be the case where a retailer or customers can extract energy arbitrage value from the system.
- Where the capacity factor (energy to capacity ratio) is very high. For example if the number of hours of run-time is very high, the cost of diesel fuel becomes considerable and a battery may be more cost effective than a diesel gen-set provided that the battery has opportunity to recharge at off-peak periods.

For larger-scale network support (>2MW), expressions of interest are likely required in order to test the market appetite for permanent or semi-permanent non-network solution development.

[7] VCR as set by the Australian Energy Market Operator

The above process will output the credible network support options as illustrated in the following flow-chart.

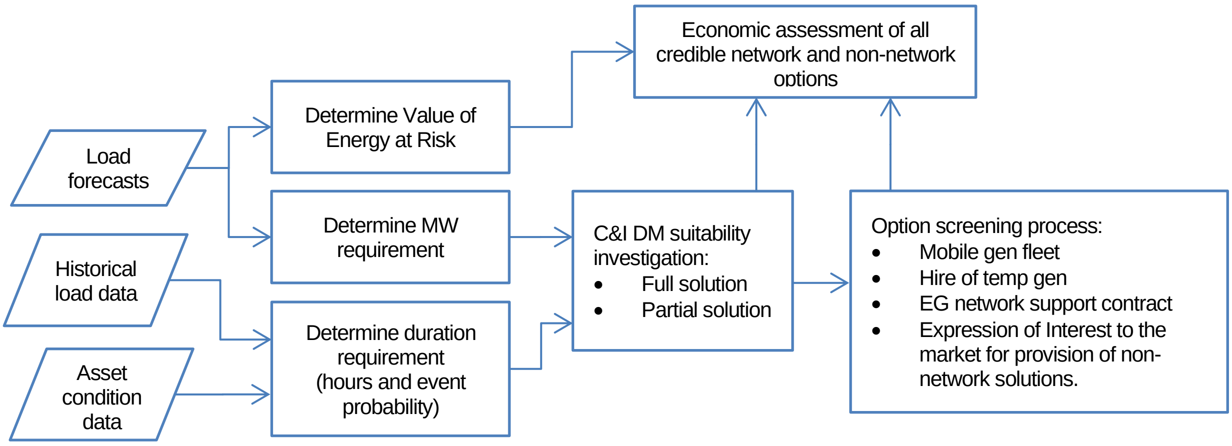

Figure 7 - Process to develop Network Support Service options

The network support options should then be compared on economic grounds against the identified network investment options within the context of other constraints such as timing requirements.

The RIT-D process does not apply to projects that are required to address urgent or unforeseen network issues or are justified purely on asset replacement grounds, however, network support options should still be assessed during the project planning and business case phases. Although typically more aligned to deferring capacity-driven projects, network support services also provide value in asset-replacement projects. For example the replacement of zone substation transformers that are in very poor condition will not trigger RIT-D; however network support could potentially be used to reduce the level of energy at risk until the replacement is completed, or to defer the point at which the replacement is economically justified.

3 Drivers and Strategies

There are several commercial and regulatory drivers that are acting in combination to increase the competitiveness and priority of Network Support Services as an alternative to traditional network investments. In response, AusNet Services has developed strategies to investigate new network support options, integrate innovative techniques into the rest of the business and to build an increasing level of contracted network support across the distribution network in targeted areas.

3.1 Commercial drivers

The primary commercial drivers promoting the use of Network Support Services include the:

- increasing uncertainty in long term electricity demand forecasts;
- increasing cost of network augmentation and replacement projects;
- increasing availability and decreasing costs of network support technologies;
- operational flexibility in timing, scale and location of Network Support Services ;
- fixed nature of network investments and long cost/benefit break even times; and
- regulatory incentives (covered in Section 3.2).

3.1.1 Uncertain long term electricity demand forecasts

In an environment of slowing peak demand growth and less certainty about long-term demand growth trends, there is an increased risk that network augmentation projects provide a level of capacity that is surplus to requirements over the lifetime of the asset. Network support options have shorter timeframes than network investments and can therefore be scaled to shorter-term needs and reduce the risk of long-term overinvestment. In extreme cases, it is possible that peak demand on a network section may increase in the short term but fall over the long-term. In this case, Network Support Services can be discontinued, within the bounds of contractual arrangements, whereas the cost of expenditure on network augmentation continues for the economic life of the asset.

3.1.2 Cost of network investment projects

Due largely to simultaneous demand in customer connections and replacement of deteriorating network assets in several Australian states, the costs of electricity network augmentation and replacement costs have risen in recent years. Under the probabilistic planning criteria used in Victoria, increased augmentation & replacement costs expose DNSPs to higher values of EaR for longer periods of time before network investment can be justified.

The relatively peaky nature of load duration curves in Victoria means that additional network capacity is often required for a relatively short period each year. Accordingly, generation can often resolve or mitigate capacity constraints at lower present value costs compared with network augmentation.

3.1.3 Availability and costs of network support technologies

Some mature network support technologies such as temporary and permanent generation have remained relatively stable in terms of cost whereas others such as storage and DM aggregation have become more widely available and at a lower cost.

Battery storage is on a declining cost curve and commercial products at both grid-scale and customer scale is also more widely available. The recent advances in smart-grid communications technology and cloud computing have enabled lower cost services that aggregate and coordinate distributed energy resources. Such aggregation can increase the firmness and flexibility of demand side options including both demand management and embedded generation.

3.1.4 Operational flexibility

The scale-able nature of Network Support Services such as DM and non-network solutions offers the opportunity to address capacity constraints at lower values of energy-at-risk and to progressively address increasing values of risk over time. This scale-able nature offers the DNSP greater flexibility in deciding the quantum of energy-at-risk at any particular site or across the network.

Locational flexibility is afforded by DM and the smaller scale generation and storage technologies, allowing the DNSP to target different areas as network conditions change. Whilst network connection infrastructure such as switchgear, protection, SCADA, earthing and civil works can be viewed as a sunk cost, the generation or storage units themselves are re-locatable as well as being scalable. Thus a proportion of generation installations can be scaled to closely match variations in network capacity, reliability or quality of supply constraints and a significant proportion of the installation can be relocated to manage constraints in alternate locations such as seasonal peaking demand in different geographic locations. Likewise, DM contracts can be established or expired with customers in different locations to respond to changing network conditions.

Time-based flexibility is particularly important in the context of slowing peak demand growth and uncertainty in demand forecasts. The use of short-term Network Support Services gives an option value to a DNSP to avoid the risk of long-term fixed assets becoming stranded in the event that peak demand growth significantly slows or reverses.

