16 May 2012

Commissioners
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Via electronic lodgement: www.aemc.gov.au

Dear Commissioners

Power of Choice – giving consumers options in the way they use electricity

Thank you for the opportunity to respond to the AEMC's Directions Paper for the Power of Choice Review.

Please find attached the ENA submission.

ENA supports the key themes identified by the AEMC, in particular the role that networks can play in promoting DSP outcomes. We welcome AEMC's further consideration of network issues, in particular the profit incentives to undertake DSP.

ENA welcomes the opportunity to contribute to the review and found the recent meeting with AEMC staff very constructive. Should we be able to assist in any further way please contact Tanya Barden on 02 6272 1514.

Yours sincerely

M Roberts

Malcolm Roberts
Chief Executive

ENA submission—AEMC Power of Choice Directions Paper

16 May 2012

Energy Networks Association Limited

Level 3, 40 Blackall Street
BARTON ACT 2600
Telephone: +61 2 6272 1555
Fax: + 61 2 6272 1566
Email: info@ena.asn.au
Web: www.ena.asn.au

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1. Summary

ENA believes network businesses can relieve some of the longer-term pressure on electricity prices by providing consumers with options to manage their electricity use. Such demand side participation (DSP) can help consumers cut costs by reducing discretionary energy use at times of peak demand. Reducing peak demand also allows network businesses to make more efficient use of existing infrastructure and defer the need for costly expansions of network capacity.

However, the opportunities for network businesses to undertake DSP are constrained by a lack of strong commercial incentives. Like any business, networks need to be able to fund and receive an appropriate return for their investment. Government attention has focused on imposing regulatory obligations to advance DSP; ENA believes that incentives will work far more effectively.

ENA welcomes the AEMC's further investigation of the incentives for networks to undertake DSP. As an input to this process, ENA has identified regulatory reforms that will strengthen the commercial incentives for networks to undertake DSP, by allowing them to share in the longer-term and broader value chain benefits of DSP. In addition, ENA recommends minor regulatory enhancements, for example to balance the incentives between investments in operating and capital expenditure.

To further support the role that network businesses can play in the delivery of DSP, ENA also recommends that the rules be clarified to ensure that distributors and other parties can provide energy consumption information to consumers, provided that security and privacy of data is appropriately managed.

In addition to undertaking DSP activities either directly or in partnership with other parties, networks can play an important role in enabling retailers and third parties to provide DSP offerings. For example, as the owners of monopoly network infrastructure, including small customer metering, network businesses can provide facilitated access to DSP products, such as direct load control of large residential appliances. However, there are also other emerging non-meter based technologies that retailers and third parties can use to provide a range of energy management options.

As energy management is enabled by new technologies, the movement of significant amounts of energy into and out of the networks has the potential to destabilise electricity supply and power quality, with significant potential impacts on customers at local levels. It is therefore important to preserve the integrity, reliability and security of the network, while allowing distributors, retailers and third parties to undertake energy management initiatives. To achieve this aim it is vital that all parties wishing to undertake energy management comply with certain protocols. ENA has commenced consultation on two draft protocols.

In the absence of a mandate for smart or interval meters, several network businesses have commenced a new and replacement program for interval meters that can be later upgraded with two-way communications capabilities. Networks are also conducting trials to inform their business case for a commercial deployment of interval or smart meters, as well as investigating other non-meter based options for energy management. The ENA's recommended demand management incentive scheme will assist in building the case for investment in enabling technologies, by overcoming the split benefits problem.

Given the relatively immature nature of many of the new technologies, and the market for related DSP offerings, ENA considers that the supporting market and regulatory frameworks that enable consumer choice need to be flexible to adapt to a changing environment and to respond to learnings from pilots and trials. Ultimately, costs to consumers are likely to be minimised, and benefits maximised where DSP can be delivered cooperatively with other parties. Networks welcome such an approach.

2. Introduction

The Energy Networks Association (ENA) is the peak national body for Australia's energy networks, which provide the vital link between electricity and gas producers and consumers. ENA represents electricity transmission and distribution and gas distribution businesses on economic, technical and safety regulation and national energy policy issues.

3. Importance of DSP for consumers and networks

Electricity networks are built to meet maximum (peak) annual demand and government mandated reliability standards. For some years, peak demand has been growing more rapidly than aggregate demand. In some areas, peak demand is considerably higher than average demand, which means a substantial amount of network infrastructure is only used for a few short periods each year. The cost of building this capacity has to be recovered, increasing the average cost of electricity.

The underlying causes of peak demand growth vary by region across Australia but in general are a function of:

- changes in the type and size of dwellings,
- penetration of air-conditioning (heat and cooling) in residential and SME premises,
- installed capacity of air-conditioning per premise,
- growth in usage of other electrical appliances, and
- growth in population and economic activity (either directly or indirectly).

These factors all contribute to peakier demand profiles.

Network businesses are sensitive to the rising costs to consumers of simply building more assets to match peak demand growth. If growth in peak demand can be curbed through demand side participation (DSP), more efficient use can be made of existing infrastructure and new, costly investments can be deferred. Over the long-term, this would relieve some of the pressure on retail prices. DSP is also an important network management tool for achieving reliability and power quality standards.

For individual consumers, DSP can offer options to manage energy use and costs. Together, information and energy management products can enable consumers to make decisions that reflect the value they place on using electricity at peak times and the benefits of changes in their consumption patterns.

4. Networks' role in DSP

Network businesses perform two roles in relation to DSP:

1. Directly undertaking network-initiated DSP, where these activities improve the efficiency of regulated network operations and investments, and

2. Facilitating the delivery of DSP by other parties, such as retailers and aggregators.

4.1 Network-initiated DSP

In order for DSP to be a viable alternative to traditional network investments it needs to be predictable and reliable in its delivery, that is, network planners need to know with certainty how much peak demand reduction will occur, in what areas, and at what times. Network businesses also need to be able to select DSP options that are cost-effective, efficient options that best suit the circumstances of their network, business model, consumers and any jurisdictional requirements.

While innovative network and retail tariffs are an important mechanism for engaging consumers and stimulating a demand response, they are not a silver bullet. For DSP to be effective a range of measures are required, including options that enable consumers to "set and forget" their financial and comfort preferences.

Network businesses require flexibility to increase the range of options for consumers, such as developing innovative tariff-based options, as well as non- tariff based contractual arrangements.

The non-tariff based DSP activities that networks may engage in can be categorised as:

1. Local measures aimed at relieving a specific network constraint at a particular location or time

    a. for example, contracting with commercial and industrial customers and embedded generators in a particular area for network support; or offering residential consumers in particular suburbs an incentive to participate in a direct load control program for major appliances, such as pool pumps and air conditioners

2. Broad-based measures aimed at reducing demand across the network and deferring demand driven capital expenditure across all assets in the medium to longer-term

    a. for example, deploying interval meters, consumer education and engagement programs, and other DSP projects that deliver benefits beyond the network boundary and/ or beyond the current regulatory period.

Whilst local DSP activities can be effective, networks are investigating how they can improve asset utilisation everywhere all the time – not just in constrained areas. There is also a need for broad-based engagement campaigns to raise awareness about the impact of current consumption patterns on network costs and what consumers can do to reduce the upward pressure on network investment. Such campaigns that increase the general level of awareness and engagement will increase the ease and effectiveness of pursuing targeted, specific actions in particular areas requiring network support (such as voltage regulation), facing a constraint or pressing need for augmentation.

While the need for such supplementary measures may decrease over time as consumers adjust to more efficient price signals and their responses become more predictable, it is likely that there will remain a need for network-initiated DSP activities that target specific areas. Network businesses are keen to explore opportunities for network businesses and others to work together to deliver solutions that minimise overall costs and increase the benefits for consumers.

Case studies

Network businesses have traditionally undertaken or contracted local DSP to defer network capital expenditure and reduce the risk of not being able to supply consumers. Electricity network businesses have also used limited broad-based DSP, such as off-peak hot water, as one of their tools to balance the supply and demand on their network or for network support, such as voltage control. This capability has developed over a long time and was not specifically justified on the basis of an immediate constraint on the network, but on the longer-term ability to influence and manage the load curve.

As the following case studies indicate, network businesses are exploring various approaches to network-initiated DSP. In some instances, networks are engaging directly with residential, commercial and industrial consumers for the provision of DSP (eg through rebates to install energy management devices for load control, or large customer load curtailment contracts); and in others they are working in partnership with other DSP providers (eg to develop network support arrangements with large customers).

In the summer of 2009/2010, NSW distributor **Ausgrid** launched a local project to cut demand by 6.3 MVA at Willoughby sub-transmission substation in order to defer building a new substation and ensure reliable supply to local customers. The target reduction was achieved through a mix of network support agreements with large customers and a gas-fired cogeneration site (through an aggregator), and the installation of power factor correction equipment. The project benefited customers through capital expenditure deferral savings and a 58% reduction in the risk of non-supply.

Ergon Energy has a local DSP project underway in **Moronbah, Queensland** which is aimed at reducing demand by 3 MVA and deferring the need for a new substation and transformers until the end of 2014, and a new 11kV feeder until 2016. Ergon has forecast that, in the absence of this project, demand on the existing substation would exceed its capacity by summer 2012/13. Ergon would not have been able to complete a network solution by this time, hence the use of DSP allows Ergon to maintain a reliable supply.

South Australian distributor **ETSA** is undertaking a trial of demand response enabling devices (DREDs) in air conditioners with the aim of quantifying the potential demand reduction benefits that such measures could deliver. Customers will be given an incentive payment in return for giving ETSA authority to limit the power consumption of their air-conditioners at certain times during the summer.

Queensland distributor **Energex** is running broad-based demand management trials with the aim of reducing forecast demand across its network by 144 MVA by 2015. These trials include:

- offering residential consumers an incentive payment in return for installing an energy management device in pool pumps, air conditioners and hot water units, which allows Energex to limit their peak power consumption during critical times.
- offering commercial and industrial consumers an incentive payment in return for installing energy management solutions such as power factor correction equipment, and upgrades to lighting, heating, ventilation and cooling systems.
- reward based tariffs that encourage customers to reduce their energy consumption during peak periods.

In summer 2011, **Victorian** distributor **SP AusNet** undertook a broad-based DSP project, by restructuring its commercial and industrial network tariffs to better reflect the network's costs and target reductions in demand during peak times on critical peak days. This was achieved by introducing a two part charge with a critical peak component (based on the customer's maximum demand on five notified days during a defined critical peak demand period); and a capacity component. The critical peak demand tariff resulted in a significant customer response, with a reduction of 88MW in summer peak demand.

Western Power has successfully engaged residential consumers through the Perth Solar Cities (PSC) residential energy efficiency program, which trials air-conditioner load control using smart meters and home area network communications. Western Power also participates in the Future Energy Alliance with a local retailer to deliver the energy efficiency campaign Switch the Future.

Incentives for network-initiated DSP

As the case studies indicate, networks are actively involved in DSP activities for residential, commercial and industrial customers. However, these programs tend to be trials or small scale, local initiatives.

Networks have no commercial incentive to go beyond these types of activities to a greater uptake of broad-based DSP activities that deliver wider supply chain and/ or longer-term benefits. This is largely because networks can only recover the costs of broad-based DSP projects they do not have a profit incentive to actively pursue such projects.[1]

As a result, DSP activities that deliver a benefit beyond the network boundary, but insufficient current period network benefit (deferring capital expenditure or maintaining reliability), are not proceeding because they do not have a positive business case when considered only from the network benefits perspective. The regulatory obligations only achieve the minimum acceptable DSP response from network companies whereas a positive incentive should achieve a greater DSP response, closer to what is economically efficient for the whole electricity supply chain.

To encourage broad-based DSP, network businesses need to receive a return on these activities at least equivalent to investing in traditional network infrastructure. ENA has identified regulatory reforms to strengthen the commercial incentives for networks to undertake additional, efficient DSP activities. This will drive a better outcome than regulatory obligations.

Firstly, the ENA recommends minor regulatory enhancements that can:

- balance the incentives between capital and operating expenditure,
- balance the incentives to undertake DSP within rather than at the beginning of a regulatory period, and
- ensure consistency in the arrangements for transmission and distribution businesses.

Attachment 1 explains these recommended rule and AER practice changes, which will provide solutions to some of the issues raised by the AEMC in its Supplementary Paper *Profit Incentives for Distribution Network Businesses and Demand Side Participation*. While these recommendations remove perverse incentives with respect to investment choices between operating and capital expenditure[2], they do not provide the necessary positive incentive to undertake DSP.

Secondly, to provide a positive profit incentive for network businesses to actively pursue DSP, ENA recommends that the AER apply a new demand management incentive and embedded generation connection scheme (DMIEGCS, previously the DMIS). An effective incentive mechanism would allow network businesses to share a portion of the benefits (reduced costs) that network businesses create at other levels of the supply chain; and the longer term benefits of the DSP initiative to offset the upfront costs. It would also offset any negative revenue impact in price capped jurisdictions. As explained in Attachment 2, this requires only minor rule changes, but more fundamental changes to the AER's practice. ENA has proposed principles and preferred elements for a revised incentive scheme, for discussion with the AER and the AEMC.

ENA members have indicated that if an effective incentive scheme was in place they would be able to significantly boost their capability through pilots and trials and beyond, develop better analytical tools to assess non-network options, undertake additional engagement with end-users and potential DSP providers, including providing better information on DSP opportunities. This capability building is an important factor in shifting from innovation trials to the deployment of larger scale DSP programs.

Together, these changes will, over time, reduce the investment needed in traditional network infrastructure, delivering benefits to end-users.

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[1] While Energex was successful in gaining AER funding for demand management initiatives on the basis of the full supply chain (including generation and transmission) benefits, the funding provided was based on cost-recovery only. Energex did not receive any additional incentive payment that reflected a share of these benefits.

