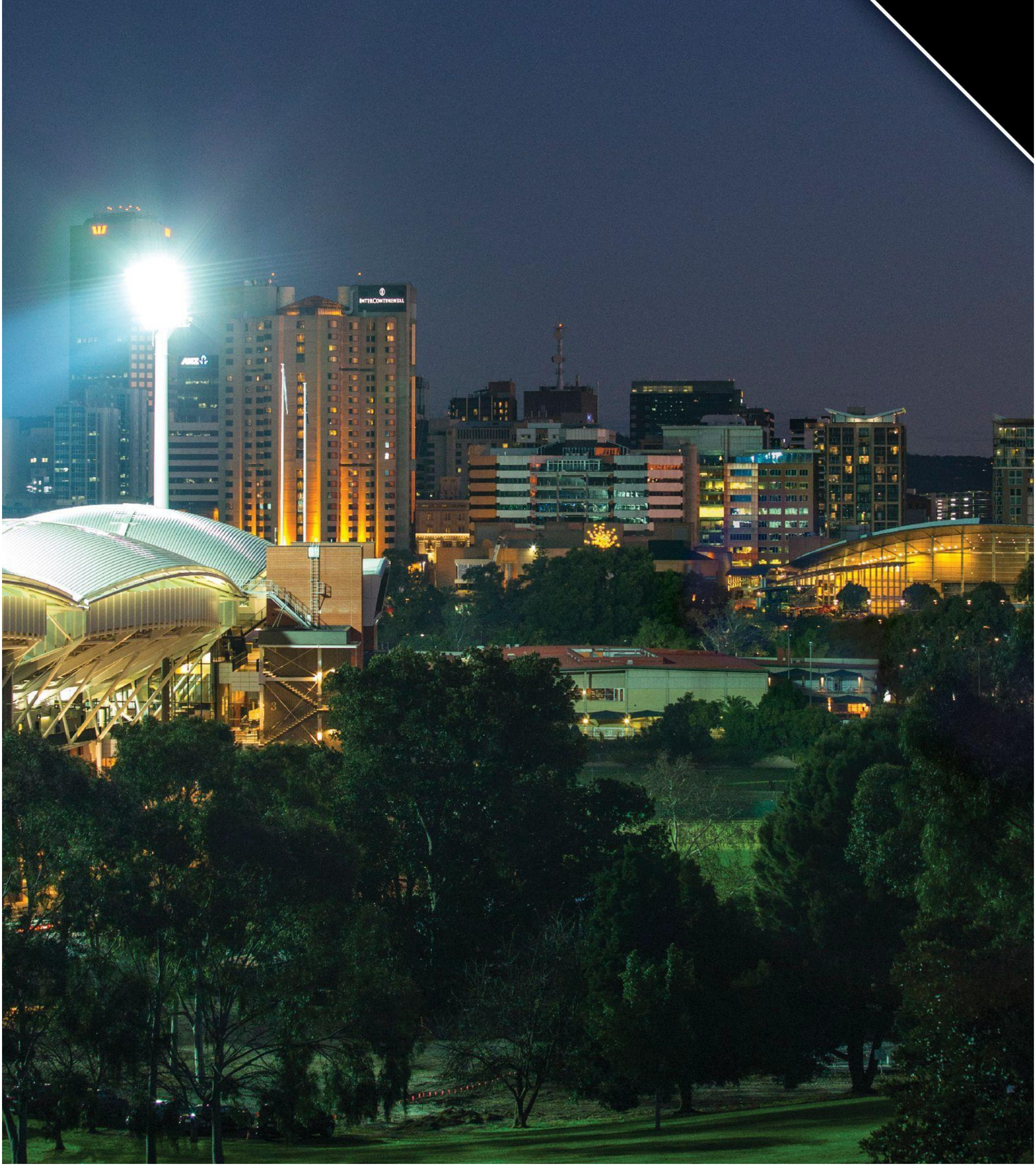
Attachment 14.3

SA Power Networks:
Tariff and Metering Business Case

September 2014



Tariff and metering business case

Version 1.0, 22nd September 2014

SA Power Networks

www.sapowernetworks.com.au

SIGNATURES

The following Stakeholders have reviewed and accepted the details within this document. Any changes to the document may only be made with the formal agreement of the signatories.

General Manager Network Management Doug Schmidt	Signature .... Date 23/9/2014
General Manager Corporate Strategy Sean Kelly	Signature Sean M Kelly Date 23/9/2014.
General Manager Customer Relations Sonya Furey	Signature .... Date 22/9/14
Chief Information Officer Chris Ford	Signature .... Date 23/9/14
Manager Network Investment Strategy and Planning Mark Vincent	Signature .... Date 22/9/14.

EXECUTIVE SUMMARY

SA Power Networks' customers are no longer passive consumers of energy supplied by the grid. They are increasingly taking advantage of new opportunities to participate actively in the energy market, through investments in solar generation and more active management of their own energy use. Public policy, exemplified by the proposed reforms arising from the AEMC's 2012 *Power of Choice* review [2], is focused on encouraging and enabling this 'demand-side participation' (DSP) as a means to empower consumers to respond to rising energy costs and improve the economic efficiency of future network investment.

Increasing DSP and emerging technologies such as battery storage and electric vehicles are changing the role of the network from a one-way energy distribution system to an active two-way grid that connects a dynamic web of distributed consumption and generation resources. This creates new challenges in how we manage and operate the network, particularly the low voltage (LV) network. It also means that the way we charge most customers for their use of the network, which is in proportion to the amount of energy they import from the grid, is no longer appropriate. For example, customers with their own generation may place considerable demands on the network at peak times but have low or even negative net import over the course of a year.

We propose to respond to these challenges in the 2015-20 period by:

- commencing a transition to more cost-reflective network tariffs for small market customers
- installing 'smart ready' meters as standard to support these tariffs
- making use of the opportunities created by smarter metering as a cost-efficient platform for monitoring power quality in the LV network and for broader benefits.

A cost-reflective network tariff

From July 2015 we propose to transition small-market customers to a new cost-reflective network tariff based on maximum demand, as follows:

- From July 2015 to July 2017 the tariff will be made available on a limited, predominantly opt-in basis.
- From July 2017 the tariff will be mandatory for all new customers and all customers upgrading their supply arrangements (e.g. to install 3-phase power, solar photovoltaic (PV), etc). Other customers will be able to access the tariff on an opt-in basis.