3.1.5 Fixed nature of network augmentations

Compared to the relatively flexible nature of Network Support Services, network augmentations tend to be large, fixed in scale, fixed in location and long term. This means that it is difficult to scale a network augmentation in respect of future demand and that there is often a long pay-back period before the benefits of the augmentation exceed costs. The long operational lives of network assets also results in uncertainty around the magnitude and timing of disposal costs. Most network augmentation assets cannot be relocated, and even the more modular items of plant (voltage regulators, cap banks etc.) would incur significant costs in removal and re-installation.

3.1.6 Risk implications

Network Support Services such as DM or non-network solutions have a shorter life and higher risk profile than network augmentation options. The higher risk profile arises from a reduced level of “firmness”: a generator may not start when required, a battery may not have been scheduled to be at full state-of-charge, or a DM customer may choose not to participate in a particular network event. The risk profile needs to be considered in the business case for a particular project.

3.1.7 Network expenditure implications

An important commercial implication of increased deployment of Network Support Services as opposed to network augmentation is that some network expenditure will move from CAPEX to OPEX. This needs to be considered when undertaking economic assessment of different options and when forecasting expenditure requirements.

Network support expenditure likely to be classified as OPEX includes:

- Cost in prospecting for non-network solutions
- Network support payments
- Procurement of DER aggregation services
- Hire of non-network solutions
- Procurement of network support from medium scale generation or storage providers.

Some Network Support Service expenditure is also likely to be able to be capitalised, such as:

- AusNet Services-owned fleets of generation or storage,
- Connection assets,
- Information systems required to manage network support.

3.2 Regulatory influences

DNSPs are subject to a number of regulatory requirements that aim to encourage the uptake of non-network solutions where they are the most cost-effective option. Central to this aim are the requirements stemming from the Distribution Network Planning and Expansion Framework that was concluded in 2012. Additional supporting, regulatory elements include the Demand Management Incentive Scheme and the development of rules around aggregation of small generation and demand side response.

3.2.1 Distribution Network Planning and Expansion Framework

In 2009 the AEMC undertook a wide-ranging review which recommended a number of reforms to the National Framework for Electricity Distribution Network Planning and Expansion.[8] The reforms have come into force across late 2013 and early 2014 under an AEMC rule change.

Under the Framework, the National Electricity Rules (NER) place new demand side obligations on DNSPs with the aim of encouraging efficient investment in network infrastructure for the long term interests of electricity consumers as required by the National Electricity Objective.

As shown in the figure below, the Framework comprises three interrelated components: a Distribution Annual Planning Report (DAPR); a Demand Side Engagement Strategy (DSES); and a Regulatory Investment Test for Distribution (RIT-D) process.

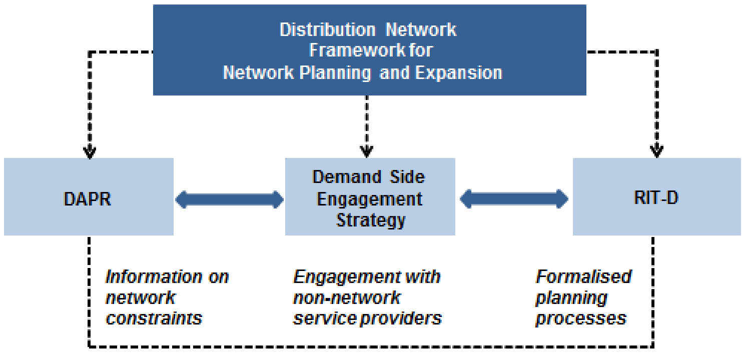

Figure 8 – Elements of the Distribution Network Planning and Expansion Framework

The DAPR is issued publicly in December of each year and the Demand Side Engagement Strategy was first published in August 2013. The RIT-D stipulates formal planning and consultation processes that DNSPs must follow when considering large scale investment to meet identified limitations or constraints on the network. Non-network options must be considered for augmentation projects greater than [C.I.C].

3.2.2 Distribution Annual Planning Report (DAPR)

The DAPR provides information on the AusNet Services distribution network over a forward planning period of five years and informs external stakeholders about emerging network constraints and the potential opportunities for provision of Network Support Services.

The DAPR documents the capacity of the network and system limitations for sub-transmission lines, zone substations and some heavily loaded 22kV feeders and possible options being considered to address these limitations. Information on our planned asset replacement work is included. Network performance in the area of power quality and reliability is covered as well as information on metering and information technology systems. Some information regarding planning for transmission to distribution connection points required by clause 5.13 of the NER is covered in the Transmission Connection Planning Report.

3.2.3 Demand Side Engagement Strategy

The Demand Side Engagement Strategy aims to facilitate co-operative engagement in network planning between AusNet Services and proponents of non-network solutions and Network Support Services. The strategy covers the approach that AusNet Services takes in:

- considering non-network options in the planning process
- engaging with providers on non-network solutions

[8] AEMC – Completed Rule Change: Distribution Network planning and Expansion Framework, Reference ERC0131.

The strategy includes the need for AusNet Services to maintain a register of Network Support Service providers and other parties that are interested in receiving notifications from AusNet Services regarding distribution network planning and expansion information. The register provides a mechanism for parties to receive timely information regarding network support opportunities and in order to provide solution proposals to AusNet Services.

3.2.4 Regulatory Investment Test for Distribution (RIT - D)

DNSPs must undertake an economic cost-benefit evaluation called RIT-D for all major augmentation projects where the estimated capital cost of the most expensive credible option to address the relevant identified need is [C.I.C] or more

The RIT-D process provides a framework for DNSPs to consider a range of options, including non-network solutions, to address the investment needs of the network. By performing a RIT-D, a DNSP would be able to identify the credible option (regardless of its technology) that maximises the net present value of all economic benefits that arise from the project. In this context, the RIT-D is intended to ensure that non-network solutions are considered equally on their merits as alternative options to traditional network solutions.

The RIT-D process is not required for investment needs that are urgent or unforeseen, negotiated services, replacements, customer connection services, or where the proposed investment has been identified through joint planning processes between DNSPs and TNSPs.

3.2.5 Demand Management Incentive Scheme

The revised Demand Management Incentive Scheme (DMIS) provides a revenue uplift of up to 50% for any OPEX spent on Network Support Services to defer or avoid a network augmentation. Application of the DMIS for non-network solutions is proposed for a handful of locations where constraints have been identified.