[2] ENA has raised these issues more generally in its submission to the AEMC's assessment of the *Economic Regulation of Network Service Providers* rule changes.

Ring-fencing

Electricity network businesses support the National Competition Policy reforms, which promote a framework under which activities that are able to be performed by a competitive market should be separated from a natural monopoly. Currently, where network businesses undertake activities that are performed by a competitive market, they do so through a separately ring-fenced entity.

This prevents monopoly network businesses from giving priority access, information or cheaper prices to any competitive operations that it has (if any). One key aspect of ring-fencing is to ensure that the revenues earned from a competitive activity are not cross-subsidised from regulated activities.

Network businesses generally undertake DSP as an intrinsic part of their regulated network services. They do not generally earn direct revenue from offering DSP to consumers – these services will generally be an expense to the business, aimed at reducing longer term network costs and improving network operations. There is no need for such network-initiated DSP activities, which are part of standard control services, to be undertaken through a separately ring-fenced entity. Indeed, doing so would undermine the reasons and efficiencies of the network business undertaking DSP as part of their delivery of monopoly network services.

Where distribution network businesses have an affiliated retail business, it is understandable that there could be concerns regarding the preferential treatment that distributors could potentially give to their affiliated retail business (for example, preferential access to load control or access to information regarding network constraints). These concerns are already addressed through regulatory mechanisms that require structural separation of these related entities.

4.2 Network-facilitated DSP

Retailers and third parties face different drivers to network businesses, and hence it is anticipated that they will seek to offer DSP options (such as energy management services) to meet their own commercial objectives (such as to minimise exposure to wholesale market risks) as well as the objectives of consumers (minimise price of energy consumed). Where network businesses offer DSP direct to consumers as part of a network service, this does not/ would not preclude retailers or third parties from offering DSP as part of a retail energy market offering. Indeed, given the generally localised nature of network offerings, and the generally broader nature of retail and third party offerings, these energy management services may be complementary to, rather than substitutes for, one another.

As set out in ENA's *Smart Meter Operating* Model (Attachment 3), there are various options by which retailers and third parties may choose to offer energy management services to small customers. Some of these options utilise smart metering infrastructure (SMI – half hourly interval meter with two-way communications), while others do not require SMI for demand management but may rely on manually read interval meters for billing and settlement purposes.

The following section sets out the access framework by which network businesses can play a role in enabling the provision of DSP by other parties.

Access framework

As the provider of essential monopoly network infrastructure, including small customer metering, network businesses currently provide access to the services enabled by this infrastructure, in order to facilitate competition in the retail energy market. Network businesses do this by providing a network service that enables retailers to transmit their energy purchases from generators to customers. In the case of small customers, distributors also provide metering services that allow retailers to measure energy sales at the consumer's premise.

As set out in the *ENA Smart Meter Operating Model*, the move from accumulation and interval metering to smart metering infrastructure potentially expands the range of services enabled by monopoly network infrastructure. For instance, smart metering infrastructure introduces the potential for network infrastructure to enable direct load control and supply capacity control, which can be used as a point of differentiation between market participants and hence can facilitate competition in retail energy markets.

Networks can provide retailers and third parties with facilitated access to these and other energy management services enabled by smart meters, so that these parties can offer energy management services to customers as part of their retail energy market offering.

However, such services have the potential to interfere with the safety and reliability of the electricity network, hence it is vital that retailers and third parties wanting to undertake energy management comply with *Load Management and Network Security Protocols*, and the distribution business's own rules for acceptable levels, frequency and duration of load switching. In addition, the connection of retail and third party devices to undertake energy management (such as a consumer, retailer or third party HAN) introduces risks to the security of consumers' metering information. Parties seeking to connect such equipment to a smart meter must comply with *Communications and Data Security Protocols*. ENA has developed draft protocols for consultation with industry, consumers and government (Attachment 4 and Attachment 5).

These requirements are consistent with the *Competition and Consumer Act 2010* (CCA), which safeguards the legitimate interests of infrastructure owners. Network businesses' legitimate interest is in maintaining the security and reliability of network services, hence the provision of access is subject to the caveat that network security and reliability are paramount and must be maintained.

4.3 Consumer relationships

ENA considers that distributors, retailers and third party energy service providers should all have the ability to provide information and energy management services to consumers.

This approach is consistent with the National Energy Customer Framework, which enshrines a triangular relationship between the customer, network business and retailer business, and makes it clear that distribution businesses have a relationship with customers for the purpose of providing network services.

The reason network businesses need to undertake energy management directly is to achieve the requisite demand response to justify deferral of a network augmentation project. While network businesses may seek out the expertise of retailers and third parties to offer DSP to consumers, there may be situations in which network businesses need to offer such services directly to consumers. Retailers do not have the same drivers (eg cost and time) and incentive to undertake DSP that the network needs to be implemented by the due date to avoid an augmentation. As a result, retailers or third parties may not be interested in targeting particular geographic area with an energy management product that meets the distributor's needs; or they may be unable to deliver the requisite level of DSP response. Under the rules, network businesses carry the risk associated with delivering certain standards of network services. Therefore it is reasonable that network businesses will either build networks or alternatively deliver more DSP themselves to mitigate this risk of insufficient DSP being delivered by the market.

With respect to the provision of information, the rules governing the provision of data are currently subject to interpretation and some uncertainty compared to other regulations (National Energy Customer Framework and some state legislation), which require distributors to provide information about customers' energy consumption. There would be benefit in clarifying the rules to ensure minimum data provision by an obligated party, with the ability for other parties to deliver other models of data provision provided that security and privacy of data is appropriately managed.

5. Technology

5.1 Smart meters and interval meters

Manually read interval meters and smart meters enable network and retail businesses to set efficient, dynamic prices, such as time of use or critical peak prices, and enable consumers to be billed according to their actual consumption rather than an average load profile. Together these capabilities give consumers the potential to benefit from reducing their consumption at peak times. Smart meters can also enable the connection of in-home displays and internet portals that provide consumers with near real-time information about their energy usage, pricing and bills.

Smart meters can also enable consumers to participate in other types of DSP, such as agreeing to participate in a load control program for residential air conditioning and pool pumps in return for an incentive payment. It is however, possible to undertake load control programs without smart metering, for example, through communication with demand response enabling devices (DREDs) or time switches.

In the absence of a mandate for either interval or smart meters, distribution businesses are conducting pilots and trials to inform their business case for a commercial deployment. Several distribution businesses have also adopted a policy of installing upgradeable interval meters instead of traditional accumulation meters for new connections or to replace aged assets. These interval meters can be later upgraded to smart meters, when there is a positive business case.

One of the main challenges to a wide spread commercial deployment of interval or smart meters has been the split benefits problem – network businesses may not receive sufficient benefits from an interval or smart meter deployment to justify investment, even though such investments may have a net benefit for the community as a whole.[3] ENA's recommendations to revise the AER's DMIEGCS seek to overcome this split benefits problem, by enabling networks to share some of the broader value chain benefits.

Some of the other challenges to a wide-spread commercial deployment of interval and smart metering technology include:

- the technology, processes and systems for smart meters are still maturing,
- network concerns about potential asset stranding and risks to revenue recovery should a "contestable' interval or smart meter be installed alongside a network meter, and
- the need for clarification in the rules regarding the role of network businesses as the Responsible Person for small customer metering, regardless of whether the meters are manually or remotely read (see following section).

In the Directions Paper, the AEMC has raised the question of whether and how consumers can be given a choice in the type of meter installed at their premise. While network businesses generally support customer choice in terms of DSP options, it is important to consider the costs of enabling such choices. For instance, giving customers the choice of whether to have a smart, interval or accumulation meter would require significant additional costs that would need to be recovered. These included the costs of maintaining multiple meter data systems and the additional costs associated with installing meters on request instead of deploying them in a planned and more economically efficient manner, area by area.

5.2 Meter contestability

The status quo in the NER is that small customer (<160 MWh) metering is not contestable. This arrangement was put in place because governments considered that the benefits from economies of scale in exclusive provision of small customer metering outweighed the potential benefits of contestability. A change in metering technology from manual to remote collection of data does not alter the fundamental reason why small customer metering is currently not contestable.

[3] The difficulty in justifying network investment in interval or smart meters is not as great in situations where the existing meter stock is at end of life and due for replacement.

Consistent with this is the Victorian Government's decision to mandate distributors' exclusivity in the roll-out smart meters. This decision did "…not depend on metering installation type but volume consumption".[4]

To maintain consistency with the original policy intent of the NER, there is a need for a minor change to the rules to facilitate network businesses deploying smart metering technology, where they have a business case. This requires a minor rule change to the appropriate meter type to clarify that remotely read interval meters (smart meters) for small customers are a monopoly function of network businesses.

Some parties have argued for a change to the existing exclusive metering provision arrangements for small customers. However, as agreed by the National Stakeholder Steering Committee for the National Smart Meter Program, there must be a gateway review of the costs, benefits and practicalities of contestability before deciding whether to proceed. Such a review would also need to give consideration to the fact that smart meters are not the only means for providing energy management services; and smart meters play important network and metrology functions, which could be compromised by contestable infrastructure provision.

[4] The draft National Electricity Amendment (Ministerial Smart Meter Roll Out Determination) Transitional Rule 2009 http://share.nemmco.com.au/smartmetering/Document%20library/Work%20Stream%20documentation/RWG/Meeting%2013%20-%2010-11%20Mar%2010/RWG%20workshop%2013%20-%20Smart%20Meter%20Metering%20Installation%20Type%20v0.3.pdf

6. Efficient price signals

ENA strongly supports a transition towards network prices that reflect underlying cost drivers and enable consumers to make informed and efficient consumption decisions. However, the nature of the electricity network sector is such that it may be impractical and too complex to develop prices that completely reflect the cost of the network elements used to serve individual consumers in different locations and at different times of the day. In addition, retailers and governments have been reluctant to introduce sufficiently cost-reflective prices.

The goal of policy makers should therefore be to **allow the market to determine the appropriate level of cost reflectivity and complexity in network tariffs** that consumers will accept and respond to. This may involve a gradual move away from current tariff structures that are predominantly based on a flat consumption rate (c/ kWh) towards network tariffs that reflect capacity and time of use cost drivers, which could be certain times of the day, week or season. It may also involve the payment of incentives or rebates to consumers in return for agreeing to have their consumption reduced at peak times. Such payments can provide consumers with a price signal and hence may be considered as a proxy for a cost reflective network price.

Some network businesses have increased the cost reflectivity in their tariffs. These include transmission network tariffs, distribution tariffs for some commercial and industrial customers, and a limited application of seasonal or time of day tariffs for residential consumers. These tariffs have delivered benefits for consumers without a negative impact on those that are socio-economically disadvantaged. This is consistent with international studies that have found that, contrary to commonly held perceptions, dynamic pricing structures may have the effect of reducing the bills of low-income consumers even without them changing their energy consumption patterns.[5]

Even once suitable metering technology is in place, the transition to more flexible and efficient pricing will take some time as networks and the market determine the level of cost-reflectivity that is required to stimulate sufficient demand response; and the market and consumers adapt and respond to new network tariffs.

As already noted the move to more innovative pricing is important however it should not be seen as a 'silver bullet', particularly since it will take some time for a level of certainty (firmness) of consumer responses to emerge. For DSP to be effective, a range of supplementary non-tariff based options are also required.

[5] Lisa Wood and Ahmad Faruqui, *Dynamic pricing and low income customers*, Public Utilities Fortnightly, November 2010

Attachment 1: Minor regulatory enhancements to balance capital and operating incentives

ENA recommends the following minor regulatory enhancements to support network-initiated DSP by:

- balancing the incentives between capital and operating expenditure,
- balancing the incentives to undertake DSP within rather than at the beginning of a regulatory period, and
- ensuring consistency in the arrangements for transmission and distribution businesses.

1. Allow DNSPs' to recover on-going operating costs for network support in subsequent regulatory periods

Deficiency

The payments a network business makes for network support (for example, for embedded generation) include two elements – an availability payment, and a performance payment if the option is called on. There is uncertainty about whether network businesses will be able to recover payments under an on-going network support agreement (operating expenses) in future regulatory periods. This is because when the AER considers payments under an on-going network support agreement it considers those payments made in the previous period, whereas this may not be an accurate reflection of costs in subsequent periods because a network support option may not have been called upon in the initial period. This could be a potential barrier to entering into a network support agreement.

Solution

The National Electricity Rules (NER) have overcome this uncertainty for transmission businesses by requiring the AER to permit continued recovery of payments under an existing network support arrangement.[6] A cost pass-through of payments under an on-going network support agreement is permitted in the regulatory periods after the period when the initiative commenced.[7]

There is no such provision in the NER for DNSPs. To ensure consistency in the arrangements for transmission and distribution, ENA recommends that the rules be amended to contain similar provisions for DNSPs.

2. Apply an incentive scheme for capital expenditure

Deficiency

Many DSP initiatives will require network businesses to substitute operating expenditure for capital expenditure. Currently the NER contains higher powered incentives for operating expenditure than for capital expenditure, that is, networks have more of an incentive to reduce capital expenditure than operating expenditure. This would normally create a direct bias against DSP initiatives that entail operating expenditure (such as network support payments for embedded generators, or rebates for direct load control).

The AER has sought to align the incentive power of operating expenditure on DSP to that of network capital expenditure by excluding DSP measures from the EBSS for operating expenditure. The outcome, however, is that the benefit from substituting DSP for a network option falls over the regulatory period – that is, the incentive for a network business to be efficient with respect to capital expenditure falls over the regulatory period. As a result, network businesses have less incentive to reduce capital expenditure and increase operating expenditure (DSP) as the regulatory period progresses.