Our proposed approach transitions customers to a cost-reflective tariff at the time at which they are making new demand-side investment decisions. This will preserve existing customer investments while driving efficient customer behaviour in future. It will also minimise the cost of the new metering required to enable new tariffs, since these customers would require a new meter in any event. We expect to transition around 56,000 customers per annum to the new tariff from July 2017 under this approach, phasing in the tariff progressively over the next two regulatory periods.

Detailed economic modelling commissioned by SA Power Networks [9] indicates that the transition to a cost-reflective network tariff will deliver a number of benefits:

- It will give customers the opportunity to save money by using the network efficiently, placing downward pressure on future peak demand growth by encouraging customers to shift discretionary load outside of peak hours.
- It will drive more efficient demand-side investment choices, increasing utilisation of existing network assets and reducing total cost of energy to the community in the long term.

- It will arrest cross-subsidies that are driving increasing network costs for those customers that do not have their own distributed energy resources (DER). In 2014, we estimate that the total subsidy of PV customers by non-PV customers in South Australia will be around $16 million, and this is growing year-on-year as PV penetration continues to rise.

In order to achieve the necessary transition to cost-reflective tariffs with minimal customer impact, we propose a comprehensive customer and retailer education and engagement program, including additional call centre resources to support customers in understanding the tariff and maximising their benefit.

We also propose to transition all customers from a quarterly to a monthly meter reading cycle from mid 2017. Although the key driver is tariff reform, this is also an enabler for monthly billing based on actual (not estimated) reads, a service valued by customers [38] and strongly supported by consumer groups such as the SA Council of Social Services (SACOSS) [39].

Our proposed approach results from key recommendations of the AEMC *Power of Choice* review [2] and the Productivity Commission [19]. It aligns fully with the AEMC's recent draft determination on the current proposed rule change relating to future distribution network pricing [46], which proposes:

- Networks should phase in cost-reflective tariffs, with 2017 proposed as a timeframe for introduction
- Networks will be required to minimise the impacts of price changes on consumers, for example by gradually transitioning to new prices over 5 years or more.

The AEMC estimates that up to 81% of consumers would face lower network charges in the medium term under a cost-reflective capacity price, and finds that capacity pricing is more beneficial than alternatives such as critical peak pricing. This aligns with the findings of our own research.

Smarter meters as a tool to manage the two-way grid

We propose both to facilitate a transition to smarter metering in South Australia from 2015 onwards, and to position to unlock the benefits that smarter meters can offer, by:

- moving to an interval meter as our standard meter for regulated metering services, required to enable new capacity tariffs, that is also upgradable or 'smart ready'
- establishing IT systems, business processes and market gateway interfaces required to enable operational benefits from smart meters, including smart meters deployed by third parties under a market-led rollout (via the proposed AEMO market gateway)
- enabling telecommunications on a targeted subset of our own 'smart ready' meters to establish a core capability in network monitoring across specific areas of the LV network.

The primary benefit we are seeking is to establish a capability to actively monitor power quality within the LV network, where we have almost no monitoring today. As solar PV penetration grows, the grid becomes increasingly characterised by two-way energy flows at the LV network level, and current approaches to voltage regulation are no longer sufficient.

A study by consultants PSC found that across older areas of the LV network, existing network infrastructure and voltage regulation approaches limit acceptable solar PV penetration to around 25% of customers [25]. Solar PV penetration is already reaching this level in some areas, and is forecast to continue to grow in South Australia, rising to 40% of premises by 2020 and more than 50% by 2025 [9]. If we are to continue to accommodate solar PV and other distributed energy resources connected at the LV network while maintaining power quality at the customer supply point to Australian standards, we urgently require the capability to actively monitor voltage in the LV network.

Our proposed approach is to enable three 3-phase meters for voltage monitoring per LV circuit in target areas. This will achieve the capability we require for a total cost (CAPEX and OPEX, 15 year NPV) that is 50%-60% of the cost of an alternative grid-side solution.

As well as power quality monitoring, we propose to enable a range of other benefits from smart meters, drawing on experience in Victoria, including outage notification, remote testing, load control and others. These benefits will accrue predominantly in the medium- to long-term as the penetration of smart meters in South Australia grows under a market-led meter rollout.

Based on the most recent studies by Deloitte [21] and Energeia [27], the future value of these benefits in South Australia (15 year NPV) is estimated at between $21 million and $180 million, depending on the rate of uptake of smart meters in a market-led rollout. In addition, we estimate a further $3-4 million in future benefits from the small subset of meters enabled with communications under our targeted power quality monitoring program.

Timeline

A high-level timeline for the initiatives set out in this business case is shown in Figure 1 below.