The related Demand Management Innovation Allowance (DMIA) provides funding for DNSPs to undertake projects that reduce network demand but may not be economically justified on their own merits. The DMIA is intended to build demand management capability and knowledge within DNSPs in order to reduce network costs to consumers over the long-term. AusNet Services received DMIA funding totalling [C.I.C] across the 2016-20 regulatory period.

Beyond just funding early stage or research-based projects, the DMIA can be used to partially fund demand management projects that address network constraints and avoid augmentation expenditure. In this situation, the portion of the project cost that is not economically viable may be eligible to receive DMIA funding.

3.2.6 Small Generation Aggregator (SGA)

The Small Generation Aggregator is a new category of participant in the National Electricity Market (NEM). The creation of this participant is to encourage small generators to participate in the NEM by reducing the entry barriers they face. As the commercial market around the SGA develops, it might provide more cost effective EG services to AusNet Services and give greater benefits to DNSPs to deploy EG.

3.2.7 Demand Response Mechanism (DRM)

The Ministerial Council on Energy is currently considering a new mechanism in the NEM that would allow demand response to compete head-to-head against generation in the wholesale spot market. Tied to this mechanism is the creation of a new category of market participant called a Demand Response Aggregator that can pool the resources of multiple demand response providers. This new mechanism might also stimulate increased activity in demand response which could be leveraged for network support. The currently proposed design of the DRM allows a single demand response action to receive both the wholesale market benefit as well as any network support benefit. By providing easier access to the wholesale market revenue stream, the DRM could increase the availability of low cost network support.

3.2.8 National Energy Customer Framework (NECF)

Victoria proposes to implement the National Energy Customer Framework (NECF), a national framework for the regulation of energy distribution and retail activities. For the most part, existing Victorian regulation will transfer across to equivalent NECF provisions when it is implemented, but there will be some changes that impact AusNet Services.

The NECF will introduce Chapter 5A into the NER to cover the connection of embedded generation. This will replace the existing Essential Service Commission of Victoria's Electricity Industry Guideline 15.

The NECF is not expected to impact AusNet Services' procurement of Network Support Services, although the full analysis of NECF impacts is still being undertaken by our regulatory functions.

3.3 Strategies for Network Support Services

To drive and govern the uptake of Network Support Services on the distribution network, AusNet Services has adopted a suite of strategies to:

- Strengthen its capability in the application of Network Support Services
- Increase the level of contracted network support
- Develop and formalise business processes to continue to deploy network support services whenever viable and economic
- Integrate new innovations into business as usual

Strengthened capability:

The proposal for the 2016-2020 EDPR[9] sets out the strategy to build a non-networks capability that focusses on demand management and network support options. The Distributed Resources and Innovation team provides this capability and acts to both develop network support options for the network planning functions and to trial new innovations in the demand management & network support space.

Economic deployment:

As outlined in AMS 20-01 Electricity Distribution Network, AusNet Services undertakes an economic assessment of technically viable options when considering a project investment, to ensure that expenditure is economically efficient. As part of this process, network support solutions are assessed against network solutions. To help ensure that third-party network support providers are informed and engaged regarding major network support opportunities, AusNet Services publishes a DAPR and a Demand Side Engagement Strategy and follows the RIT-D process as outlined in Section 3.2.

Integrate new innovations into business as usual:

The Distributed Resources and Innovation team is charged with driving innovative techniques and technologies, many of which are focussed on demand management and network support. To help facilitate the transfer of innovations into the wider AusNet Services business, an Integration Strategy has been developed that sets out the communications processes and integration pathway for key innovations.

[9] SP AusNet Determination 2011-15: www.aer.gov.au/node/7211

4 Appendix 1 – Case studies and Trials

This Appendix provides information regarding recent and current case studies in order to help inform the practical application of Network Support Services. It should be kept in mind however non-network solutions are rarely directly transferrable between different applications and that tailoring of solutions is generally required.

4.1 Traralgon Power Station - EG Network Support Agreement

AusNet Services established a Network Support Agreement with [C.I.C] that deferred investment in a 4^{th} transformer at Traralgon Zone substation. The five-year agreement commenced December 2012 and principally covered the summer support periods between December 1^{st} and March 31^{st} each year.

Under the agreement, [C.I.C] provided network support services from a 10MW gas fired embedded generator connected to AusNet Services' Traralgon (TGN) Zone Substation via an existing 22kV feeder (TGN 31) during the summer network peak loads periods.

The business case for the TGN Network Support Agreement is summarised below.

4.1.1 Identified need

Traralgon zone substation (TGN) supplies more than 16,000 customers in central Gippsland where the population growth continues at 1.6% p.a. and electricity demand growth averages 6% p.a.

Traralgon zone substation has a simple configuration with one 66 kV bus and one 22 kV bus. Faults within the station result in electricity supplies to all 16,000 customers being lost until the site can be attended and the faulted equipment is manually switched from service.

At the time, the TGN ZSS #2 transformer was ranked the sixth worst failure risk in the AusNet Services fleet and the #1 TGN transformer is ranked as the seventh worst failure risk.

The existing three 10/13.5 MVA transformers installed at TGN were loaded above their N-1 rating of 32.5 MVA. Energy-at-risk was calculated to be 2,131 MWHr for the summer of 2012/13 when the 50% POE load forecast was expected to equal the station transformation N rating of 49.1 MVA.

TGN loads and ratings are summarised the figure below.