[6] NER, rule 6A.6.6(c1)
[7] NER, rule 6A.7.2

Solution

ENA recommends that the AER improve the power of capital expenditure incentives so that they are constant over the period and at the same power as the operating expenditure incentives. This can be achieved by using its existing power to apply an EBSS for DNSPs' capital expenditure.[8] To ensure consistency in the arrangements for transmission and distribution, ENA recommends the NER be amended to contain similar EBSS provisions for TNSPs' capital expenditure and that the AER similarly apply such a scheme.

This issue is addressed in the ENA's submission on the economic regulation rule changes before the AEMC.

3. Exclude depreciation from the incentive scheme for capital expenditure

Deficiency

The current inclusion of depreciation in the capital expenditure incentive arrangements creates a bias against DSP projects that have a large IT capital component, such as automatic demand response systems.

Currently, if a network business spends an additional $1 on capital, it will not commence earning a return on that capital until the next regulatory period and will only earn a return on the depreciated value from that time. Thus, the business will forgo the return and the depreciation amount for the remainder of the regulatory period in which it makes the investment. The loss attributable to including depreciation in the incentive scheme varies with the life of the asset – a long lived asset will depreciate by less over several years than an IT asset with a much shorter life. This in turn creates a bias against switching from building network assets to IT-heavy DSP initiatives.

While the NER currently allows the AER to exclude depreciation from the EBSS for DNSPs' capital expenditure, it has chosen not to do so. There is no such provision for TNSPs.

Solution

ENA recommends the AER remove depreciation from the capital incentive arrangements for TNSPs and DNSPs. To ensure consistency in the arrangements for transmission and distribution, ENA recommends the rules be amended to contain similar capital expenditure incentive provisions for TNSPs.

[8] NER, rule 6.5.8(b)

Attachment 2: Strengthening commercial incentives for network-initiated DSP

1. AER to apply a new Demand Management Incentive and Embedded Generation Connection Scheme (DMIEGCS)

Deficiency

While the AER's network determination of operating and capital expenditure is intended to be the primary source of funding for DSP expenditure, the effect of this assessment process is to at best provide cost recovery, rather than an incentive to pursue DSP.

There is a need for a supplementary source of funding that provides an incentive for networks to pursue further DSP, including broad-based activities.

The NER allows the AER to establish a DMIEGCS (previously called the DMIS) to provide incentives for DNSPs to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way, or to efficiently connect embedded generators.[9] There is no such provision for TNSPs.

DMIS schemes previously implemented by the AER have included a demand management innovation allowance (DMIA) and, in the case of NSW/ ACT, a forgone revenue component. That is, the DMIS has in effect been a scheme focussed on an allowance to conduct research and investigate innovative techniques for managing demand. The AER has carried forward the D-Factor incentive scheme that was developed by IPART for New South Wales distributors. While this was a more effective incentive scheme, it has suffered from being limited to a short-term focus and was very complex and cumbersome to use and administer.

The scheme as generally applied by the AER is not a true incentive scheme as network businesses do not receive a share of the broader and longer-term benefits that are created by DSP activities. As a result, DSP activities that do not deliver a current period network benefit (by deferring capital expenditure or maintaining reliability), are not proceeding because the network business is unable to make a positive business case when only network benefits are considered.

In addition, unforeseen DSP projects that arise with a five year regulatory period are unfunded and hence are unlikely to proceed unless the deferral value to the network outweighs the cost of the DSP initiative in the remainder of the regulatory period.

Solution

A well designed demand management incentive scheme can improve the financial incentives to undertake network-initiated DSP projects, particularly those broad-based activities that do not deliver a deferral benefit in the current regulatory period, and unplanned local projects that arise during a regulatory period.

ENA recommends the AER enhance the DMIEGCS to allow NSPs to capture a portion of the benefits of reducing costs in other parts of the supply chain, and the longer term benefits of DSP. The NER already contains rules that provide the AER with the power to put this type of scheme in place for DNSPs. To ensure consistency in the arrangements for transmission and distribution, ENA recommends the NER be amended to contain similar DMIEGCS provisions for TNSPs.

The design of a revised DMIEGCS will require consultation between the AER and industry. As a contribution towards this process, ENA has developed recommended principles for such a scheme and is developing a draft scheme design on this basis, for consultation with the AER.

[9] NER, rule 6.6.3

2. Principles for a revised DMIEGCS

The DMIEGCS should have regard for the following:

1. Desirability of the scheme incentivising the level and scope of DSP activities likely to best promote the NEO.

2. Recognise the net benefits of DSP activities to the wider electricity industry supply chain, in addition to the benefits to the NSP and consumers.

3. Recognise the longer-term value of DSP activities, beyond the regulatory period in which the activities are undertaken.

4. Achieve economic efficiency by capturing the actual savings from particular DSP activities

5. Recognise the need for networks to build DSP capability through research, development and testing of new approaches to DSP initiatives.

6. Recognising the operation, breadth and overall financial impacts of other incentive schemes and regulatory obligations.

7. Offset negative revenue impacts that may arise under price control arrangements, and take into account impacts of the scheme on the level of risk borne by the NSP.

8. Be simple and transparent to operate and to administer.

9. Be cost-effective taking into account an assessment of the likely benefits arising under the scheme

10. The potential for the scheme to vary between NSPs or classes of NSPs (i.e TNSPs, DNSPs)

3. Preferred elements of a revised DMIEGCS

a. Incentive mechanism

This mechanism should go beyond cost recovery and embody a positive incentive payment that reflects a deemed share of the actual benefits of the DSP activity to the wider electricity supply chain and consumers, and a share of future benefits.

b. Market benefits guidance

To ensure consistency and some certainty, the DMIS could include a defined method or deemed value for the benefits of DSP activities:

1. that accrue outside the NSP boundary (ie to another network level and generation),

2. that are not directly assessable (eg NSP benefits to LV or MV feeder levels), and

3. that would accrue beyond the current planning horizon (where DSP effects are persistent).

This approach should be endorsed for use in the building blocks for five yearly regulatory determinations, for assessment of alternatives under the RIT, and for determination of the incentive value under the in-period mechanism.

c. Within-period revenue adjustment

Provide a within-period revenue adjustment for DSP initiatives arising within the regulatory period, such as those arising from the application of the RIT or other DSP initiatives not included in the revenue determination.

This mechanism could comprise a factor applied to the annual price (similar to other incentives and the NSW d-factor).

d. Innovation Allowance

Provide an expanded allowance that builds DSP capability through research, development and testing of new approaches to DSP initiatives for networks. The level of the allowance should reflect the additional research and development needed to support an increased level and breadth of network-initiated DSP activities.

energy networks association

ENA SMART METER OPERATING MODEL

FOR EMERGING ENERGY MANAGEMENT SERVICES

CONTNETS

PURPOSE

This paper sets out the ENA's current view of how new energy management services may be delivered to small customers by existing and likely new participants in the emerging operating environment of smart meters and other new technologies.

The paper also identifies areas of the operating environment that may change resulting from future policy changes (such as new roles). The ENA refers to its vision for the emerging and future operating environment as the ENA Smart Meter Operating Model[1].

CONTEXT

There is a lack of clarity around how new energy management services for small customers are likely to be delivered in the energy market, particularly with the introduction of smart meters and other new technologies. Therefore, the ENA has set out its vision for this Smart Meter Operating Model and hopes that it will assist market participants and other stakeholders to agree a way forward for the emerging operating environment and settle required policy decisions. The ENA believes that this Operating Model will facilitate delivery of benefits to small customers by providing greater clarity around roles in the emerging operating environment and encouraging competition in delivery of innovative energy services enabled by new technologies.

In developing its Smart Meter Operating Model, the ENA applied the following principles:

» The National Electricity Objective (NEO)[2]

» Distributors must meet their regulatory obligations of maintaining network functionality, integrity, reliability and security

» The ENA Smart Network Strategy Objectives:
  - Improve cost effectiveness of energy network operations and investments
  - Improve reliability, quality and security of electricity supplies
  - Create a platform for customer choice
  - Facilitate reductions in carbon emissions

» The National Energy Customer Framework (NECF) including recognising the roles and business objectives of all parties.

The Smart Meter Operating Model reflects pragmatic choices to kick start customer choice. It has been completed at a point in time reflecting the need to balance certainty with the flexibility for likely evolution. It is by no means perfect and is expected to change, particularly if policy decisions are made which change current market arrangements.

The ENA welcomes engagement by stakeholders on its proposed Smart Meter Operating Model.

1 Within this document, organisations and references are cited in terms of the National Energy Market (NEM) which applies to eastern Australia and South Australia. However, the Operating Model will be equally relevant to Western Australia through its equivalent regulatory framework.

2 "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – A) price, quality, safety, reliability, and security of supply of electricity; and B) the reliability, safety and security of the national electricity system."

CURRENT ENERGY MARKET ENVIRONMENT

The current energy market environment faces the following challenges:

- increasing demand for electricity
- increasing sensitivity to rising energy retail prices
- new technological developments such as solar photovoltaics and electric vehicles
- desires by customers to participate as both consumers and producers of electricity
- increasing access to real time data to incentivise more efficient energy management
- increasing cost effectiveness of home energy management and other technologies to reduce retail bills, and
- development of new services, such as demand management/response programs which will result in a shared responsibility for energy management, that may be delivered by distributors, retailers and/or third parties.

These challenges often result in increased cost pressures, which are difficult to manage in an environment of increased sensitivity to energy retail price increases. In particular, these challenges can result in increased complexity and/or costs for distributors in maintaining compliance to network functionality, integrity, reliability and security requirements. The ENA is keen to balance the need to minimise costs and complexity with the need to maintain system security and reliability. To this intent the ENA is developing the following two protocols to support the Smart Meter Operating Model:

1. Load Management and Network Security Protocol - to enable innovative load management processes to develop while mitigating risk to electricity supply[3] for customers and network businesses.
2. SMI[4] Communications and Data Security Protocol - to protect privacy of consumers[5] and ensure secure operations for industry businesses while enabling innovative processes to develop and mitigating risk to electricity supply for customers and network businesses in the context of Smart Metering Infrastructure (SMI).

The ENA believes that once developed these protocols will play a very important part in the emerging market in setting out the obligations of distribution businesses in maintaining network functionality, integrity, reliability and security, and will provide participants with a clearer understanding of what rights and obligations they have in requiring access to information and/or services.

3 Introduction of smart meters is expected to increase the volatility of network security as a result of load switching associated with new products offered by the market.
4 Smart Metering Infrastructure (SMI).
5 Access to SMI increases the risk of unauthorised access of customer information.

EMERGING PRODUCTS AND SERVICES

The emerging energy management services are expected to be significantly influenced by new customer experiences and product offerings, particularly with the introduction of smart meters.

Smart meters can enable some new services, including:

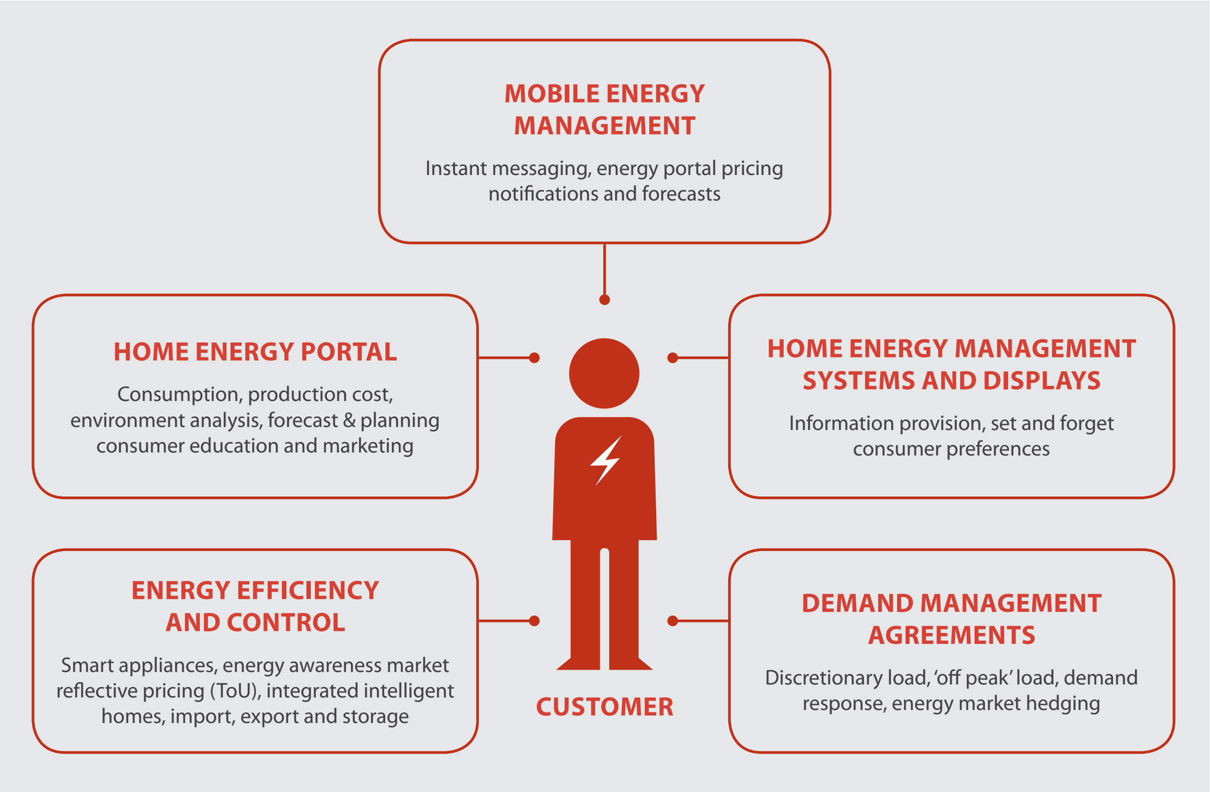
» Increasing access to real time data
» detailed customer usage, Home Area Network (HAN) registration and information updates
» speedy customer transfers and event notifications (e.g. power outages and recoveries)
» HAN enabled load control functions
» customer requested supply capacity control
» customer supply monitoring (to detect safety issues at premises)
» customised SMI metering arrangements to customers for use with micro generation or cogeneration and with energy storage and electric vehicles.