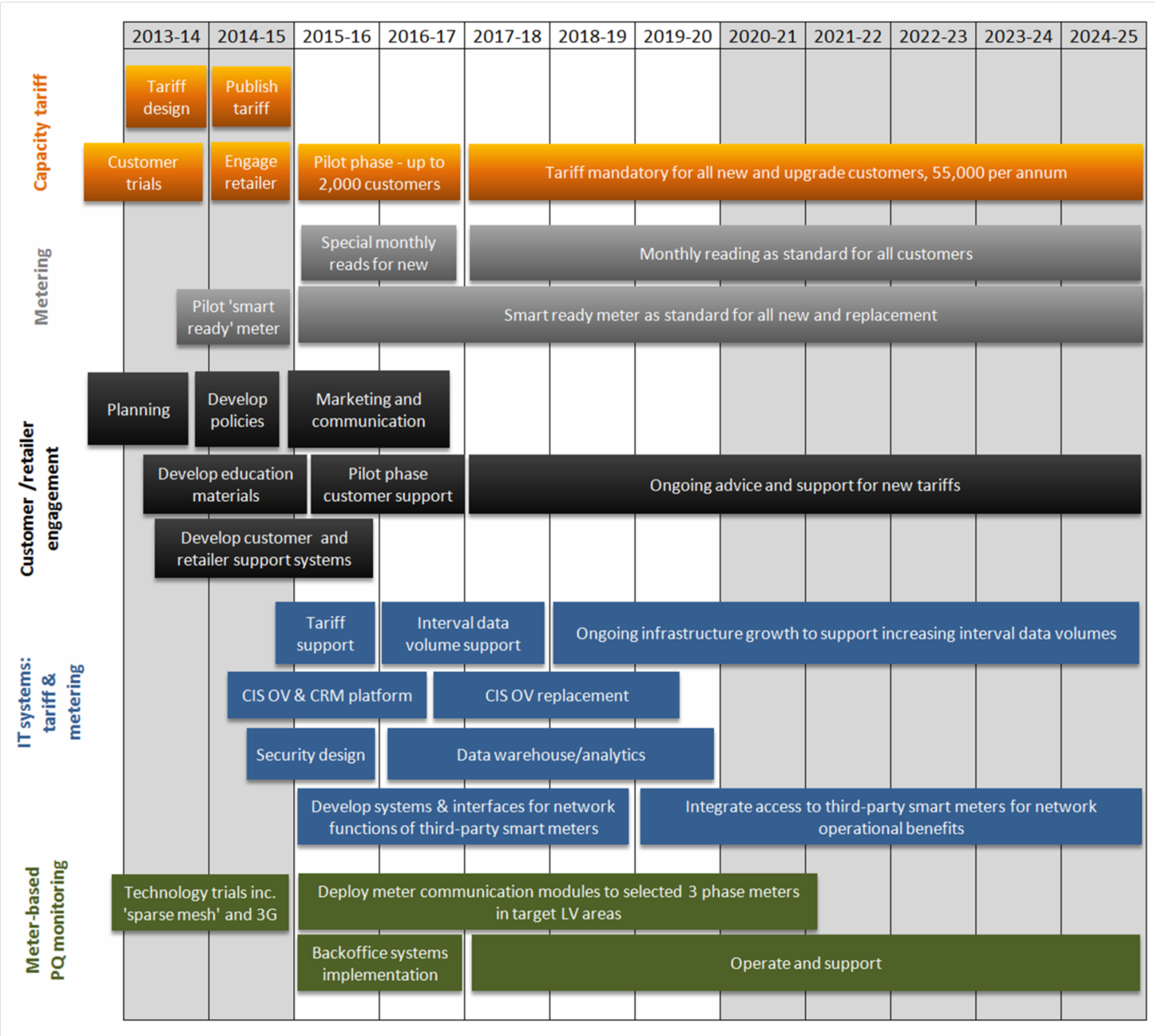


Figure 1 - Timeline

Costs

Our proposed tariff and metering program has the following cost components in the 2015-20 period:

- **new meters that can support our tariff,** phased in through our 'new and replacement' approach to tariff introduction
- **monthly meter reading** for all customers from July 2017
- **new IT systems** to enable the tariff, and to process the increased volumes of data from smarter meters, both those we install and those that third parties install that we access through the market gateway
- **customer and retailer engagement** to support customers through the transition to our new network tariff
- **telecommunications modules and associated systems** for a subset of the meters we install, to enable power quality monitoring and other operational benefits.

The total incremental CAPEX for 2015-20 is shown in Table 1 below and the chart that follows. The table also shows the indicative allocation of costs to Standard Control Services (S) and Alternative Control Services (A).

CAPEX	Cost ($M)	SCS/ ACS	2015-16	2016-17	2017-18	2018-19	2019-20
Base IT systems - tariff & contestability	20.1	S/A	1.7	1.8	9.7	5.1	1.9
Customer/retailer engagement & tariff implementation	5.8	S	3.1	2.	0.0	0.	0.0
Meter communications IT svstems	9.0	S	5.0	2.	1.1	0.	0.3
Meters - smart ready, new and upgrade	13.4	A	2.7	2.	2.9	3.	1.9
Meters - comms modules	11.7	S	2.3	2.	2.3	2.	2.3
Total	**59.9**		**14.9**	**12.2**	**15.9**	**10.5**	**6.5**

Table 1 – CAPEX summary

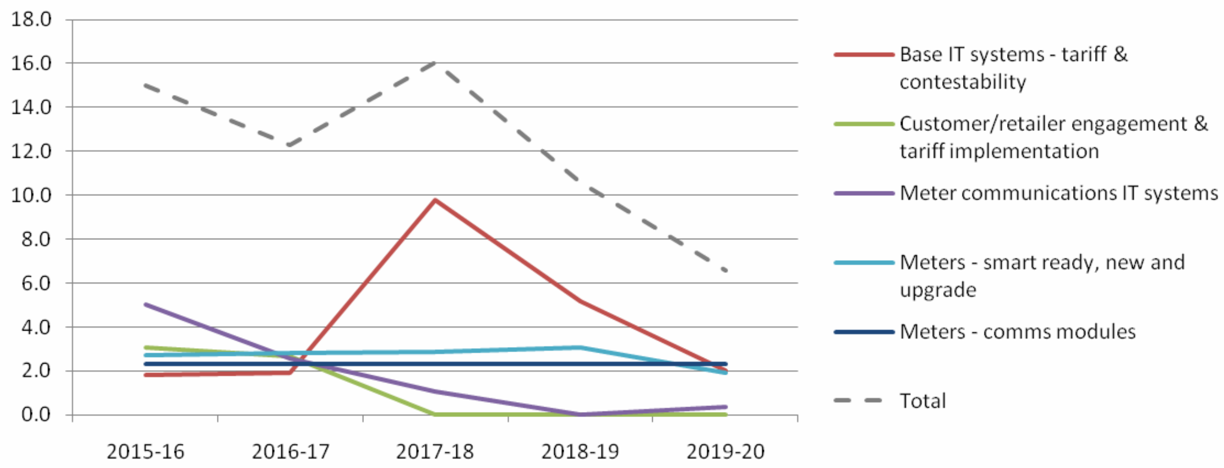


Figure 2 – CAPEX spending profile

Table 2 and the following chart show the total impact on operating cost for the 2015-20 period. The indicative allocation of operating costs to Standard Control Services (SCS) and Alternative Control Services (ACS) is also shown.

OPEX	Cost ($M)	SCS/ ACS	2015-16	2016-17	2017-18	2018-19	2019-20
Base IT systems - tariff & contestability	3.7	S	0.0	0.5	0.9	1.1	1.2
Customer/retailer engagement & tariff implementation	11.9	S	0.0	1.6	3.2	3.5	3.6
Meter communications IT systems	7.0	S	0.8	1.1	1.3	1.7	2.1
Meters - meter reading / data processing	36.4	A/S	0.1	0.2	11.7	12.0	12.4
Meters - comms modules - communications	5.4	S	0.4	0.7	1.1	1.4	1.8
Total	**64.4**		**1.3**	**4.0**	**18.1**	**19.8**	**21.2**