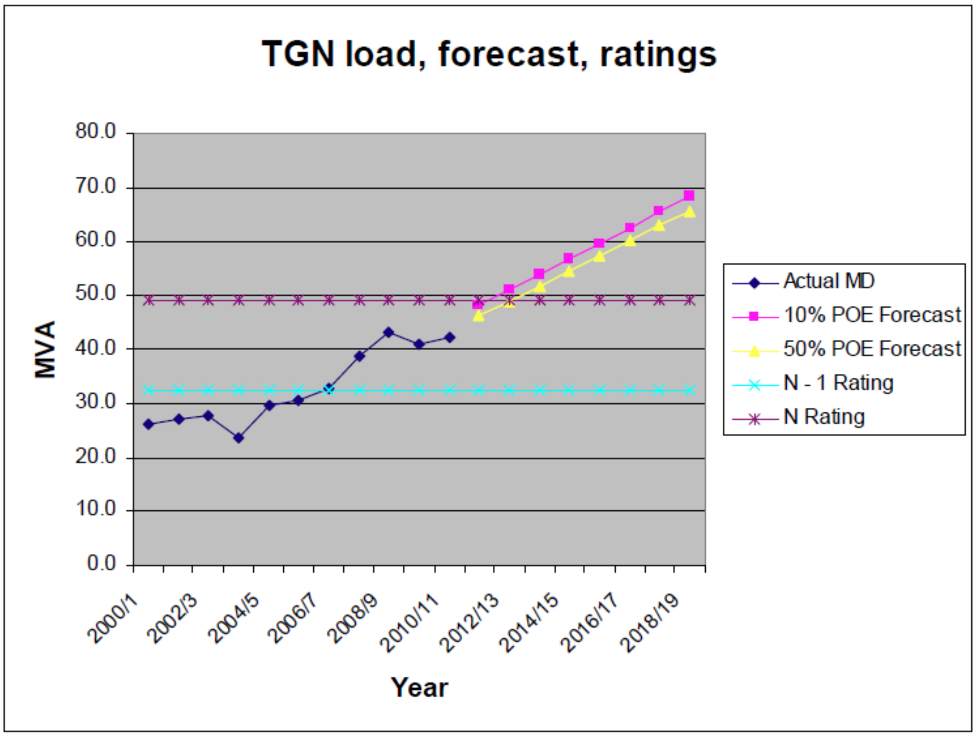

Figure 9 -TGN Loads, Forecast Loads and Ratings

4.1.2 Options

Six options were analysed to mitigate the energy-at-risk and S-Factor reliability penalties associated with plant failure including:

1. Do nothing
2. Engage 10 MW of network support
3. Replace the #1 transformer with a 20/33 MVA unit and contract 10 MW of network support
4. Install a #4 20/33 MVA transformer and remove one 10/13.5 MVA unit
5. Replace the #1 and #2 transformers with 20/33 MVA units
6. Augment the capacity of the MWTS 22 kV bus, create two new MWTS feeders and transfer load from TGN to MWTS

Option 1: Do nothing

Doing nothing was not viable as the 6% per annum growth in demand was expected to continue and significant customer inconvenience and large S-Factor penalties would be associated with the sustained outages if loads exceeded the station transformation rating.

Option 2: Engage 10 MW of network support

Contracting network support alone would not reduce failure risks to acceptable levels as the load at risk for summer 2012/13 is 16.5 MW (50% POE forecast). The simple configuration of TGN zone substation and the deteriorated transformer condition present significant S-Factor risks which would not be addressed by network support or a combination of network support and load transfers.

Option 3: Contract 10 MW of network support and replace the #1 transformer - PREFERRED

This option comprises the following: contract 10 MW of network support and replace the #1 transformer with a 20/33 MVA unit, install bus-tie circuit breakers and a 22 kV indoor switch board to create “full switching” and refurbish the existing control room to address all constraints at an estimated capital cost of [C.I.C] plus estimated network support costs of [C.I.C] (PV) over five years for provision of 4,000MWh of network support (nominally 800MWh per year).

This was the chosen option following an Expression of Interest and discussions with EG and DM suppliers. [C.I.C] are providing network support in the form of 10 MVA of natural gas fired generation located in an industrial estate approximately 1 km north of TGN.

Option 4: Install a #4 transformer and remove one 10/13.5 MVA unit

Install a #4 transformer (20/33 MVA) and remove one poor condition transformer, install bus-tie circuit breakers and a 22 kV indoor switch board to create “full switching” and refurbish the existing control room to address all constraints at an estimated capital cost of [C.I.C].

Option 5: Replace the #1 and #2 transformers with 20/33 MVA units

Replace the #1 and #2 transformers with 20/33 MVA units, install bus-tie circuit breakers and a 22 kV indoor switch board to create “full switching” and refurbish the existing control room will address all capacity and equipment condition constraints at TGN at an estimated capital cost of [C.I.C].

Option 6: Augment MWTS 22 kV buses create two new MWTS feeders and transfer load

Augment the capacity of the three 22 kV busses at Morwell Terminal Station (MWTS), create two new 22 KV feeders and interconnect with two existing TGN feeders to increase the load transfer capability between TGN and MWTS. This option addresses all network constraints but has the highest capital cost [C.I.C]. This option offers the least strategic value as load is growing to the east and the north of Traralgon and MWTS is located some 10 km to the south.

4.1.3 Economic assessment

The prevailing AusNet Services NPV financial model was found not to be well suited to the evaluation of non-network options to resolve network constraints.

In particular the model does not clearly define the benefit of deferring capital expenditures within the prevailing regulatory period. Also lacking is the capability of modelling the use-it-or-lose-it funding component of the Demand Management Innovation Allowance.

Nevertheless, there is a clear benefit associated with Option 3 which replaces one 10/13.5 MVA transformer and defers the replacement of a second transformer by engaging 10 MW of network support for a period of five years. This is summarised in the following table.

C.I.C

4.1.4 Commercial terms

The Network Support Agreement is structured around the provision of 800 MWh of network support per year. Unused MWh in any year is accrued into the next year to give a total of 4,000 MWh over 5 years. The base network support payments are as follows:

Charge	Year	Amount
Initial Payment		[C.I.C]
Commissioning Payment		
Network support charge Year 1	2013	
Network support charge Year 2	2013/14	
Network support charge Year 3	2014/15	
Network support charge Year 4	2015/16	
Network support charge Year 5	2016/17	
TOTAL over 5 years		

If additional network support beyond the 4,000MWh is required, additional MWh are charged at approximately [C.I.C].

4.2 Bairnsdale Power Station – EG Network Support Agreement

A long term agreement was established with [C.I.C] to provide up to 40 MW of network support to maintain the security of the East Gippsland 66kV network through an embedded generator at Bairnsdale.

Although the Bairnsdale Power Station continues to provide critical network support to AusNet Services, the regulatory environment has changed significantly since the agreement was established in 1998. Therefore, while it is important for general context, the Bairnsdale Power Station agreement is not considered a useful template for establishing future agreements

AusNet Services' Bairnsdale Switching Station (BDSS) interconnects five 66 kV lines with the two generation units at Bairnsdale Power Station (BPS) and a Static VAR Compensator (SVC), also owned by [C.I.C]. This infrastructure was established in 1998 as an alternative to the construction of 110 km of transmission line from Jeeralang terminal station to a proposed terminal station at Bairnsdale at an estimated cost of [C.I.C] (1997).