Some of these services may require development of new business relationships and procedures.

The Smart Meter Operating Model assumes that distributors, retailers and new third parties will provide new energy management products and services utilising new technology and pricing structures.

Web-based information services will analyse consumption data and prices for customers. Home energy management (home area network or HAN, see Attachment 1 for more detail) systems will use this information to control appliances. Customers will be able to aggregate or sell their load interruptibility to firms that trade contracts in the wholesale energy market. In addition, distributors may choose to provide demand management services direct to customers (for example to enable deferral of network augmentation such as is enabled now by off-peak hot water services).

FIGURE 1 **SHOWS THE LIKELY CUSTOMER EXPERIENCE AND EVOLVING SERVICES IN THE EMERGING MARKET.**



For the network services and retail energy markets to flourish and create efficient outcomes, distributors, retailers and third parties each need to be able to freely participate in providing energy management services and, if they choose, to:

» have a direct relationship with customers

» interactively offer their products and services, communicate their benefits to customers, and perceive the customer response

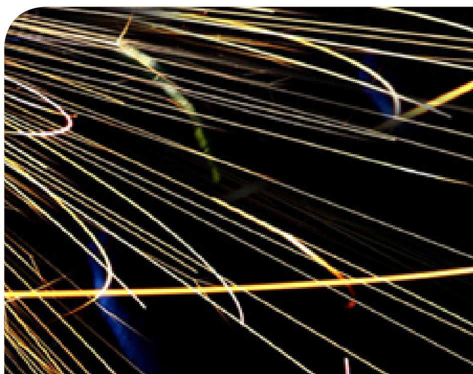
» make the commercial investment decisions necessary to provide customer value and bear the appropriate level of risk.

At this time, the energy market is at a relatively immature stage with these technology-enabled energy services and network businesses can provide value in facilitating energy service delivery as the potential new relationships and processes evolve. The most effective outcome for the market will be products and services that integrate the needs of all participants otherwise the outcome could cause instability in energy supplies. There is also a need to recognise that each distributor's network has physical limits including demand and in-flow of localised generation (hence the need for the load management and security protocols).

Therefore, the Smart Meter Operating Model provides for facilitated access by accredited parties, e.g. retailers, customers and third party providers, to the smart meter enabled services (based on agreed protocols) to enable competition in customer service provision in the retail energy market. It also enables networks to provide energy management services as part of their regular network services.

The Smart Meter Operating Model assumes that there will be no restriction on other parties utilising their own devices to support their commercial objectives provided that these devices do not interfere with distributors' ability to perform regulatory obligations in network services and metering. However, the Operating Model assumes that distributors must have priority access (i.e. direct access) to SMI functions for the purpose of managing network security.

Access to services enabled by SMI technology by accredited parties is likely to require substantial investment, both in terms of initial capital cost and in terms of on-going transaction and coordination costs. Lower cost alternatives exist to meet the needs of retailers and third parties to monitor and manage load, and to communicate to customers. In some cases, these alternatives can already provide higher performance levels than current SMI technology. These alternatives are expected to continue to grow rapidly and they will provide effective and increasing competition to energy service developments dependent on SMI metering access. Therefore, the Operating Model also assumes that these alternative products will be offered to customers.



DISTRIBUTION BUSINESS DRIVERS

Regardless of the operating environment, distributors must meet their regulatory obligations. In development of new products and services by retailers and third parties, it is critical that such products and services do not prevent or obstruct the essential service obligations of the distribution businesses under National Energy Retail Law (NERL), National Energy Customer Framework (NECF) and National Electricity Rules (NER) (for example relating to maintenance of supply with regulated levels of reliability and quality and fault response services).

In the Smart Meter Operating Model, distributors establish smart metering with communications and back office systems as a part of an SMI solution. To achieve scale and scope efficiencies, a distributor is likely to use the same dedicated communications network for its SMI solution and other elements of its Smart Network. Smart Networks will provide an improved customer experience, including monitoring supply continuity, managing energy flows (including embedded generation), power factor and power quality monitoring issues.

The Smart Meter Operating Model assumes that smart meters are a service/system enabler; that is, it is not the smart meters themselves that provide market benefits and new services for customers but they will form an important part of the distributor’s Smart Network which will enable the market and customer benefits to be achieved.

The ENA Smart Meter Operating Model has been developed to enable benefits to be realised along the entire energy supply chain – from generator through to customer. Maximum benefits can be achieved if the smart meter is an integral part of the distributor’s Smart Network.

In the current environment, distributors are primarily responsible for provision of meters to small customers. This position is assumed to remain unchanged in the Smart Meter Operating Model but the ENA notes that future contestability of smart meters is subject to policy review, with an outcome expected in 2013.

RETAILER BUSINESS DRIVERS

Retailers require access to SMI for better quality and more timely information in order to provide competitive services to their customers.

The Smart Meter Operating Model assumes that retailers will:

» continue to meet their regulatory obligations (such as in NERL, NECF and NER)

» be provided with facilitated access to the SMI by distribution businesses under regulated relationships and contractual agreements

» have the ability to send and receive messages to/from the Utility HAN devices to manage customer load

» develop new energy service products delivered directly to customers without requiring SMI facilitation by distributors (eg over internet portals, via smart phones, etc)

MARKET ROLES

Figure 2 sets out the technology architecture assumed in the ENA Smart Meter Operating Model.

The supporting roles of each participant for the technology architecture in the Smart Meter Operating Model are set out below.

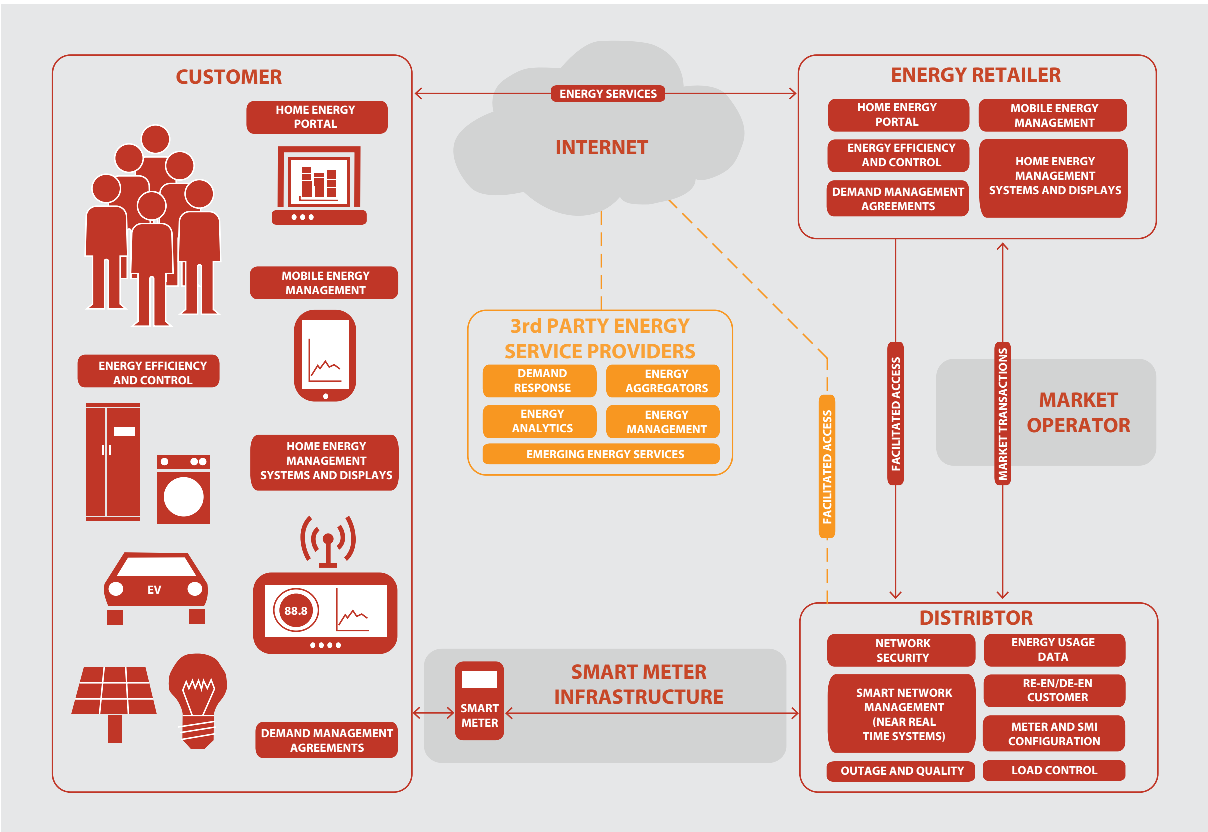
Distributors:

» consistent with NERL, NECF and NER, distributors provide regulated network services directly to customers (see Attachment 2 for NECF triangular relationship)

» maintain network functionality, integrity, reliability and security in accordance with regulatory obligations and the Load Management and Network Security Protocol and SMI Communications and Data Security Protocol

» provide smart meters for small customers until there is a policy position to support contestability

FIGURE 2 **EMERGING TECHNOLOGY ARCHITECTURE**



» establish smart metering communications and back office systems as a part of an SMI solution, which in turn may be part of an integrated Smart Network

» provide facilitated access to SMI via Market Systems (provided by the Australian Energy Market Operator, AEMO) to retailers and third parties on a non-discriminatory basis

» use SMI in developing their management platforms (smart network management, monitoring, protection and control systems) for network operations and asset planning

» may offer network services (e.g. load management) to customers in order to change customer consumption patterns to optimise network utilisation and delay network augmentation

Retailers:

» consistent with NERL, NECF and NER, retailers continue to supply energy to customers, including retail products and services that may change customer consumption patterns

» where required, obtain facilitated access to the SMI through Market Systems maintained by AEMO

» develop new energy service products delivered directly to customers without requiring SMI facilitation by distributors (eg over internet portals, via smart phones, etc)

Accredited third parties:

» provide energy management products and services to customers, independently or in cooperation with retailers, in compliance with NERL, NECF and NER requirements

» where required, obtain facilitated access to the SMI through Market Systems maintained by AEMO

CUSTOMERS

The ENA has developed the Smart Meter Operating Model with the objective of delivering the benefits of emerging energy management services to consumers within the existing market arrangements.

The Smart Meter Operating Model seeks to provide a framework to assist consumers to make informed choices about how much electricity they use at different times. Customers may choose different ways to engage with new energy management services, where they wish to achieve this outcome.

The model provides access for accredited parties to provide energy management services; that is, retailers, customers and third party providers will have access to the smart meter enabled services thus increasing competition in the provision of these services. Distributors will continue to provide energy management services as part of their network services.

Some of the existing market arrangements may change once expected policy decisions are made. The Smart Meter Operating Model has been developed with this in mind and has the flexibility to accommodate change.

ENGAGEMENT

The ENA welcomes engagement by stakeholders on its proposed Smart Meter Operating Model.

ATTACHMENT 1:
HOME AREA NETWORK (HAN)

To give more context to how an operational model will need to be deployed a brief description of the potential physical environment has been included in respect to a consumer's premise. There are three basic scenarios for the physical operation of the HAN:

Consumer HAN: This is the predominant configuration at present where a customer establishes its own HAN without the need for external providers and therefore without the need for Energy Service Interfaces (ESI's). The limited external connectivity minimises security requirements.

Utility HAN: A utility HAN would require the presence of a Utility ESI which could be deployed as a gateway or directly in a meter. The consumer could request services from a utility provider which would then register the consumers' devices with the ESI creating a Utility HAN. The security requirements will be dictated by the needs of the Utility ESI as well as any other ESI's with which it needs to communicate. These are likely to be the most stringent security requirements for all of the HAN models.