Table 2 – OPEX summary

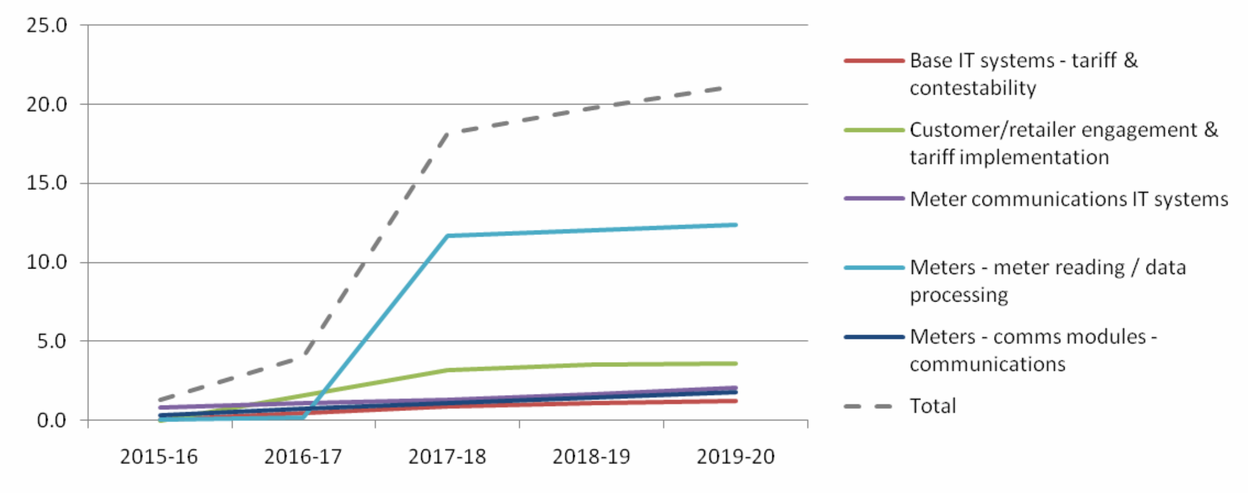


Figure 3 – OPEX spending profile

Full details of these costs are contained in the body of this document.

Summary

There is an overwhelming consensus in Australia and overseas that cost-reflective network pricing is required as an enabler for increased demand-side participation and to contain rising network costs.

This business case sets out our approach to transitioning customers to capacity-based pricing in a way that minimises customer impact without constraining future benefits, while also minimising the cost of the new metering required.

In addition, we propose to use smarter meters to establish voltage monitoring at the LV network level, a key requirement to enable the future two-way grid, in a more cost-effective way than grid-side alternatives. We will also establish the IT systems necessary to enable the long term network benefits that COAG and AEMC are seeking from a market-led smart meter rollout as the population of smart meters grows in coming years.

Our proposed approach aligns with customer priorities and government policy objectives:

- It aligns fully with the AEMC's draft determination on the current proposed rule change relating to future distribution network pricing [46].
- It addresses customers' priorities expressed through our 2013 *TalkingPower*™ stakeholder consultation program [29], in particular customer insights #10 – #13:

  #10 Consider installing advanced meters

  #11 Continue upgrades to support a two-way network.

  #12 Develop cost-reflective pricing tariffs.

  #13 Educate customers about new technology and industry change to help increase their satisfaction.

- It addresses the needs of the South Australian business community. In a survey of members prior to the last State election, Business SA found that *"80% of respondents supported a rollout of smart meters"* while noting that *"it will be critical that the transition to smart meters is managed to minimise any additional cost on business, particularly small business."* [44].
- It also aligns with the SA Government's proposed 'new and replacement' policy for advanced metering [6], and the objectives of a market-led smart meter rollout.

Finally, the overarching principles that have guided our proposed approach are the National Electricity Market network expenditure objectives [42], in particular:

1. **Meet or manage the expected demand for regulated services over the regulatory control period**

   Cost-reflective tariffs are key to managing future demand growth.

2. **Comply with all applicable regulatory obligations or requirements associated with the provision of regulated services**

   We have a regulated requirement to maintain power quality at the customer supply point to Australian standards.

and the associated expenditure criteria:

1. **The efficient costs of achieving the objectives**

   Through our proposed 'new and upgrade' approach to phasing in new tariffs and new meters we are seeking to achieve our objectives in tariff reform and LV network monitoring as cost-efficiently as possible.

   From a system-wide perspective, aligning network pricing to cost will drive more efficient use of network assets, minimising network cost in the long term.

2. **The costs that a prudent operator would require to achieve the objectives**

   We consider that the initiatives proposed in this business case are the minimum reasonably required by a prudent operator to meet the needs of customers in the 2015-20 period and beyond. Taking into account the information we have today we consider that it would be *imprudent* to:

   - fail to respond to rising network prices and decreasing network utilisation caused by inappropriate price signals in our current tariffs
   - fail to act to mitigate the predicted emergence of widespread power quality issues as solar PV penetration exceeds the limits of current infrastructure on feeders across all older areas of the LV network

- continue to install obsolete and non-upgradable accumulation meters that cannot support new tariffs or provide the data customers need to understand and manage their energy use.

3. **A realistic expectation of demand and cost inputs required to achieve the objectives**

   We have engaged appropriately qualified and experienced industry consultants including Energeia, Deloitte, PSC, Ernst and Young, BIS Shrapnel, UMR and others in order to develop the demand and cost inputs to this business case.

Full details of our proposed tariff and metering initiatives are contained in the body of the business case.

TABLE OF CONTENTS

CHANGE HISTORY

Version	Date	Author	Comments
0.79a	19/5/14	BW	Draft issued to key stakeholders for internal review.
0.9	14/7/14	BW	Revised draft. Issued to key stakeholders and smart grid steering committee for review.
0.94	9/9/14	BW	Final draft, inc. executive summary, issued for sign-off
1.0	22/9/14	BW	Issued

1 INTRODUCTION

1.1 Background

SA Power Networks' customers are no longer passive consumers of energy supplied by the grid. They are, increasingly, taking advantage of new opportunities to participate actively in the energy market, through investments in solar generation and more active management of their own energy use. Public policy, exemplified by the proposed reforms arising from the AEMC's 2012 Power of Choice review [2], is focused on encouraging and enabling this 'demand-side participation' (DSP) as a means to empower consumers to respond to rising energy costs.

A key enabler for more widespread demand-side participation is network tariff reform. For the majority of South Australian customers today, network tariffs are levied on the total amount of energy imported from the grid[1]. These tariffs encourage energy-efficiency overall, but do not provide any incentive for consumers to reduce their peak demand, which is a key driver of network cost. This has led over time to inefficient use of the network and inequitable distribution of network costs, with some consumers paying more in network charges than they should, and some less. As solar PV penetration continues to increase and consumers begin to adopt new technologies such as electric vehicles and battery storage, these issues are increasing.

For these reasons, a key strategic goal for SA Power Networks for the 2015-20 period is to commence a transition to more cost-reflective network tariffs across our customer base. This will position SA Power Networks for a distributed energy future, where our role will continue to shift from distributing energy from centralised generation to a network that enables two-way energy flows between distributed energy resources.