BPS now has two 47 MW natural gas fired turbine generators. The first of these, Unit #1 has been contracted to provide network support until 2021. Unit #2 was installed as a market generator, and avoided Transmission Use of System (TUoS) charges are calculated on the volume of production from Unit #2 on the 10 peak demand days nominated by AEMO.

4.2.1 Network Support Agreement

The Network Support Agreement began in July 1998 and was priced at a marginally cheaper rate than the network augmentation cost. The agreement contains a schedule of charges for the period of the contract until 2020. The agreement was amended in April 2000 and then again in Dec 2004.

The current agreement specifies that at least one generator and the SVC must be available for service at all times. There is an annual entitlement of 82,700MWh of network support which AusNet Services can draw upon during the current Basic Plant Dispatch periods of:

- 18:00 Hr until 03:00 Hr up to 40MW for 5 Hours, and
- 14:00 Hr until 22:00 Hr up to 20MW for 4 Hours

The current agreement includes an annual At Large entitlement of 2,400 MWhr upon which AusNet Services can draw at any time.

The prevailing network support agreement preceded the current requirements of Electricity Industry Guideline No. 15[10] where a distributor is required to pass through a share of the

[10] Electricity Industry Guideline 15 Connection of Embedded Generators Issue 1 August 2004 Essential Services Commission, Victoria

avoided distribution network system costs to an embedded generator. ***Therefore, this agreement is not a useful model for establishing future agreements as new obligations have been established for calculating avoided costs and sharing the benefits between the embedded generator and customers.***

4.2.2 Agreement Operation

AusNet Services pays around [C.I.C] per year for the base network support provision. Some years require an additional payment for excess At-Large MWhs.

Regulation and Network Strategy (RNS) provide [C.I.C] with a distributor monthly dispatch schedule for network support one month in advance.

The Customer Energy and Operations Team (CEOT) provide [C.I.C] with the distributor dispatch schedule which amends the monthly schedule in accordance with immediate operational needs. The network support budget is held by CEOT who validate the monthly network support invoices received from BPS.

The Base Support component of the east Gippsland network support payments are made monthly in accordance with Schedule 4 of the agreement. Invoices for network support, in excess of the At Large entitlement, are calculated according to Schedule 3 of the agreement and payment is made monthly.

In recent years avoided TUoS payments have varied between [C.I.C] and [C.I.C] per annum. Regulation and Network Strategy initiate these payments annually, in arrears, following reconciliation with the 10 maximum demand days nominated by AEMO and subject to endorsement by the AER.

As a market participant, BPS generates for commercial benefit. Nevertheless, AusNet Services must still schedule its network support requirements even if BPS is already generating to avoid an unanticipated reduction in generation. Subject to available resources CEOT can analyse the operating behaviour of BPS and elect not to draw down the At Large entitlement when BPS is already generating.

The agreement is due to expire in March 2020.

4.3 Euroa – BN1 Temporary generation (Initiated 2010)

The BN1 22 kV feeder supplies approximately 4,380 customers in Violet Town, Euroa and surrounding areas. It is AusNet Services' longest feeder with 1,160 kilometres of predominantly overhead line with a 47 kilometre long backbone from Benalla to the major load-centre at Euroa.

Options for addressing the emerging network constraints on the BN1 feeder were quantified as part of the 2011-15 EDPR final submission.

4.3.1 Risks and immediate mitigation

Three pole mounted capacitors were installed in recent years to minimise the loading on this feeder due to rising losses. The nominal summer rating of 180 amps (6/1/.186 ACSR conductor @ 50_0 C) was increased to a summer cyclic rating of 285 amps by increasing the conductor clearances in critical spans between Benalla and Euroa.

In recent years, immediate risks of thermal overload and associated voltages falling outside the Electricity Distribution Code allowance have been managed by power factor correction, the installation of temporary generation and risk management of substandard ground clearances in specific spans

4.3.2 Options

Five options were considered to address the increasing frequency and severity of thermal overloads on the line and its two voltage regulators and operating voltages outside those specified in the Electricity Distribution Code including:

1. Do nothing
2. Reconstruct the line between Violet Town and Euroa to future 66 kV with 22 kV subsidiary construction and upgrade 22kV regulators,
3. Temporary diesel power station at Euroa.
4. Permanent gas fired power station at Euroa
5. Demand reduction

Option 1: Do nothing

Doing nothing is not viable as the 2 to 3% per annum peak demand growth of recent years is expected to continue with the following impacts:

- Circuit to ground clearances will not meet the requirements of the Electricity Safety Management Scheme as approved by Energy Safe Victoria.
- Voltage regulators will be damaged or fail due to increasing extent and frequency of overloads.
- Voltage levels to customers will transgress the requirements of the Electricity Distribution Code.

Option 2: Augment BN1 feeder capacity

The long term network planning for the Violet Town and Euroa area includes the option to construct a new zone substation at Euroa. This will include augmentation of the existing BN1 feeder between Benalla and Euroa to 66 kV and 22kV multi-circuit configuration. Network demand can be met through to 2015/16 summer, if the first section of the proposed multi-circuit 66/22kV construction is established over the 21 kilometre route between Benalla and Violet Town and the two circuits are operated in parallel at 22 kV in conjunction with augmentation of the two line voltage regulators.

This work was been scoped in some detail and direct costs were estimated to be [C.I.C] .

Option 3: Temporary diesel power station

An alternative solution to this capacity constraint would be the installation of a new temporary power station at Euroa to support the 22kV network and to address the capacity risk at times of peak demand.

AusNet Services initiated this solution by utilising hire generation to secure the feeder during the summer of 2009/10 and beyond. The cost of installing this temporary generation for 4 months each summer is summarised in the following Table.

C.I.C

Option 4: Permanent gas fired power station

Another alternative is establishment of a permanent gas fired power station using up to 4 X 1.1 MW natural gas-fired engines. Transmission pressure gas is available in the Euroa Township but a gas city-gate would need to be established for a power station. The costs for setting up a permanent generation facility would be [C.I.C] including the gas city-gate, site establishment and connection of generators to the electricity distribution network. The capacity of such a power station can be progressively increased in a similar manner to that of the temporary diesel powered installation. The annual running, operating and maintenance costs are slightly cheaper than those for a diesel installation around [C.I.C] per annum rising to [C.I.C] per annum by summer 2015/16.

4.3.3 Losses

Amongst other obligations; Clause 3.1 of the Electricity Distribution Code requires a distributor to take into account distribution losses in a way which minimises costs to customers when developing and implementing plans for its distribution system assets.