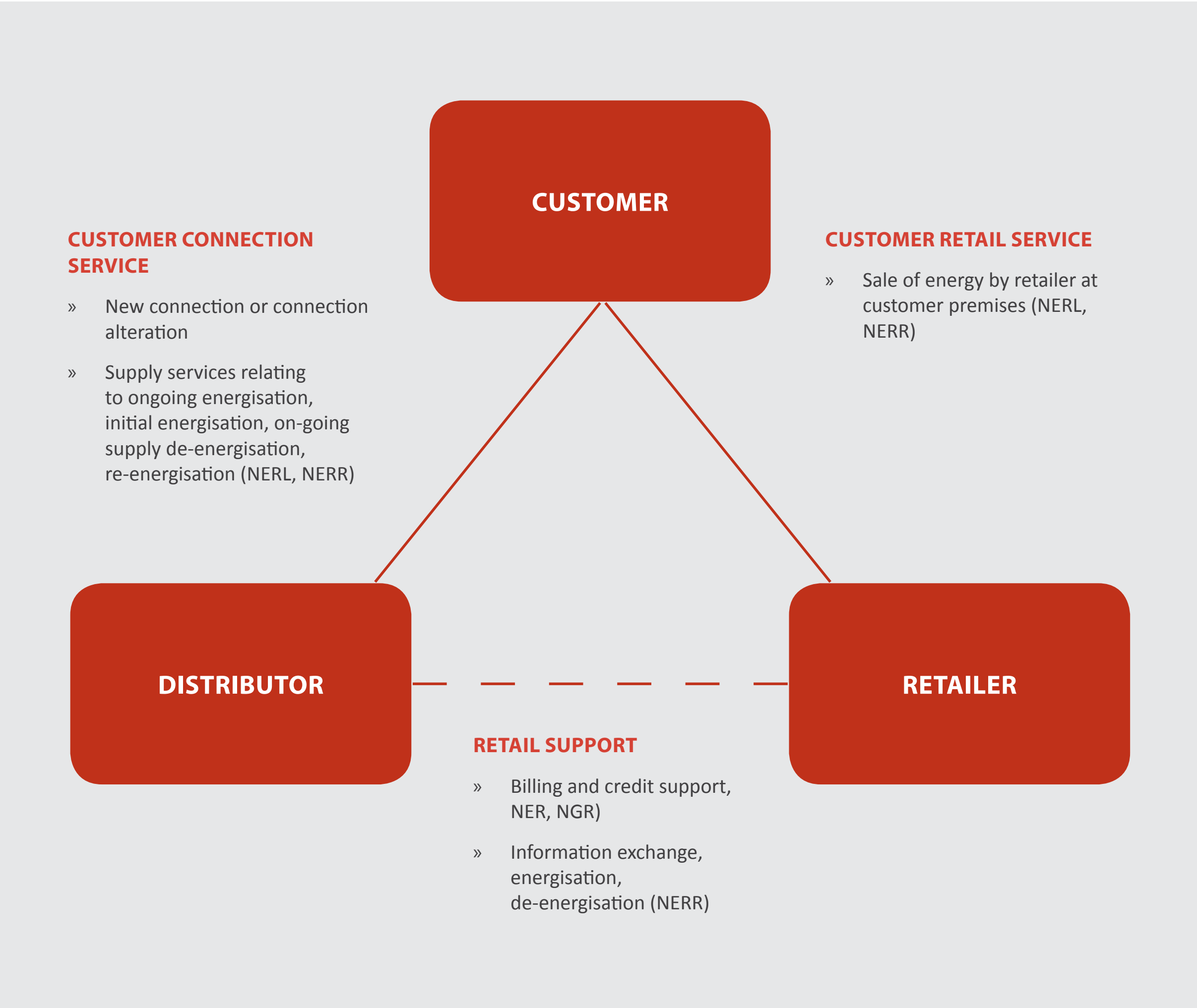
Third Party Provider HAN: The consumer could request services from a Third Party Provider which would then register the consumers' devices with their ESI creating a Provider HAN. The security requirements will be dictated by the needs of the Provider ESI.

The future HAN is likely to be a hybrid of the basic scenarios:

- To provide effective service times for response of equipment to an event, or to a lesser extent a price signal, a Utility HAN would provide the best solution as a Provider HAN would require too many back office operations to deliver effective response times.
- Utilities would not want to bear the burden of registering all the devices that a consumer would have and hence registration would likely be limited to items such as major loads / generation sources (e.g. other meters, solar PV, batteries, electric vehicles, pool pumps and air conditioners).
- Other equipment could be connected to a Provider HAN which could deliver a control service to minimise energy costs through price controls.
- Information may also be sourced through the Utility ESI through an appropriately registered device to provide the drivers for a Consumer HAN which has an in-home energy management system.
- Equipment could be attached to both Utility and Provider HANs resulting in a requirement for a hierarchical control philosophy. Utility HAN requirements to maintain stability in the network would take priority.
- Utilities could also provide a mechanism for retailers to deploy messaging or signals through their back office systems through to the ESI provided they comply with protocols and are appropriately verified (this is already the case for energisation and de-energisation).

The ENA recognises the current Victorian HAN process as an example of a hybrid system. The process is promoted under the Victorian Government's Energy Efficiency Target (VEET) initiative. The intent of the initiative is to encourage utilisation of HAN devices to deliver information services to consumers to enable them to manage their energy usage, recognising the critical need at this early stage of technology development to ensure compatibility of the HAN devices to network meters.

ATTACHMENT 2:
NECF TRIANGULAR RELATIONSHIP



energy networks association

Energy Networks Association Ltd
P +61 2 6272 1555 **F** +61 2 6272 1566 **E** reception@ena.asn.au
Level 3, 40 Blackall Street, Barton ACT 2600

www.ena.asn.au

Load Management and Network Security Protocol

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Status:	**Draft**
Author:	ENA
Date published:	15 March 2012
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Table of Contents

1 Document Control

1.1 Version Control

Version	Date	Description	Amended by
0.1	15 March 2012	Draft	ENA

1.2 Approval

Authorised by	Signature	Date

1.3 References

The following documents are referred to in this document.

Document Name	Version
SMI Communications and Data Security Protocol Principles	
AEMC Issues paper: Power of Choice – giving consumers options in the way they use electricity	

2 Introduction

Load management within electricity networks is becoming increasingly available with the introduction of smart meters, smart appliances and enhanced communications linkages.

Traditionally, load management within electricity networks has involved managing relatively few large customer sites with agreed contractual and physical arrangements and/or managing hard wired loads (such as domestic electric hot water services) to shift electricity demand into off-peak periods with a financial incentive to consumers.

As load management is further enabled by new technologies for households and small businesses, the movement into and out of the networks by aggregation of significant amounts of loads from small premises has the potential to destabilise electricity supply and power quality, with significant potential impacts on customers at local levels.

In considering principles to guide engagement between the parties in the energy market, the need for a load management protocol was identified, in recognition that an ever-increasing number of parties were likely to seek to control electricity load for different purposes.

The Energy Networks Association is developing a draft Load Management and Network Security Protocol (the **Protocol**) to enable innovative load management processes to develop while mitigating risk to electricity supply for customers and network businesses.

Development of the Protocol commenced within discussions between distribution and retailer energy businesses and consumer representatives within the National Smart Metering Program (NSMP).

The Ministerial Council on Energy (now Standing Council on Energy and Resources) decisions of the 13 December 2007 and 13 June 2008 set out the expected outcomes of smart metering in the NSMP:

- Reducing demand for peak power, with consequential infrastructure savings (e.g. network augmentation and generation)
- Driving efficiency and innovation in electricity business operations, including improving price signals for efficient investment and contracting
- Promoting the long term interests of electricity consumers with regard to the price, quality, security and reliability of electricity
- Promoting competition in electricity retail markets
- Enabling consumers (including residential, business, low- and high-volume users) to make informed choices and better manage their energy use and greenhouse gas emissions
- Manage distributional price impacts for vulnerable consumers
- Promoting energy efficiency and greenhouse benefits
- Providing a potential platform for other demand side response measures and avoiding discrimination against technologies, including alternative energy technologies

This Protocol recognises these objectives and takes account of Council of Australian Governments (COAG) commitments, MCE policy direction, the market objectives and consultation with stakeholders.

The Protocol is intended to support the aspirations of multiple parties to develop products to both benefit customers and support their commercial needs, while maintaining the obligations of distribution businesses to ensure power quality and supply to customers.

The Protocol will evolve over time as parties in the energy market gain experience in development and application of load management techniques and products. For example as electric vehicles become more prevalent, their utilisation and impact both on electricity storage and timing of electricity demand will significantly affect electricity supply parameters in currently unpredictable ways.

2.1 What is Load Management

Load management is the process of balancing the supply of electricity or capacity on the network with the demand, by adjusting or controlling the load (demand) rather than the power station output or adding additional network capacity.

When the load on a system approaches the maximum generating capacity or maximum network capacity, network operators must add additional capacity or find ways to curtail the load. If they are unsuccessful, the system will become unstable and blackouts can occur.

Load management also allows energy utilities to reduce demand for electricity during peak usage times, which can reduce costs by eliminating the need for additional power stations or network capacity to manage peak loads.

Peak loads generally occur during extreme weather events and may only apply for several days per year. However, the additional electricity supply capacity to service such peak loads can be expensive to provide, adding to the price burden for customers while being unused for most of the year.

Load management may also be undertaken by individual customers to reduce their electricity usage to manage costs or even to manage environmental impacts, such as greenhouse gas emissions.

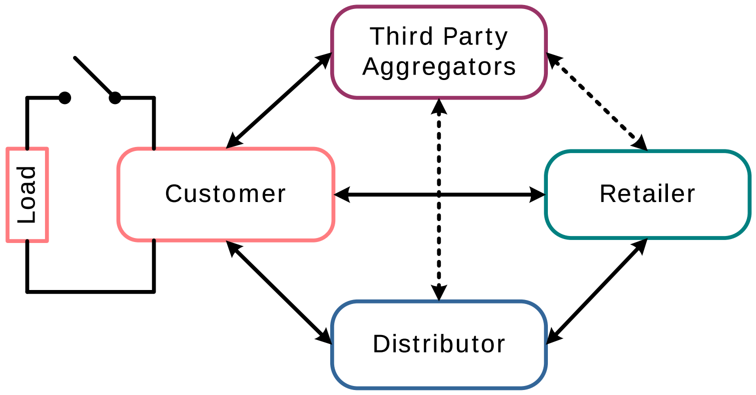
Loads may be managed by techniques such as:

Switching on/off 'controlled loads' including customer appliances wired to switching devices (load contactor or relay contacts) in the meter eg off peak hot water, slab heating, direct air conditioning control or Demand Response Enabling Device (DRED).

Switching on/off customer appliances within the home or business, including via Home Area Networks (HAN) or via a smart meter (ie not hard wired)

Use of retailer / third party provided contactors external to the meter to remotely disconnect or reconnect immediately or through a supply capacity control function (eg to reduce the supply amount by an agreed percentage rather than close an appliance down completely).

The Protocol covers the arrangements for retailers, distributors and third parties to control load and manage the impact of the switching of load on the distributor's network using any of these methodologies.

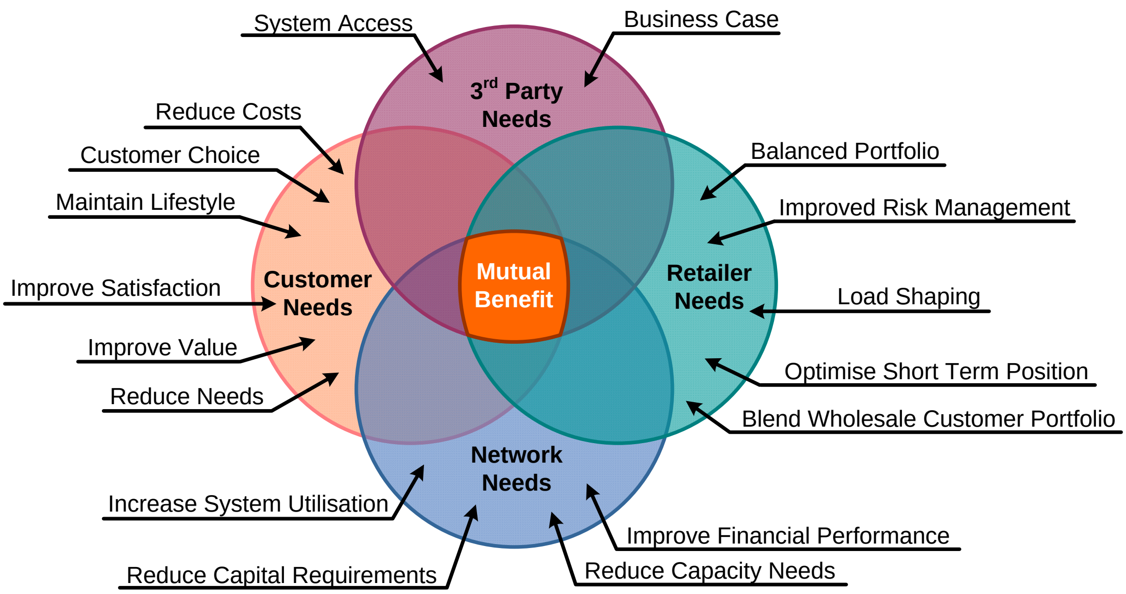


2.2 Purpose of the Protocol

The purpose of the Protocol is to ensure integrity, reliability and sustainability/security of the distribution network whilst allowing distributors, retailers and third parties to participate in load management and demand response initiatives.

The protocol recognises the different drivers that face distributors, retailers and customers, which are illustrated in the following diagram.

Value Proposition for Load Management



3 Benefits and Risk of Load Management

3.1 Benefits

As is noted in the AEMC Demand Side Participation (DSP) Stage 3 review, DSP can have significant benefits.

> *"Cost effective DSP has the potential for electricity users to more effectively manage the cost of their consumption as Australia's energy markets undergo a period of change and transition to a low carbon economy. Cost effective DSP has the potential to improve the efficiency of the electricity market, for example through more efficient utilisation of transmission and distribution networks, provide for greater efficiency in consumption, and providing added competitive discipline on retailers"*[1].

However, deferred capital investment for network support can only be realised if the Load Management response is assured. Opt out (override) load management products do not support capital investment deferment

[1] AEMC Issues paper: *Power of Choice – giving consumers options in the way they use electricity*, 15 July 2011, p. 13

3.2 Risks

Whilst networks are designed to facilitate variations in load including those due to switching of load,, synchronised switching of aggregated customer load in and out of service has the potential to destabilise the distribution network supply of electricity to customers which may result in:

Technical Risks

Network Interruption - poorly managed load control can result in network protective devices (eg. fuses) operating and causing unnecessary outages for customers. This also results in unnecessary costs for response by the distributor.

Damage to Network Equipment - poorly managed load switching can result in overloading of lines, transformers or other major network components. Such overloading can cause plant failures and this will inevitably result in long duration outages for customers.

Voltage Variation - switching of loads in the network without adequate control can result in significant voltage variation at customer premises. This means that customers will see flickering lights and that some appliances will perform poorly and in extreme cases can fail.

Damage to Customers Equipment - poorly managed load control can result in power quality issues including voltage variation as above. Further to this, frequent and uncontrolled switching of customer appliances can cause premature ageing and failure of those appliances.