The transition to the more advanced metering required to enable new tariffs also has the potential to significantly enhance SA Power Networks' capability to monitor and manage power quality at the customer premises. This will be key to enabling ongoing integration of new distributed energy resources, as well as creating new opportunities to achieve operational efficiencies and improve customer service levels.

1.2 Purpose

The purpose of this document is to set out the business case for a program of investment that will enable SA Power Networks to transition to cost reflective tariffs and prepare for increased DSP over the 2015 – 2020 regulatory control period.

1.3 Scope

SA Power Networks' overall DSP strategy comprises three elements:

- tariff reform, and the more advanced metering required to enable it
- customer and retailer engagement and support
- future control of discretionary loads to manage local network constraints.

This business case considers the first two elements of this strategy. The third element is addressed in a separate document, the *Flexible Load Strategy* [1].

[1] With the exception of some tariffs specifically tailored to larger business, commercial and industrial customer segments.

This business case is specifically concerned with:

- achieving the progressive, timely introduction of new, more cost-reflective network tariffs for residential and small business customers
- facilitating the transition to the more advanced metering required to support the new tariffs
- educating and supporting customers to enable them to respond effectively to the new tariffs to help them to reduce their energy costs in the long term, and supporting retailers, special interest groups and other industry partners
- implementing the systems required to enable network benefits from advanced meters, in particular in monitoring power quality at the customer supply point
- updating IT systems and business processes to prepare for increasing installation of advanced metering in South Australia by third-parties during the 2015-20 period.

1.4 Related initiatives and strategic alignment

This business case builds on and aligns with a number of related initiatives, including:

- The *Customer Service Strategy* [40]
- The Customer Information System (CIS/OV) and Customer Relationship Management (CRM) systems replacement business case [40]
- The *Customer & Retailer Engagement Strategy – Demand Side Participation (DSP)* [12]
- The 2015-20 *Capacity plan: Quality of Supply, Low Voltage and SWER Network* [17]
- The *Smarter network strategy 2014-20205* [18]

These interdependencies are described in detail in the relevant sections in the body of the document.

The initiatives proposed herein also align with broader corporate strategic objectives, identified customer priorities, state and federal government policy and the National Electricity Market network expenditure objectives, as set out in Section 9.

2 THE CASE FOR CHANGE

The operating environment for network businesses over the next ten years will be highly dynamic and there will need to be material changes in the way the network is constructed and maintained, and in consumer price structures.

SA Power Networks will be required to undertake a significant investment in new devices, information systems and business processes:

- to enable cost-reflective pricing to be implemented to improve overall efficiency of investment by customers and businesses and to prevent further cross-subsidies
- to enable two-way flows of energy across the network
- to manage and extract value from the increased volumes of data arising from advanced metering
- to utilise new digital capabilities to manage network operation, with a particular focus on quality of supply.

The following sections set out the key factors driving these changes in more detail.

2.1 The need for tariff reform

It has been understood for many years that network tariffs based on energy ($/kWh) pricing are not cost-reflective, since network investment is driven largely by peak demand and not total energy use. SA Power Networks began offering more cost-reflective demand-based tariffs to large commercial and industrial customers on an opt-in basis in 1999, and in 2010 made tariffs based on agreed maximum demand mandatory for business customers with maximum demand greater than 100A or 75kVA. The residential and small business segments, which represent the majority of customers, have so far remained on inclining-block tariffs (IBT), in part because those customers do not have meters capable of measuring peak demand.

With no price incentive to use the network efficiently, small-market customers have, in the last ten years, made investment decisions that have led to reduced network utilisation, putting upward pressure on network costs. Today's price structures have also given rise to undesirable cross-subsidies between customers, favouring those that have high peak demand but relatively low overall consumption. These issues have grown in significance through two significant waves of consumer investment, first in air conditioning and more recently in solar generation.

2.1.1 Air conditioning

From 1995 to 2010 there was a very significant community investment in air conditioning in South Australia, driven by falling appliance prices and high summer temperatures. Today South Australia has the highest penetration of air conditioning of any state, with over 90% of homes being air conditioned, and installed capacity continues to increase as the air-conditioned floor space of homes is increasing.

Although air conditioners place a significant load on the network, South Australia's generally mild weather results in low overall utilisation and thus relatively low total energy use through the year. Because of this, today's tariffs have provided little incentive to consumers to install smaller units or to operate them in a way that reduces the impact on summer peak demand. As a consequence, South Australia now has the 'peakiest' demand of any jurisdiction in the National Electricity Market (NEM). The highest 20% of network capacity is required for only one day a year on average, as shown in the load duration curve below.

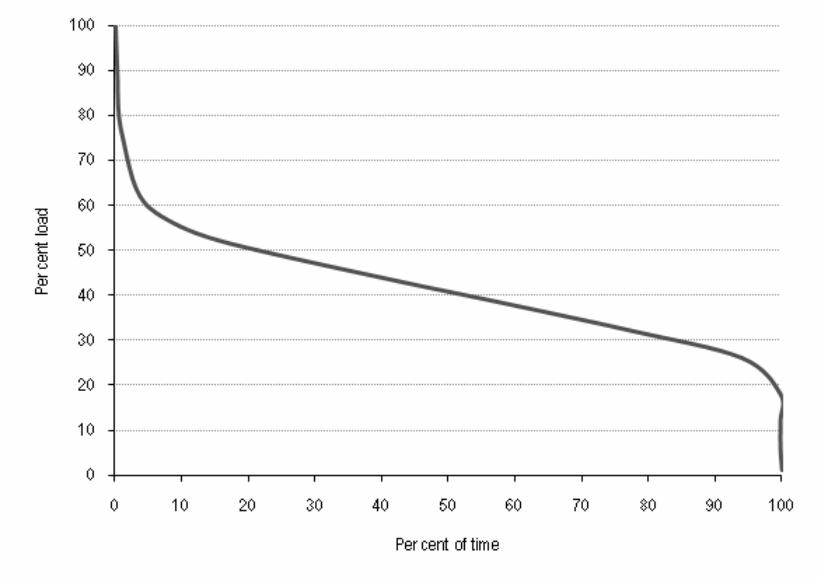


Figure 4 – Load duration curve in South Australia (2012)

It is worth noting that while the last five years have seen an unprecedented flattening in both total demand for energy and peak demand growth, the overall network load factor continues to deteriorate. As households and businesses consume less grid-supplied energy but have no incentive to reduce their peak demand, price per kWh rises in order to recover network costs that are largely fixed.