Planning studies show that losses of 1.4MW on the feeder backbone between Benalla and Violet Town can be reduced to 0.35MW with the proposed 22 kV operation of the multi-circuit configuration. A saving of 1.05 MW at peak demand provides annual savings of 3,700 MWhr worth [C.I.C] rising to [C.I.C] as shown in the following figure.

C.I.C

Loss reductions associated with embedded generation or demand reduction options are less significant ([C.I.C] over the same period above) as the reduction only occurs during the relatively brief period when the embedded generator or demand management is contracted

4.3.4 Hypothetical Economic assessment

The selection of an economic option at Euroa is heavily dependent on the accounting of line losses.

The cost of capital for the network option is [C.I.C] per annum based on a cost [C.I.C] and a cost of capital at 7.5% per annum. This is offset by the rising value of losses to the extent that the network option becomes economic in the summer of 2013-14 as illustrated in the following figure.

C.I.C

The recommended option is to use temporary generation in conjunction with demand side response until and through the summer of 2013/14 and then augment the network capacity at an estimated cost of [C.I.C] (direct) prior to the summer of 2014/15. AusNet Services' 2011–2015 EDPR submission contained both non-network and network augmentation moneys to outwork this recommendation.

4.3.5 Recent developments

In 2013 AusNet Services procured a fleet of 4 x 1MW diesel gen sets that can be deployed to provide summer peak network support. During the summer of 2013/14, 2 of these 1 MW gen sets were installed at the Euroa showgrounds to provide support to BN1 instead of hiring generators from a third party.

4.4 BN1 C&I demand management trial

The BN1 22 kV feeder supplies 4,380 customers in Violet Town, Euroa and surrounding areas. It is AusNet Services' longest feeder with 1,160 kilometres of predominantly overhead line with a 47 kilometre long backbone from Benalla to Euroa.

In recent years a range of network initiatives were utilised to manage peak summer demand. These included the installation of pole mounted capacitors and increasing conductor clearances. As a result the maximum summer demand asset rating on the BN1 feeder was significantly increased. However, even with these increased ratings a number of outages were experienced during summer 2009.

To ensure continuity of supply during periods of summer peak demand, around 2MW of temporary generation has been installed at the Euroa Showgrounds. This has proven to be an effective method of avoiding outages, albeit expensive at around [C.I.C] per annum. This expense was also incurred irrespective of requirement to dispatch the generation.

With a view to testing the viability of customer side demand management as an effective solution to this problem, a trial was conducted over the 2012/13 summer period. Following an exhaustive scan of C&I customers who contributed to the peak demand, a poultry farmer was contracted on a Network Support Agreement. The customer had an N-1 capability through installed temporary generation. Under this non-binding agreement, the customer was paid an annual reserve fee for participation in the program of around [C.I.C] and a performance based demand reduction fee of around [C.I.C].

Over the 2012/13 summer period the poultry farmer was notified by the CEOT of 5 network events each spanning 6 hours. The customer responded by initiating installed temporary generation to isolate remove any reliance on the distribution network. As a result the customer's response to each network event was 100%. On average this response was around 320kW.

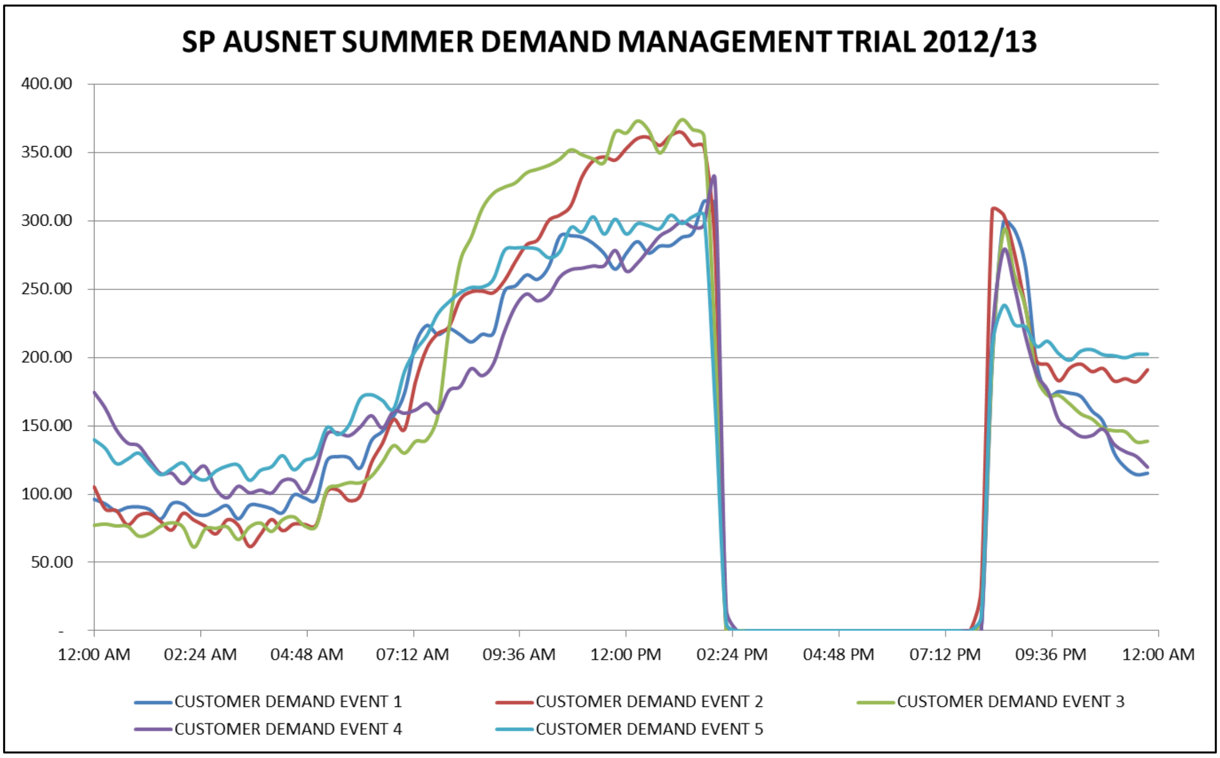

Figure 10 - Poultry farm response to Network Events

Post-summer review of the program was positive from both the CEOT and the customer.

4.5 Grid Energy Storage System (GESS) Trial

Under a specific provision in the EDPR that provides funding for demand management innovation, in 2014 AusNet Services installed a 1 MW / 1 MWh battery storage unit with a smart inverter and 1 MW diesel support generator connected at 22 kV feeder level in Watsonia. The diesel generator was included in order to keep overall cost of the entire system down, but to fully simulate a larger battery system.