Commercial / Market Risks

Market Price Spikes – the uncontrolled addition of large amounts of load to the electricity market can result in price spikes that may result in higher prices. Such addition of load can occur by poorly managed return of load that has been previously switched off for load control purposes. In many instances load being returned after some time of can be of much greater magnitude than that switched off (due to the loss of diversity).

Conflicting Objectives of Multiple Participants – in many instances, there will be good alignment between multiple market participants, for example where all parties (network, retailer and customer) being benefited by load reduction during peak demand periods. However at other times, retailers may benefit from wholesale market conditions if the controlled load is returned during peak demand periods. Such examples may put market participants at conflict over load management.

Extent and Duration of Load Control – network operators may wish to limit the extent of load control switching due to the difficulties of returning large amounts of controlled load to the network. For example, large scale shedding of hot water demand during peak winter demand periods may result in much higher demand that needs to be restored. The longer the duration of the controlled period, the greater the load to be restored (since all load diversity is lost over time). In some instances, this may make it almost impossible to restore all load without major network disruption or additional costs for more network switching.

4 Principles of Load Management

In accommodating this wide range of participants and diverse needs, the protocol requires several key principles established to assure:

1. Customers 'own' the right to control of their loads and customer contracts, deemed or explicit, are the underlying driver and must be respected.
2. Networks should facilitate the development and implementation of load management to support customer interests.
3. Network regulated power quality and reliability standards must be protected, irrespective of commercial arrangements. Whilst networks are designed to facilitate variations in load including those due to switching of load, any synchronised switching operation that is likely to compromise network regulated power quality and reliability standards must not be carried out. All switching operations for the purposes of load control must be done after consideration of network constraints.
4. When switching a large load group (one or many customers) exceeds the prescribed threshold within a single distribution business, that large load group shall be registered and discoverable by the distribution business along with the established controls to prevent network instability. For example spatial separation of a large load group being operated will diminish the potential for network impact.
5. Each Distribution Business shall make available its business rules for acceptable load management switching operation including:
    a. the registered aggregated load threshold (eg 10MW),
    b. the capacity of load management unloading (eg 10MW),
    c. the capacity of load management loading(eg 5MW),
    d. the minimum duration of a switching operation (eg 5min),
    e. the maximum frequency of switching operation (eg 15min)
    f. and any special considerations for that network or region to ensure network stability through switching operations.
6. Where a distribution business becomes aware of a load switching operations that risk network regulated power quality and reliability standards, the affected distribution business may block, prevent or override the operation being executed to ensure security of supply (loading or unloading).
7. Network infrastructure has been developed based on the availability of existing load control systems and any new load management implementations should not inadvertently remove or reallocate those realised load management benefits elsewhere. For example peak demand has reduced through hot water load control and investment in network capacity has in turn been reduced, consequently the customer benefits from a reduced service cost.. While it is recognised that customers can change their load control, market participants should be mindful that the removal of such peak demand control will drive investment in peak network capacity and a higher consumer cost. Commercial considerations need to be balanced with the need for overall market efficiency.
8. Facilitated access to load control should be encouraged to enable a greater range of products and services to enable better customer outcomes, though lower peak demand and greater control of consumption.
9. Network operators should expeditiously assist other market participants to engage in load management activities, subject to the limitations of the technology available in that network.

10. Where load control technology does not enable an individual retailer or third party load control, then agreements may be put in place to enable that parties agreed load control parameters to be operated by another enabling party.
11. If a conflict emerges between competing interests in load control, then provided network regulated power quality and reliability standards are not compromised then overall market benefit considerations) will prevail.
12. Where load management is facilitated by access through network infrastructure, service level agreements will be integral to its application to reflect obligations undertaken in the interaction of two or more parties.
13. Where investments have been made in monopoly infrastructure to support load control, then operation of load control should utilise this infrastructure where feasible to avoid stranding or write-off of assets that have already been funded by customers.
14. All parties engaged in load control must utilise the communications and data security protocols in place.
15. All processes and transactions need to be documented and auditable.

SMI Communications and Data Security Protocol Principles

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Table of Contents

1 Document Control

1.1 Version Control

Version	Date	Description	Amended by
0.1	15 March 2012	First Draft for NEICF review	ENA

1.2 Approval

Authorised by	Signature	Date

1.3 References

The following documents are referred to in this document.

Document Name	Version
Smart Metering Infrastructure Minimum Functionality Specification (SMIFS)	SMI FS Version 1.3
[ZigBee SEP 2.0 Document/s]	To be released

2 Introduction

The Energy Networks Association is developing a Communications and Data Security Protocol (the **Protocol**) to protect privacy of consumers and ensure secure operations for industry businesses while enabling innovative processes to develop and mitigating risk to electricity supply for customers and network businesses in the context of Smart Metering Infrastructure (SMI).

Development of the Protocol commenced within discussions between distribution and retailer energy businesses and consumer representatives within the National Smart Metering Program (NSMP). In considering principles to guide engagement between the parties in the energy market, the need for a security protocol was identified in recognition that new technologies provided security challenges with the addition of significant communications interfaces between multiple parties.

The Ministerial Council on Energy (now Standing Council on Energy and Resources) decisions of the 13 December 2007 and 13 June 2008 set out the expected outcomes of smart metering in the NSMP:

- Reducing demand for peak power, with consequential infrastructure savings (e.g. network augmentation and generation)
- Driving efficiency and innovation in electricity business operations, including improving price signals for efficient investment and contracting
- Promoting the long term interests of electricity consumers with regard to the price, quality, security and reliability of electricity
- Promoting competition in electricity retail markets
- Enabling consumers (including residential, business, low- and high-volume users) to make informed choices and better manage their energy use and greenhouse gas emissions
- Manage distributional price impacts for vulnerable consumers
- Promoting energy efficiency and greenhouse benefits
- Providing a potential platform for other demand side response measures and avoiding discrimination against technologies, including alternative energy technologies

This Protocol recognises these objectives and takes account of Council of Australian Governments (COAG) commitments, MCE policy direction, the market objectives and consultation with stakeholders.

The Protocol is drafted with reference to organisations and regulation within the National Energy Market (NEM), although its application should be equally relevant to Australian jurisdictions outside the NEM (such as Western Australia) with appropriate changes in references.

The Protocol is intended to support the aspirations of multiple parties to develop products to both benefit customers and support their commercial needs, while maintaining the obligations of distribution businesses to ensure power quality and supply to customers. The Protocol will be negotiated with the relevant parties to support their needs and aspirations in the energy market.

The Protocol will evolve over time as the parties in the energy market gain experience in development and application of products and services.

2.1 Use of Italicised expressions

Italicised expressions in this protocol are defined in the glossary in Appendix A.

2.2 SMI Communications and Data Security Objectives

The key objectives for communications and data security in the context of smart metering infrastructure relate to ensuring that:

- **Confidentiality** is maintained in that access is restricted to authorised parties.
  This includes ensuring that the rights of consumers to privacy of their personal information from unauthorised access and use is maintained;
- **Integrity** of data remains and can only be modified or deleted in authorised ways. Parties accept their obligation to undertake best endeavours to provide accurate information and retain integrity whilst stored, during transformation and in transmission. All elements of the Smart Metering Infrastructure and related communications are maintained in an appropriately secure manner from unauthorised and inappropriate external access.
- **Availability** of assets and information to the authorised parties in a timely manner.
  All authorised parties have timely access to relevant information required to perform their functions and responsibilities.

The Protocol recommends addressing these objectives on a risk assessment basis.

2.3 Communications and Data Security Protocol Scope

The Communications and Data Security Protocol (**The Protocol**) intends to recommend high level security for Meter to Market participant and Customer as depicted in Figure 2-1.

The Protocol references the structure and scope of the national Smart Metering Infrastructure Minimum Functional Specification (SMIFS) v.1.3.

The Protocol scope includes

a) Classification of SMI Data and Services

b) Privacy and Data Principles

c) Facilitated Access Principles

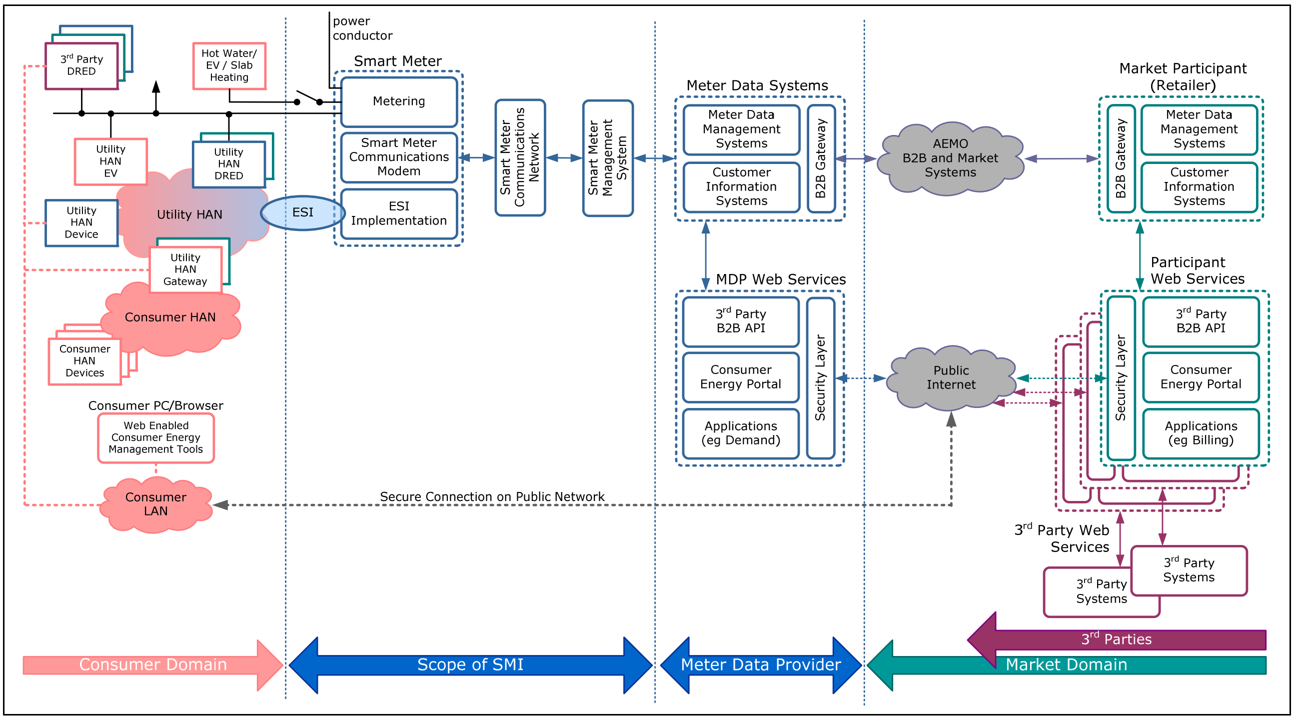
All SMI Communications and Data Security Requirements identified in the SMI Functional Specification v1.3 (or later equivalent) are standing principles to be adopted by the protocol.

The Protocol is designed to cover perceived gaps in communications and data security relating to smart metering infrastructure aspects of the energy market operations. It is not intended to duplicate or replace existing processes and responsibilities.

The Protocol recognises that end to end integrated systems are likely to be multi sourced and implemented over various platforms and as such this protocol remains largely agnostic on technology implementation and rather prescribes a set of guiding principles to be applied jointly with a best practice risk assessment methodology.

However the Protocol assumes that the distribution business is the principal operator of the SMI. For the purposes of this Protocol, it is assumed that the distribution business provides facilitated access of SMI enabled services to other parties.

Figure 2-1: SMI Landscape Meter to Market Participant and Customer



For the purpose of this document the ***SMI Landscape*** components are defined as follows*:*

a) ***Smart Meter*** means a device complying with Australian Standards which measures and records the production or consumption of electrical energy and also conforms to the minimum functional requirements (SMIFS).

b) ***Smart Meter Management System (SMMS)*** means the component of an SMI system that allows commands and messages to be exchanged with the smart meter via the Smart Meter Communications Network (SMCN).

c) ***Smart Meter Communications Network (SMCN)*** means all communications equipment, processes and arrangements that enable remote communications between the smart meter and the SMMS.

d) ***Home Area Network (HAN)*** means a Local Area Network (LAN) established within the customer premises.

e) ***Energy Services Interface (ESI)*** means a secure interface within the Smart Meter for HAN devices. (For a more extensive definition see the glossary definition for ESI and ESI Implementation.)

f) ***Utility HAN*** means a *HAN* containing a Utility-managed *ESI* and the *HAN devices registered* on that *ESI* (for example an ESI to service a water meter),

g) ***Utility HAN Device*** means a device registered to the Utility HAN and managed by another party other than the customer eg a Utility-managed Demand Response Enabling Device (DRED).

h) ***Consumer HAN Device*** means a device registered to the Utility HAN or Consumer HAN that the consumer manages, for example, an In Home Display (IHD).

i) ***HAN Gateway Device*** means an intelligent device bridging between networks and/or systems, for example an energy management system may collect and publish consumption data to a consumer energy portal.

j) ***Local Port*** means a physical communications port of the Smart Meter (Optical, Serial, Ethernet, Wireless or equivalent local interface)

k) ***Consumer Energy Portal*** means a public facing energy portal providing consumption data and energy related services.

l) ***B2B AEMO Interface*** means existing Business to Business procedures with Market participants

m) ***Bilateral Interface*** means Business to Business Interfaces bilaterally agreed between Market Participants and/or 3rd Parties to facilitate secure access to systems and services.

n) ***Public Internet*** means a public uncontrolled (non-prescribed) communications network (nominally the internet, but may be an intranet).

2.4 Limit of These Protocol Principles

This protocol is limited to identified SMI enabled services, SMI enabled functionality and access to the data that is derived from the SMI and associated systems. As an enabling technology the Protocol is limited to those services and data purposes available or envisaged at the time of defining the Protocol.