2.1.2 Solar generation

Since 2010 there has been widespread uptake of small-scale residential solar photo-voltaic (PV) generation, driven by Government incentives and the dramatic decline in the cost of solar PV systems. South Australia now has the highest penetration of domestic rooftop solar PV of any of the NEM regions, and this continues to rise, as shown in Figure 5 below. As of June 2014, more than 22% of residential customers have solar PV installed. The total installed solar capacity across the state is 587 MW – enough to offset the state's entire residential demand on a mild sunny day.

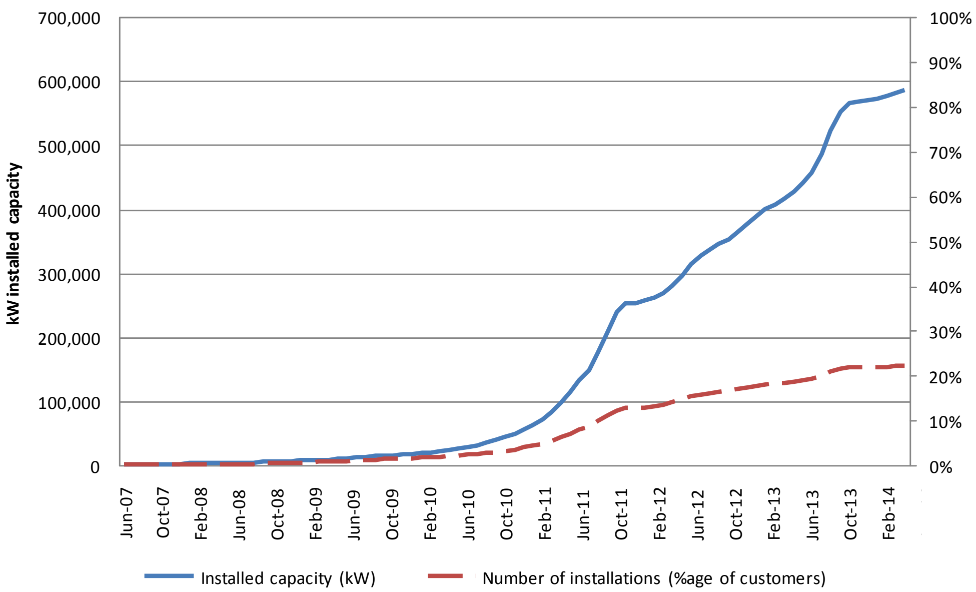


Figure 5 - Installed PV capacity in South Australia

Today's tariffs give rise to significant cross-subsidies from those that don't have solar PV to those that do. Customers with large systems are able to reduce their energy bills substantially (or completely), reducing their contribution to the cost to maintain and operate the distribution network, which is increasingly borne by those without solar, who face rising energy prices as a consequence. In 2014, we estimate that the total subsidy of PV customers by non-PV customers in South Australia will be around $16 million.

This transfer of network costs is inequitable because solar PV customers still generally rely on the distribution network in order to deliver energy that cannot be provided by their own systems, e.g. at night, in winter, or at peak times in summer when their demand exceeds the capacity of their solar system. They also rely on the network to export energy to gain access to feed-in tariffs.

Modelling undertaken for SA Power Networks by consultant Energeia [9] has shown that without tariff reform, the amount of cross-subsidy will continue to grow year-on-year as consumers continue to install solar PV. This is described in more detail in section 3.7.

2.1.3 The future

Solar PV penetration is forecast to continue to grow in South Australia, rising to 40% of premises by 2020 and more than 50% by 2025 [9]. In addition, new demand-side technologies and products are emerging that will drive future waves of consumer investment that may be every bit as significant in their impact on the distribution network as air conditioning and solar PV, including:

- battery storage
- home energy management systems
- electric vehicles.

With the proper price incentives, emerging technologies such as these present opportunities for consumers to flatten their load profiles and thus increase utilisation of, and hence community value from, existing network assets, for example by charging electric vehicles overnight or in the middle of the day when there is an excess of solar capacity, or using battery storage to reserve daytime solar energy for use during the early evening peak in demand.

Conversely, in the absence of cost-reflective network tariffs, consumer adoption of these technologies could drive renewed growth in peak demand and the need for increased network infrastructure augmentation, for example through customers plugging in EVs to charge immediately on returning home from work on summer afternoons when the network is already under stress.

2.1.4 Summary

In summary, network tariffs levied on the basis of energy use are no longer appropriate because they:

- provide weak incentives (at best) for customers to manage their peak demand, which leads to under-utilisation of network assets and higher overall cost to the community
- artificially inflate the value of generation compared to other customer-side investments. In the long term, the overall cost of energy will be minimised when the demand-side market works efficiently and price signals are reflective of underlying cost, so that consumers invest appropriately in a mix of measures that reduce both energy consumed and peak demand
- enable those customers that are able to generate their own energy to avoid some or all of the cost of their network connection, which is passed on to other customers.

This business case is driven primarily by the need to transition to more cost-reflective network tariffs for residential and small-business customers. Without cost reflectivity, the price of electricity will be driven higher by increasingly inefficient use of the network, inefficient consumer investment, and increasing cross-subsidy.

2.2 Demand-side participation and the two-way grid

In recent years there has been a strong focus in public policy on encouraging and enabling customers to participate more actively in the energy market as a means to empower them to respond to rising energy costs. Customers, in turn, have become more engaged; those customers surveyed by SA Power Networks in 2013 through the *TalkingPower*™ consultation program strongly favoured enhancing the network to support the increasing uptake of new customer-side technologies [11]. The next 10 years will see customers:

- continue to install solar, with some potentially taking advantage of new 'zero up-front cost' products where panels are installed and owned by a third party who recovers the cost by selling the generated energy to the customer
- change their behaviour in response to price signals in our new network tariffs, to reduce their peak demand
- be offered new time-of-use retail tariffs, and respond by shifting load to off-peak times
- begin to adopt new demand-side technologies such as battery storage and home energy management systems
- begin to trade demand in the market, potentially through third-party aggregators
- begin to adopt electric vehicles.

These are fundamental changes that will drive an unprecedented shift in the role of the network, from a passive one-way supplier of energy to an active grid that connects a dynamic web of distributed consumption and generation resources, as shown in Figure 6 below.