The GESS was used over subsequent summer periods to provide:

- Network peak demand management
- Voltage support, power-factor correction, islanding and other power system functions by intelligent inverter control

The contract for design and construction was awarded in 2013 and commissioned during 2014. The trial provided operational data to verify performance of the battery, inverter and the controller in supporting the grid for peak demand, voltage and power factor. During the 2 year trial the system tested the functions of:

- Managing peak demand to delay the capital expenditure for augmentation of a 22 kV distribution line, until a clear demand growth trend emerges.
- Mitigating value of customer reliability (VCR) risks until augmentation is justifiable.
- Reduce overall OPEX expenditure on rental of mobile generation specifically to reduce summer demand.
- Improve business reputation, as fewer and shorter interruptions and voltage sags will be experienced by customers.
- Opportunity to gain knowledge and experience in MW-size GESS for network support

4.5.1 Cost summary

Except for niche applications, battery storage is not yet economic to deploy in place of generation or network solutions, however the technology is on a declining cost curve. The GESS business case presents costs at the time of commissioning as well as a forecast for 2018.

The table below shows estimated indicative pricing for the components of the system using average budgetary prices from the more proven submissions:

Battery System (1MWh)	[C.I.C]
Battery Inverter	
Transformer & Switchgear & Control	
Diesel Generator	
Project Engineering & Site Costs	
Supplier Contract Total	

Table 2 - Indicative cost breakdown of GESS components (2013).

4.6 Residential Battery Storage trial (Installed 2013)

The Residential Battery Storage Trial aims to deploy energy storage systems comprising a 6.6kWh battery smart inverter and solar PV generation into domestic dwellings to:

1. Determine whether battery storage can be used to reduce residential peak demand.
2. Determine whether self-consumption of solar PV generation can be used to manage network voltage rise issues.
3. Determine the economic viability of residential battery storage as a means to manage peak demand and thereby defer asset investment.

The trial will deploy ten systems to AusNet Services employees and trialled over a period of two years. The bulk of systems were installed prior to the 203/14 summer peak period.

The residential battery storage system consists of an energy management system that controls and measures the energy flows between the battery, solar PV and the household distribution board is shown in the following diagram. All areas of interest in the system will have metering points (indicated by 'M' in the diagram) for data capture and monitoring. The system can operate automatically or controlled by AusNet Services via the remote control feature.

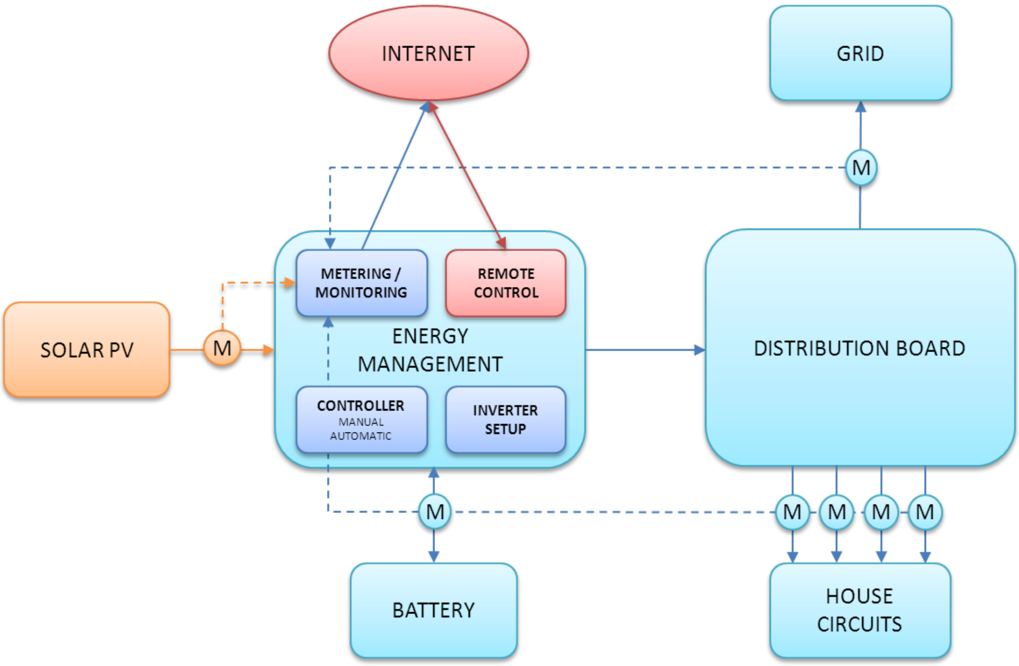

Figure 11 – Schematic diagram of a residential battery storage system

As at January 2014, initial results just after system installation are promising. The high resolution data capturing capabilities of the system are already providing new insights into how energy flows at the household level. The graph below shows the profile of one of the trialists over a period of one day. It shows the energy consumed, the energy generated (solar PV) and how the battery is utilised to limit the peak demand. We can now zoom into this graph down to each individual second of the day to analyse exactly how the battery interacts with the household. This data will be utilized to develop future business strategies for residential battery solutions.