For clarity specifically and intentionally excluded scope is identified below with supportive reasoning

Out of Scope elements are including but not limited to:

- ***SMI Items defined by other parties***: as identified in Table 2.1 SMI Landscape Security Domain
- ***Consumer HAN –*** the Consumer domain is outside the control of the SMI. However this does not prohibit a party for offering services and taking on additional responsibilities
- ***Bilateral Application Programming Interface (API)*** - API Technical definition is beyond protocol principles
- ***Service and Performance levels*** – describes the minimum performance in terms of quantity, quality and time required for a function to be performed by the Solution.
- ***B2B Procedures*** existing services within the energy market as defined by AEMO published B2B Procedures

2.5 Security Domains

The following table identifies coverage of security aspects of elements of the SMI Landscape Domain, identifying in particular the elements that are intended to be covered by the Protocol (i.e. perceived current gaps).

Table 2-1: SMI Landscape Security domain

SMI Landscape Domain	Security Requirements Defined in
Smart Meter	SMIFS
Smart Meter Management System (SMMS)	SMIFS
Smart Meter Communications Network (SMCN)	SMIFS
Home Area Network (HAN)	SMIFS and ZigBee SEP2.0
Energy Services Interface (ESI)	SMIFS, ZigBee SEP2.0 and **The Protocol**
Utility HAN Device	ZigBee SEP 2.0
Utility HAN Gateway	ZigBee SEP 2.0
Local Port	SMIFS and **The Protocol**

SMI Landscape Domain	Security Requirements Defined in
Consumer Energy Portal	**The Protocol**
B2B AEMO Interface	AEMO B2B Procedures
Bilateral interface	**The Protocol**
Consumer HAN	eg ZigBee SEP 2.0

3 SMI Enabled Services

This section identifies categories of SMI data, services, authorised parties and authorised purposes in order to develop an authorisation matrix to guide development of communications and data security principles in Section 4.

3.1 Data and Service Classification

The following table covers identified SMI enabled data and services.

Table 3-1: SMI Enabled Data and Service Classification

Data or Service	Type	Definition
Consumption Data	Data	Energy Data, Interval Data, Accumulator Values (Consumer) Includes Water & Gas metering Include local generation (eg PV) data
Outage Events	Data	Loss of electricity supply events recorded by the meter
Quality of Supply Events (Electricity, Water or Gas)	Data	Quality of supply events recorded in the meter event log (eg voltage sag)
Supply Capacity Control	Service	Activate / Deactivate a Supply Capacity Control function of a meter
Emergency Supply Capacity Control	Service	Activate / Deactivate a Emergency Supply Capacity control function of a meter
Load Control (Single)	Service	Load Management action to a single device (Load or Unload)
Load Control (Group)	Service	Load Management action to a group of devices (Load or Unload)
Bind/Unbind Consumer device to Utility HAN	Service	Bind request for a consumer device to the Utility HAN. eg IHD, HAN Dongle, Gateway or Smart Appliance
Bind/Unbind Utility device to Utility HAN	Service	Bind request for a utility device to the Utility HAN and associate utility controlling party. eg DRED, Water Meter, EV, or a remotely managed PCT
Status Check Utility HAN device	Service	Report status of a device connected to Utility HAN

Data or Service	Type	Definition
HAN Text message	Service	Unidirectional text message delivered to an individual device or broadcast to multiple devices in the utility HAN
Publish Tariff	Service	Push tariff/price information eg push a tariff or advise a critical peak price (CPP) event
List Utility HAN Devices	Service	Discovery of Utility HAN devices
Change meter settings	Service	Update a configurable parameter of a meter (where permitted)
Energy Portal	Service	Internet Presentation of Consumption Data, Network Events and Energy Saving analytics eg load profile, outage information, planned outages, and energy tips to the customer
Operational Diagnostics	Data	Operational measurements and diagnostics recorded or initiated from the meter or attached device eg. Signal strength of a HAN device
Authorise/ De-authorise Service	Service	B2B interface to update the records of the Authority Register

3.2 Authorised Parties

The following table indicates authorised parties for the purposes of the Protocol.

Table 3-2: Authorised Parties

Authorised Party	Party Definition
Customer	Electricity Account Holder
Market Participant	Normally the consumer's registered Retailer; Could also be an Energy Aggregator or Generator
Distribution Business	Electricity Distribution Business
Meter Data Provider	As defined by National Electricity Market Rules
Market Operator	Eg AEMO, Essential Services Commission of Victoria, and associated regulatory authorities
Authorised 3rd Party	Authorised by consumer or market participant
Delegated Agent	Authorised Delegate to act as any role above

3.3 Authorised Purpose

The following table develops an authorisation matrix, indicating which authorised parties have access to which data and services on what basis. Each party must consider the impact of the Privacy Act and NEM Rules for how they may use energy data or services.

The matrix indicates categories of:

> ***Implied Authority:*** the Primary purpose of data or service provides an implied authority for the authorised party or designated owner of the service through jurisdiction, regulation or law.
>
> ***Explicit Authority:*** by agreement where the root authority provides informed consent (or delegate thereof)
>
> ***Not authorised:*** no access
>
> ***Root Authority:*** is the party that holds the right to provide or withdraw consent to other parties. For example the consumer owns the right to grant access to their own consumption data to any other party.

Delegated Access is where the Authorised Party has explicitly authorised another party to act as an agent to handle the data or service on their behalf. It is assumed that any party may delegate their authority. Similarly, delegated authority may be revoked or may expire. Delegated authority must be for a purpose/role. A Delegated agent cannot exceed the level of authority of the delegating party.

Each authority must have an explicit purpose. Authority should not be granted to any party without constraining how the service/data is to be used under that authority. Any party may fill multiple roles.

'Not authorised' means nominally not provided, but may be provided by agreement. In some cases authorisation may be granted to de-identified or aggregated data.

Table 3-3: Authorisation Matrix

Table Symbol Legend
✓ implied authority
○ explicit authority
× not authorised
● root authority

Service or Data	Customer	Market Participant	Distribution Business	Meter Data Provider	Market Operator	Authorised 3rd Party
Consumption Data	●	✓	✓	✓	✓	○
Outage Events	✓	✓	●	✓	✓	×
Quality of Supply Events	×	○	●	✓	○	×
Supply Capacity Control	N/A	○	●	×	×	×
Emergency Supply Capacity Control	N/A	×	●	×	×	×
Load Control Single/Group	●	○	○	×	×	○
Bind/Unbind Consumer device to Utility HAN	●	○	○	×	×	○
Bind/Unbind Utility (non-meter) Device to Utility HAN eg DRED	●	○	○	×	×	○
Bind/Unbind Water/Gas Meter to Utility HAN	N/A	×	●[1]	×	×	○
Status Check Utility HAN device	●	○	✓	×	×	○
Status Check Utility Device on Utility HAN (inc Link Quality)	●	○	○	×	×	○
Status check Water/Gas Meter on Utility HAN	×	×	●	×	×	○
HAN Text Message	●	○	○	○	×	○
Publish Tariff	✓	●	○	○	×	×
List Utility HAN Devices	●	○	○	✓	×	○
Change meter settings	×	○	●	✓	×	○
Energy Portal[2]	○	●	●	●	×	○
Operational Diagnostics	×	○	●	✓	×	○
Authorise/de-authorise service	✓	○	●	○	○	○

[1] May be water /gas utility seeking connection of their meters
[2] Whichever is the service provider of the Energy portal is the root authority, only one root authority is permissible per portal

4 Communication and Data Security Protocol Principles

4.1 General

4.1.1 All systems and transactions shall comply with the Privacy Act and National Privacy Principles.

4.1.2 All interparty communications and transactions shall occur in a secure manner.

4.1.3 Privacy Impact Assessments (PIA) should be implemented to allow organisations to identify all personal information collected by and for the ***SMI Landscape***. The PIA should be used to address any privacy risks with a new project and to mitigate those risks.

4.1.4 Minimise the data collected such that only personal information necessary to operate and maintain the infrastructure or deliver customer service is collected.

4.1.5 Where ever possible ensure data is de-identified by putting protections in place so that identifying information is only available to those authorised.

4.1.6 Systems should be carefully designed to store data in such a way that usage information is held separately to identifying information. Linking of smart infrastructure data with a location or customer account information shall only be allowed when required for billing, service restoration, or other operational needs.

4.1.7 Organisations shall provide access controls around personal and identifying information. Access controls shall be supported by audit trails so personal information is accessed appropriately.

4.1.8 Provide a mechanism to ensure technology and business processes are robust and compliance requirements are being met.

4.1.9 The roll out of smart infrastructure should be accompanied by community awareness initiatives and notices (Privacy Statement) about the types of information collected using smart infrastructure and how that information will be used.

4.2 Risk Assessment

4.2.1 SMI communications and data security shall be addressed using a risk based approach.

4.2.2 All transactions shall be between mutually authenticated parties using methods identified by a risk based model.

4.2.3 All communications performed both locally and remotely with the meter shall occur in a secure manner.

4.2.4 During the planning process for the procurement, deployment and maintenance of ***SMI Landscape*** systems, a risk assessment shall be completed. The assessment shall be conducted in accordance with AS31000, AS27001 and AS27002.

4.2.5 The communications and data security risk assessment shall include considerations of possible vulnerabilities of the ***SMI Landscape***.

4.2.6 The risk assessment shall be reviewed periodically, considering the time since the last assessment and any significant changes .

4.3 Authority Registers

For the purpose of this document the Authority Register is intended to automatically control data and service transactions so that only permissible data and services complete. The authority register is a technical control function managed by the ***Facilitating Party*** of the data flow and/or service.

4.3.1 As the ***Facilitating Party***, the Local Network Service Provider (LNSP) shall maintain a register of authorised parties, devices and service agreements facilitated via the LNSP.

4.3.2 Where a service is provided without LNSP facilitation, the service provider shall maintain a register of authorised parties, devices and service agreements.

4.3.3 The authority registers shall be utilised to control service requests (see Table 3.3).

4.4 Verification

4.4.1 A trust relationship needs to be established and maintained between the service provider, customer and facilitating parties.

4.4.2 The service provider shall use identifying credentials (such as ‘100 point test’, digital certificates; secrets; NMI) to verify parties and establish a trust relationship.

4.4.3 A service provider shall use and maintain secrets of their trusted relationships eg user names/passwords.

4.4.4 A trust relationship needs to be dropped or re-established upon the change of a party’s circumstances e.g. customer move out.

4.5 Utility HAN Principles

4.5.1 The ESI Implementation is the demarcation point between the customer domain and the SMI domain (see figure 2.1). This is the boundary of security control at the consumer edge of the SMI Landscape.

4.5.2 The ESI implementation shall facilitate authorised service delivery while preventing unauthorised access.

4.5.3 HAN binding windows shall open a secure binding window only for as long as required to bind the device and only for that device(s). The duration of the binding window shall be set according to the ***Facilitating Party*** as is determined by a risk assessment.

4.5.4 Unbinding of HAN devices shall be completed on request of the customer or authorised party to allow for opt out, termination and suspension of HAN services

4.5.5 Enforced Unbinding of all consumer HAN devices shall be completed when a move out is detected. HAN devices recorded as persistent shall remain bound (eg a HAN connected Water Meter).

4.5.6 The party that binds the device must confirm the requester’s authority to establish the service eg to confirm the customer’s identity with reasonable confidence and the explicit informed consent of the customer.

4.5.7 All devices must be certified by the relevant standards body (eg ZigBee Alliance to meet the ZigBee Smart Energy Profile) and must use production (not test) certificates.

4.5.8 The commencement date of the electricity supply to the customer shall be utilised to enable consumer privacy by blocking requests for any data prior to this date. (This may require a localised ESI Implementation to achieve this privacy requirement).

4.5.9 Security and life cycle management of devices on the utility HAN is the responsibility of the installing party, e.g. a water meter is the responsibility of the water utility; an IHD is the responsibility of the installing Retailer or the customer respectively; a DRED is the responsibility of the installing demand response organisation.

4.5.10 While HAN device discovery is recognised as an available capability of a HAN Device, the use of HAN device discovery information should be limited to supporting and diagnostics purposes only, so that Personal Information cannot be collected nor stored without the customer’s informed consent.

4.5.11 The **Facilitating *Party*** should ensure a regular HAN device Trust Centre back-up is executed and exercised to ensure HAN devices can be restored following a meter exchange without requiring a device re-bind.

4.5.12 Service agreements need to be in place between all parties (implied or explicit)

4.5.13 The ***Facilitating* Party** shall, through its service agreements, understand which devices are to remain bound across a customer move out (eg DRED, water meter). All other bound devices eg IHD shall be automatically unbound on customer move out.

4.5.14 The ***Facilitating Party*** is permitted to un-bind stale HAN devices if a device is inactive for greater than 12 months (or other agreed period) or if the ESI approaches its capacity. eg purging of inactive consumer HAN devices.

4.5.15 The ***Facilitating Party*** is permitted and expected to un-bind any HAN device that it considers represents a reasonable threat to the stability or availability of the Utility HAN or SMI Landscape.

4.6 Smart Meter Physical Ports

4.6.1 All local communications interfaces of the meter are to be secured including optical ports serial ports, USB ports, Ethernet ports, Wireless and equivalent local physical interfaces to the meter irrespective if those ports are normally exposed, or under a cover or seal.

4.7 Energy Portals

The following security controls are recommended guidelines for Energy Portals delivered over public networks like the internet.

4.7.1 Implement a firewall at each Internet connection and between any demilitarized zone (DMZ) and the internal network zone.