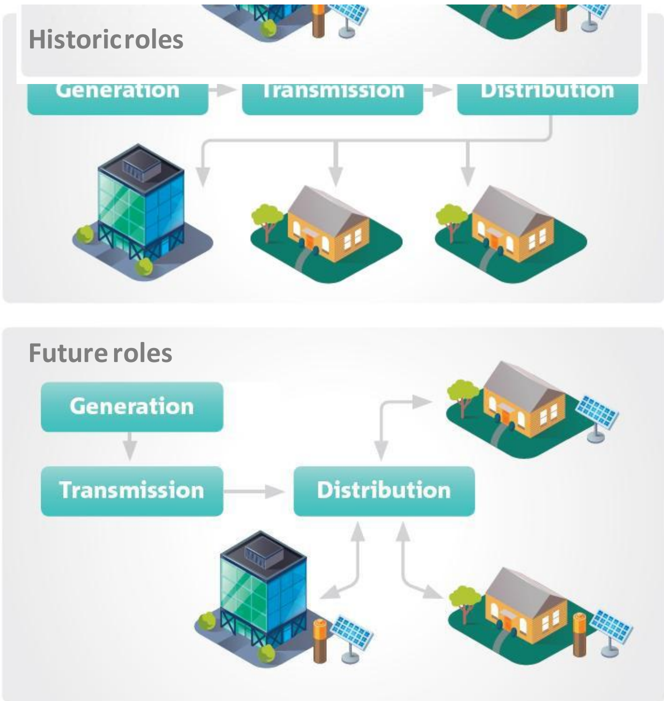


Figure 6 - The evolving role of the distribution network

This transformation will create significant challenges for a network that was designed for the one-way distribution of energy from generator to consumer:

- Consumer load profiles will become more dynamic, challenging the models used today for network planning
- The highly variable two-way power flows in the LV network that result from increasing penetration of residential solar PV and other distributed generation resources will create new challenges for voltage regulation. Modelling undertaken by consultant PSC [25] has shown that the current approach to voltage regulation may not be sufficient to maintain quality of supply at customer premises if solar penetration continues to rise as forecast during the 2015-20 period.

In order to meet these challenges we must adapt the way we monitor and control the network. In particular, we will require a new level of capability to monitor voltage at the LV network level, and increased coordination between LV monitoring and HV voltage regulation, if we are to maintain a reliable supply and continue to meet power quality standards.

2.3 The transition to advanced metering

In order to implement a cost-reflective network tariff for small market customers, a more capable meter is required, as our current type 6 meter cannot measure peak demand. Our future role in the provision of meters for small market customers, however, is currently subject to the outcome of proposed regulatory reforms.

Under the National Electricity Rules (NER) today, SA Power Networks is the monopoly provider of the basic manually-read accumulation meters (type 6 meters) used by ~750,000 residential and small business customers in SA, and the associated meter reading services. The cost of metering is recovered as a regulated metering charge, classified as an Alternative Control Service (ACS). Under a proposed rule change arising from the *Power of Choice* review [2], metering services are to become fully contestable, with the retailer responsible for appointing an accredited provider to provide metering services at market rates and passing the cost on to the consumer.

Associated with the proposed rule change are a number of related proposals for regulatory reform, including the establishment of a national framework for ensuring open access to smart meter functions through common standards, and a proposed mechanism to enable multiple retailers to serve a single customer, with separate billing arrangements (e.g. a customer could buy their 'off peak' and 'on peak' energy from different retailers, sell their excess solar energy to another, and so on).

The *Power of Choice* review also recommended that all new meters should be smart meters. In its response [7] to the *Power of Choice*, the Standing Council on Energy and Resources (SCER[2]) ruled that each state and territory should be free to decide on what minimum specification, if any, should apply for meters installed under the proposed contestable market rules. In January 2014, South Australia's Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE – now renamed to the Department of State Development) released a discussion paper proposing that all new and replacement meters installed under the new rules in SA should, as a minimum, be 'smart ready' type 5 meters, i.e. interval meters that are designed to be upgradable to a full smart meter specification [6].

These proposed reforms are subject to ongoing consultation processes that are expected to run until at least 2015, with final rule changes not expected to come into effect prior to 2016, after which there will be a period of transition to any new arrangements. At the time of

[2] Now the COAG Energy Council

writing, there is, therefore, some considerable uncertainty around the final scope of the rule changes, and the timing of their introduction, but it is clear that:

- the rule changes will not be finalised at the time we submit our regulatory proposal
- the rule changes will come into effect part way through the 2015-20 regulatory period.

This presents a significant challenge in preparing our regulatory proposal in relation to metering for the next period. Our challenge in developing this business case is to propose a ‘no regrets’ approach to metering that:

- will enable customers to be transitioned to cost-reflective network tariffs
- will enable us to continue to offer a basic regulated metering service in the 2015-20 period, a period during which we expect a transition to full contestability in metering services
- represents prudent and efficient investment
- is compatible with the National Electricity Rules as they stand today
- aligns with likely outcomes of the rule change process, and State Government policy direction
- will be compatible with a role as the incumbent Metering Coordinator (MC) in a contestable market should this eventuate.

3 A COST-REFLECTIVE TARIFF

We intend to phase in, over time, cost-reflective network tariffs for residential and small business customers. This will

- encourage efficient consumer investment
- enable a healthy demand-side market
- target peak demand growth
- limit further increase in cross-subsidies.

The sections that follow outline the design of our proposed tariff, the way in which we propose to phase it in, and the associated costs and benefits.

3.1 Tariff design

Network tariffs based on capacity have been in place in South Australia for larger commercial and industrial customers for many years. Our new tariff for small market customers will be tailored to suit residential and small business customer groups.

Considerable work has been undertaken to establish the key principles on which the tariff will be based:

- SA Power Networks has undertaken an analysis [36] of the likely impact on customer behaviour of different tariff structures, comparing capacity-based tariffs against Time of Use (ToU) and Critical Peak Pricing (CPP) tariffs. This has found that the price signal inherent in ToU tariffs is too weak in the South Australian context to deliver material change in customer behaviour during the small number of extreme demand days associated with summer heatwaves. CPP, on the other hand, has the potential to provide a stronger price signal, but has been ruled out after an analysis of historical data suggested that the number of 'critical peak' event days is likely to vary significantly year-on-year due to SA's highly variable summer weather patterns, leading to excessive revenue and bill volatility.
- SA Power Networks engaged consultant Energeia to undertake modelling of the long-term impact on electricity cost of various combinations of network and retail tariffs, taking into account the impact over time of differing price signals on consumer investment strategies and the uptake of different demand-side technologies. This modelling indicates that a network tariff based on capacity (peak demand) yields the most efficient investment outcomes and the lowest energy costs in the long term when compared to inclining block tariffs (IBT) and ToU [9].
- SA Power Networks has undertaken trials with customers in North Adelaide to test customers' ability to understand capacity tariffs [10], as well as broader market research to elicit customer preferences and likely opt-in rates [35].
- We have taken into account the principles put forward in the COAG Energy Council's proposed rule change on distribution network pricing [46], which state that network prices should be *"based on LRMC and determined having regard to their impact on consumers and the additional costs associated with peak demand."*

On the basis of this work, our proposed network tariff for small customers will:

- have a component based on capacity (peak demand), expressed as a dollar price per kW. This will be based on average demand for a 30-minute trading interval, so momentary 'spikes' in demand will not be measured.