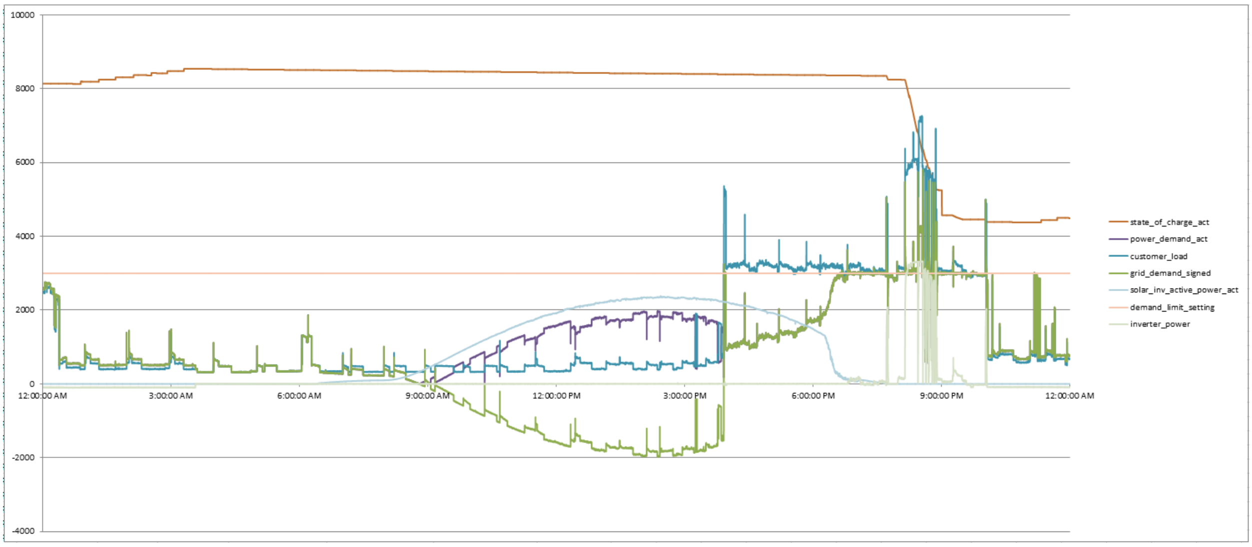

Figure 12 - Sample 1-second data from the Residential Battery Storage trial

The residential battery trial is fully funded by the AER’s Demand Management Innovation Allowance. Capital costs are relatively high and would not currently be economic for network support. The high capital costs are due to a combination of the extra system functionality required for the trial, the high quality of components used and the currently high costs of battery storage in general. In commercial application, each of these components would be expected to reduce.

4.6.1 Cost summary

The installed capital cost of the battery & inverter systems in the residential storage trial was approximately [C.I.C] per unit, rated at 6.6kWh and 3kW peak output. The 6.6kWh rating is equivalent to provision of 1.7kW of network support across a 4 hour peak period.

Cost information obtained through the tender process and through market monitoring is summarised below.

	Supplier 1	Supplier 2	Supplier 3	Supplier 4
Chemistry	Lithium	Lead acid	Lead acid	Lithium
Capacity (kWh)	6.6	9.6	9.6	20
Power (kW)	3	4	3	5
Cost	[C.I.C]			
Unit cost $/kWh				
Unit cost $/kW				

Table 3 - Residential battery storage system quotes

4.7 Short term demand forecasting trial

Short-term load forecasting can play an important role in optimising deployment and dispatch of demand management options. The challenge for this project was set to identify peak feeder demand 3 days ahead which would give time for dispatch and connection of generation in a more efficient targeted way.

The trial was performed over summer 2012/13. The effectiveness of the feeder/zone substation level models for predicting peak load (Amps or MW) on 3 selected feeders was assessed using weather forecast data, up to 3 days ahead.

In the first stage of the project, a number of models were developed for each feeder. Development of the models was accomplished prior to the start of the 2012-13 summer to ensure that all models were unbiased towards test data which was collected during that summer. Performances of the models were monitored during the trial period. Results of the trial were then analysed in details and sources of errors in forecasts were investigated.

Results showed that the models performed differently. Generally, an acceptable hit rate[11] was achieved however some of the models resulted in a high number of false positives[12]. A simplified cost and benefit model was developed to assess and rank the models based on their economic performance.

A number of outcomes and conclusions came out of this trial, including

- Reliability assessment of BOM temperature forecast
- Importance of the use of local weather observation/forecasts for modelling
- Identification of best predictors for load forecasting
- Development of short term load forecasting models and identifications of best modelling methodologies

A second trial was carried out for 2013-14 summer aiming to Investigate potential improvements in short term peak demand forecast accuracy using granular temperature forecast data. Hourly temperature forecast data provided by [C.I.C] was used in this trial.

Modelling, data preparation, analysis, and assessments were completed internally. The only procurement cost of the trials was [C.I.C] for weather forecast data provided by [C.I.C] for specified locations.

[11] Correct forecast of high peak demand days

[12] Low peak demand days forecasted as high peak demand

4.8 Mooroolbark Community Minigrid Trial

To test a range of future non-network solutions, AusNet Services successfully built a suburban community mini-grid in Mooroolbark utilising Demand Management Innovation Allowance (DMIA) funding. The project comprises:

- 18 homes, 14 of which have solar and battery systems,
- central network devices including a battery-based mini grid stabiliser and an LV switching cabinet,
- a cloud-based monitoring and control system (third party), and
- a second cloud-based network optimisation platform (in-house) which orchestrates the distributed electricity resources to manage network power flows.

The trial aims to quantify the various benefits of clustered distributed energy resources for both the community and distribution network, help AusNet Services understand the technical challenges and opportunities associated with integration of solar PV and mini-grids to the network, and test a model for actively engaging with distributed energy resource customers into the future.

The trial has recently concluded, and tests have proven the capability of customer battery solar and storage to be able to provide demand management support, both locally, and to the upstream network, as well as providing reliability support through islanded operation of the mini grid. AusNet Services has actively promoted the project and key milestones to date via various media reports and conference presentations.

4.8.1 Cost summary

The cost information below is based on the initial EOI submitted by [C.I.C]

C.I.C

C.I.C

4.9 Networks Renewed Trial

AusNet Services joined the University of Technology Sydney in an ARENA funded project called Networks Renewed. This project aims to test the ability of modern smart solar and battery inverters to provide reactive power support to the network to help manage supply voltage levels. The project was implemented on a SWER system in Yackandandah where solar uptake is high and voltage issues were experienced.

Initial testing proved the ability of the solar and battery inverters to improve supply voltages by around 3-5 V, and further testing was conducted across 2018-19 summer to develop and test improved control methods. Preliminary results were presented at a public forum held in Melbourne to coincide with the All Energy conference.

C.I.C

The project utilised a local controller called the [C.I.C] to manage the solar and battery systems. The [C.I.C] then established a communications link with the AusNet Services DENOP (Distributed Energy Network Optimisation Platform).

4.9.1 Cost summary

The cost information below was composed from the average offering during the community briefing in Yackandandah on February 2018:

Battery System (10kWh)	[C.I.C]
Battery Inverter (5kVA)	
[C.I.C]	
Solar System (panels 4-5kW & inverter 5kVA)	
Install	
Supplier Contract Total	

5 Appendix 2 – References

Demand Side Engagement Strategy

http://www.ausnetservices.com.au/assets/demand_side_engagement_strategy/Demand%20Side%20Engagement%20Strategy%2029August2013%20(1).pdf

Distribution Annual Planning Report

http://www.ausnetservices.com.au/assets/procedures/DAPReport.pdf

Distributed Energy Resources – Integration Strategy

Internal strategy document, available from the Distributed Energy & Innovation team.