4.7.2 Develop configuration standards for web system components. Assure that these standards address all known security vulnerabilities and are consistent with industry-accepted system hardening standards. Sources of industry-accepted system hardening standards may include, but are not limited to:

- Center for Internet Security (CIS)
- International Organization for Standardization (ISO)
- SysAdmin Audit Network Security (SANS) Institute
- National Institute of Standards Technology (NIST)

4.7.3 Develop web applications based on secure coding guidelines (for example, the Open Web Application Security Project (OWASP) Guide, SANS CWE Top 25, CERT Secure Coding Standards or equivalent).

4.7.4 Information involved in online transactions must be protected to prevent incomplete transmission, mis-routing, unauthorized message alteration, unauthorized disclosure, unauthorized message duplication or replay.

4.7.5 Each user should access the web application and system with a unique ID and password.

4.7.6 Enable only necessary and secure services, protocols, daemons, or equivalent, as required for the function of the system and remove all unnecessary services.

4.7.7 Security testing (for example penetration testing, vulnerability scanning, source code review or equivalent) on the web server and its related infrastructure is highly recommended prior to release to production in order to identify and remediate any potential critical vulnerability. Ongoing security testing is recommended on an annual basis and/or after any significant code or web infrastructure changes.

4.7.8 Ensure that all system components and software are protected from known vulnerabilities by having the latest vendor-supplied security patches installed in a timely manner.

4.7.9 Should the web application involve payment card processing, one should investigate further into the requirement of Payment Card Industry (PCI) Data Security Standard (DSS).

4.8 Integrity

4.8.1 Transport of data through the ***SMI Landscape*** shall, by deliberate design, deliver data to ensure consistence and accuracy without adulteration or alteration.

4.8.2 Error Detection and or Error Correction shall be utilised for data transport and storage of data to ensure integrity of data

4.8.3 Encryption ciphers shall utilise keys to encode all data transport across unsecured communication networks or network segments.

4.8.4 Processing and transformation of data shall maintain data fidelity consistent for accurate presentation (multipliers, rounding and truncation)

4.9 Management of Identified Breaches/Events

Unauthorised access attempts include anything from exploration to hacking in order to gain access to information. Unauthorised access also includes gaining access to computer systems, meters and communication equipment.

4.9.1 To manage security breaches all systems and infrastructure must have appropriate logging, intrusion detection systems and policies in place.

4.9.2 If a breach is identified, appropriate people must be informed in a timely manner. An authorised person should undertake remedial action to the level of their authorisation. Any action should aim to isolate systems from non-affected systems to mitigate loss, damage or propagation.

4.9.3 Escalate the matter internally as appropriate, including informing the persons responsible for privacy compliance. Law enforcement agencies may also need to be contacted. Individuals affected (i.e. customers) may also need to be notified.

4.9.4 Once the immediate steps are taken to mitigate the risks associated with the breach, the cause of the breach should be investigated and evaluation of the existing prevention plan should be considered. A prevention plan should suggest actions which are proportionate to the significance of the breach and whether it was a systemic breach or an isolated instance.

4.9.5 Routine examinations of security logs and investigation into all unusual events should be part of BAU processes.

4.9.6 All unauthorised access attempts must be noted and logged. The Audit Trail/System Access Log must be reviewed regularly, exception reports generated and inspected and appropriate action taken.

4.10 Smart Meter Infrastructure availability

4.10.1 A variety of technologies (i.e. boundary protection devices or equivalent) should be implemented to reduce the effects of malicious attacks such as denial of service, virus/worm propagation or equivalent.

4.10.2 Capacity and performance management demands should be monitored and projections of future capacity requirements made to ensure that adequate capacity is available.

4.10.3 Network equipment should be protected to reduce the risks from environmental threats, hazards, and opportunities for unauthorized access.

4.10.4 In order to protect the SMI network availability, rates and volume of transactions should be managed to protect SMI systems.

4.11 Interception capability

Smart Meter Infrastructure provided by an LNSP may operate over a private communications infrastructure which may be exempt from the Telecommunications Act (1997). An LNSP exempt communications network including SMI can only be used for:

(i) Managing the generation, transmission, distribution or supply of electricity; or

(ii) Charging for the supply of electricity.

Therefore use of an SMI to deliver commercial messaging would invalidate the LNSP exempt network status.

4.11.1 All traffic and services carried by the SMI communications network shall be expressly limited to those that relate to the supply of energy or other exempt purposes. For example HAN text messaging shall not be used for cross promotion of services outside the energy sector however other exempt services would be permitted.

4.11.2 Should an SMI communications network carry commercial traffic the party facilitating the service would be expected to hold a carrier licence or be providing the service to a party that holds a carrier licence

4.11.3 A facilitating party permitting carriage of 3rd party traffic may require an Interception Capability to allow for auditing, inspection and compliance related activities

4.12 Bilateral interfaces

4.12.1 Interfaces over public networks should be encrypted and all parties identified by digital certificates

4.12.2 Interfaces over private networks or intranets should follow a risk based assessment and design regarding encryption and certificates

4.12.3 ***Facilitated Access*** such as via Application Programming Interface (API) shall be secured using two-way (mutual) certificate based SSL authentication. Mutual authentication provides trust of both the client and the server's identity.

4.12.4 Retailers or 3rd Parties must provide the ***Facilitating Party*** with the Common Name (CN) from their public key where the X509 certificate is signed by a supported Certificate Authority (CA), like Verisign, Thawte, Globalsign, Comodo or equivalent in order to use the ***Facilitated Access*** API or equivalent.

4.12.5 Each participant and 3rd party must use reasonable endeavours to make that portion of the National B2B Infrastructure over which they have control and for which they are responsible available at all times.

4.13 Certificate Management

Digital Certificate management requires a trusted signing authority. The signing authority is usually the root Certificate Authority (CA) or a derivative of the root CA. Certificates are effectively secrets that have a lifecycle and need to be managed through their lifecycle (birth to death). Principles of Certificate management include but are not limited to;

4.13.1 The root Certificate Authority (CA) is based in Australia. For example AEMO provide a root certificate authority for Gas market participants and this service could be extended to provide a CA service for electricity market participants.

4.13.2 The Certificate Authority register subscribers admitted to the system, verifying the bona fides of those subscribers.

4.13.3 The Certificate Authority delivers and maintains a secure CA root certificate for verification of certificates derived from the root certificate.

4.13.4 The root CA delivers trusted digital certificates to all Subscribers including certificate renewals.

4.13.5 The Certificate Authority will revoke and re-issue digital certificates to Subscribers as appropriate, for instance if certificates are compromise

4.13.6 In the event of digital certificate revocation of a Subscriber by the Certificate Authority, other subscribers will not be affected.

4.13.7 The CA will keep details of Subscribers' digital certification confidential.

Appendix A. Glossary

Application Programmable Interface (API)

Application Programming Interface means the technical interface that permits two disparate systems to exchange data or services between in a secure manner and usually between two different businesses. eg Business to Business Application Programming Interface (B2B API) bilaterally agreed between Market Participants and/or 3rd Parties to facilitate secure access to systems and services

commencement date

commencement date means a date set to ensure that *HAN Devices* cannot access historical data stored in *meters* or the *ESI* before the specified date.

controlled load contactor (CLC)

controlled load contactor means an electrically controlled switch used to control power to a device or devices in the *customer's* premises. Throughout this specification functionality associated with the *controlled load contactor* is also supported on the load control relays.

controlled load contactor and/or relay (CLC/R)

CLC/R refers to the *controlled load contactor* and/or *relay(s)*. Throughout this specification functionality associated with the *controlled load contactor* is also supported by (load control) *relays*.

customer

customer means an end-use retail *energy* customer at a *metering point* that may consume and/or generate electricity

data mirroring

data mirroring means retaining information in the *ESI* from battery powered devices. This functionality is provided to enable battery powered devices to increase the battery life.

denial of service (DoS)

A specific attack on a IS system, where the aim is to make the system unavailable rather than trying to gain access.

distribution network area

distribution network area means d*istribution network service provider's distribution system* under the rules

Distribution Network Service Provider (DNSP)

Distribution Network Service Provider means a person who engages in the activity of owning, controlling or operating a *distribution system.*

distribution system

distribution system means a distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system.

download

download means to extract data from a *meter* to the *SMMS*.

energy

energy means a *supply* or source of electrical power *measured* over time leading to *active* and/or *reactive energy.*

energy data

energy data means *interval energy data* and *accumulated energy data*.

Energy Services Interface (ESI)

Energy Services Interface means a secure interface to a premise's communications network which facilitates relevant energy applications (e.g. remote load control, demand response, monitoring and control of DER, in-premises display of customer usage, reading of energy and non-energy meters, PEV charging and roaming coordination, and integration with energy management systems, etc.), provides auditing / logging functions that record transactions to and from *HAN devices*, and, often, coordination functions that enable secure transactions between the *HAN devices* commissioned and *registered* on its network and enrolled in a service provider program. Note: There may be more than one *ESI* in a premises or more than one *ESI* in a *HAN device*

ESI Implementation

ESI Implementation means the physical implementation of the *ESI* in the scope of this specification. It includes all the functionality of the *ESI* (as described in the ZigBee Smart Energy Profile Application Layer) and additional functionality requirements, including transmit power and receive sensitivity and provides storage requirements for some items.

event

event means something of significance has occurred

export

export means the delivery of *energy* from the National Electricity Market Pool to a *customer*.

Facilitated Access

Facilitated Access means the provision of a service or access to systems for another party so that they in turn can provide a service or access data for a system or infrastructure assets not under their own control.

Facilitating Party

Facilitating Party means the entity owning and or operating components of the SMI for which ***Facilitated Access*** is provided to enable a service or data provision.

Home Area Network (HAN)

Home Area Network means a Local Area Network (LAN) established within the *customer* premises.

HAN device

HAN device means equipment fitted with a communications modem capable of communicating with the *HAN*.

HAN interface

HAN interface means an interface supporting communications between the *meter* and *HAN Devices*.

instruction

instruction means either a message or a command sent to a *meter* or *HAN devices*

interface standard

interface standard means a non-proprietary standard that describes one or more functional and/or physical characteristics necessary to allow the exchange of information between two or more (usually different) systems or pieces of equipment.

interval energy data

interval energy data means the *interval energy channels stored* by a *meter.*

interval energy value

interval energy value means the value resulting from the *measurement* representing a flow of *energy* at a *metering point* over a *trading interval* or are sub-multiples of a *trading interval.*

load control scheme

load control scheme means a sequence of load control switch *instructions* capable of switching the *controlled load contactor* or relay(s) at specified times during the day.

Load Cycling

Load Cycling means a repetitive sequence of turn off and turn on durations

load switch action

load switch action means an instruction to be performed by the *controlled load contactor* integrated into the *meter*.

local

local means operations performed locally at the *meter* and not performed using the *SMCN*.

local time

local time means the time and date that a customer would refer to. Local time and date is obtained when the *ESI* applies a programmable offset from the *meter time* and date.

measure

measure means the process of obtaining the magnitude of a quantity

meter

meter means a device complying with *Australian Standards* which *measures* and *records* the flow of electrical *energy*.

meter loss of supply

meter loss of supply means

- For single phase meters: the *voltage* falls below that specified at the lower end of extended operating range as detailed in AS62056.11.
- For three phase meters: the *voltage* on all phases falls below that specified at the lower end of the extended operating range as detailed in AS62056.11.

metering data

metering data means the data obtained from a *metering installation*, the processed data or substituted data.

metering installation

metering installation means the assembly of components and/or processes that are controlled for the purpose of metrology and which lie between the *metering point(s)* or non-*metered connection point* and the point of connection to the tele*communications network*. The assembly of components may include the combination of several *metering points* to derive the *metering data* for a *connection point*. The *metering installation* must be classified as a revenue *metering installation* and/or a check *metering installation*.

metering point

> ***metering point*** means the point of physical connection of the device *measuring* the electrical power in the power conductor.

Priority Override

> ***Priority Override*** describes a separate command sent to *CLC/Rs* contained in the *meter*

record

> ***record*** means to capture the value. For values which are *recorded* it is only possible to obtain a single value (see *stored* when multiple values must be retained)

registered

> ***registered*** refers to a *HAN device* which has successfully performed *registration*

registration

> ***registration*** means the process by which a *HAN Device* is authorized to communicate on a logical network. This involves the exchange of security credentials with an *ESI*. The *registration* process is required for the exchange of secure information between a *registered* device and the *ESI* and among other *HAN devices registered* to that *ESI*.

relay

> ***relay*** means an electrically controlled switch within a *meter*, that is used to break or restore continuity in a circuit allowing the control of a device

report

> ***report*** means to send a message that informs the receiving party of an *event*.

remote

> ***Remote*** means operations performed using the *SMCN* to access the *meter* or data held in the *meter*.

request

> ***request*** means the process by which commands are sent to the *meter* by the *SMMS*.

secure

> ***secure*** means in a manner that prevents an unauthorised access to or interference with the operation of the *SMI*.

smart meter

> ***smart meter*** means a device complying with *Australian Standards* which *measures* and *records* the production and/or consumption of electrical *energy* and also conforms to the minimum functionality requirements.

Smart Meter Communications Network (SMCN)

> ***SMCN*** means all communications equipment, processes and arrangements that enable *remote* communications between the *meter* and the *SMMS.*

SMI (Smart Metering Infrastructure)

> ***SMI*** means the infrastructure associated with the installation and operation of *smart meters,* including the *meters*, *SMCN* and *SMMS*.

Smart Meter Management System (SMMS)

> ***Smart Meter Management System*** means the component of an *SMI system* that allows commands and messages to be exchanged with the *smart meter* via the *SMCN*.

supply

supply means the delivery of electricity.

supply contactor

supply contactor means an electrically controlled switch that enables the *supply* to be turned off or turned on.

transmission

transmission means to send a signal. In the context of the *HAN* transmissions are sent by radio or power-line.

utility HAN

utility HAN refers to to the *HAN* containing the utility *ESI* and the *HAN devices registered* on that *ESI.*