- be applied retrospectively based on actual peak demand measured during the previous calendar month; it will not require customers to nominate or be assigned a target level of demand
- vary seasonally, so that the capacity component is higher in the summer months.

Therefore the new tariff requires:

- a meter that enables the peak demand reached in each month to be determined. This will require a more advanced meter than our standard residential type 6 meter, which means that existing customers moving to the new tariff will require a meter replacement. While peak demand will be calculated as the highest average demand in any 30-minute interval during the month, the meter could potentially remain as a type 6 meter in the market.
- monthly billing, with peak demand shown on retailer bill[3]; if customers only receive a bill quarterly they will be less able to correlate their peak demand with their behaviour during the period, and hence will be less able to respond effectively. This aspect of the proposal has significant cost implications, which are detailed in section 3.5.3 below.
- customer and retailer education and support, as customers have become accustomed to saving energy as their primary means to reduce their electricity bill, and do not generally understand how to manage their peak demand to reduce its impact on network costs.

3.2 Tariff introduction strategy

Our goal is to roll out the tariff in a way that maximises benefit and minimises cost. A significant component of the cost associated with introducing the new tariff will be the cost of meter replacement. On the benefit side, the greatest benefits will be realised when the tariff is targeted to customer groups that give rise to inefficiency under the current arrangements.

We have considered the following strategies to phase in the tariff:

1. Make the new tariff mandatory for higher-consumption customers, and allow opt-in for others. This is the approach recommended in the AEMC *Power of Choice* review [2].

   This approach rests on the assumption that high consumption customers also have high peak demand. In practice, there is considerable diversity in customer demand profiles in the residential and small business segment, and annual consumption is not strongly correlated with peak demand [1]. This approach, therefore, would be weakly targeted at best. As it imposes a mandatory change, it will tend to cause customer discontent for those customer groups that are worse off under the new tariff, for limited benefit overall.

2. Offer the new tariff on a purely opt-in basis. This is the position advocated by SCER in its response to the *Power of Choice* review [7].

   This has the benefit that no-one has to take on the new tariff unless they expect to be better off, which will avoid any immediate consumer backlash, but for the same reason it will substantially dilute the benefits. Under this scenario, only 'winners' take up the tariff initially which would, over time, result in increased prices to other customers. This approach relies on the rising tide of prices for those on the old tariff to progressively drive customers to the new tariff over time, but will tend to increase

[3] Strictly speaking it will be up to retailers as to whether and how they reflect the peak demand charge on the customer bill; this aspect will be addressed as part of the customer and retailer engagement strategy.

customer dissatisfaction overall. Such an approach also provides no short term disincentive for customers to install or operate DER in inefficient ways.

3. Make the new tariff mandatory for all new customers and all customers who request a significant change to their metering arrangements, e.g. to install solar or other generation, 3-phase power, etc. Offer the tariff on an opt-in basis for others. This is our proposed approach.

Our proposed 'new and replacement with opt-in' tariff rollout has the following benefits:

- It will minimise the cost of the change in metering required to support the tariff, since the tariff is only introduced to premises where a new meter needs to be installed in any event. Hence the cost is limited to the incremental cost of the more advanced meter compared to a basic type 6 meter.
- It effectively targets customers at the critical time that they are making demand-side investment decisions for the future (solar or otherwise).
- It gives customers who have a low impact on the network or are willing to change behaviour a tool to reduce cost, by opting in to the tariff.
- It does not penalise customers who have invested in good faith under current arrangements; existing solar customers retain their benefits.
- No customer is required to take up the tariff unless they initiate change.

In addition, we are proposing to make the more advanced meter our standard regulated meter for all future asset replacements. This means that customers who have their meter replaced due to a bulk replacement program will receive a meter that is capable of supporting the tariff should they wish to opt in at a future time.

3.3 Tariff introduction timeline

The new capacity tariff was published in our July 2014 tariff manual [5] and is currently available on a limited opt-in basis for those customers who already have interval meters installed, or are willing to have them installed.

We propose to commence installing new tariff-capable meters as standard from July 2015, and to make the tariff available on a limited basis in the first two financial years of the 2015-20 period. We will introduce the new tariff as mandatory for all new and upgrade customers from July 2017, once the necessary systems and processes are in place (both within SA Power Networks and retailers) to support widespread adoption of the tariff.

We anticipate an average of around 70,000 meter replacements per annum from 2015. From 2017 onwards, around 56,000 customers per annum will move to the new tariff, as summarised in the table below.

Customer type	2015-16	2016-17	2017-18	2018-19	2019-20	New tariff	New meter
New customers	10,500	10,500	10,500	10,500	10,500	✓	✓
New solar/ other DER	19,505	25,664	26,680	27,112	29,737	✓	✓
Service alteration	1,500	1,500	1,500	1,500	1,500	✓	✓
Capacity tariff opt-in / pilot	1,000	1,000	17,299	16,389	15,489	✓	✓
Meter replacement (asset mgmt.)	22,251	23,200	23,600	25,750	13,500	×	✓
							2015-20 Totals
Total new meters p.a.	54,756	61,864	79,579	81,251	70,726		**348,177**
Total new tariff customers p.a.	1,000	1,000	55,979	55,501	57,226		**170,707**

Table 3 - Annual meter replacement and tariff rollout rates

The historical data and future projections on which these annual take-up rates are based are detailed further in Appendix B, but in summary:

- New customer connection forecasts are those used for network planning, and are based on demographic data and forecasts prepared by BIS Shrapnel [32]
- Solar uptake forecasts are based on modelling undertaken by Energeia [9]
- Service alterations are only those that involve a meter replacement, e.g. upgrade of supply to three-phase. Forecasts are based on historical data
- Annual voluntary opt-in rates are forecast at 2% per annum following the launch of the tariff, based on results from customer surveys undertaken by UMR [35]
- Bulk meter replacement rates are based on the Metering Asset Management Plan [31].

This approach will progressively phase in the tariff to reach ~50% of customers by 2025, as shown in Figure 7 below.

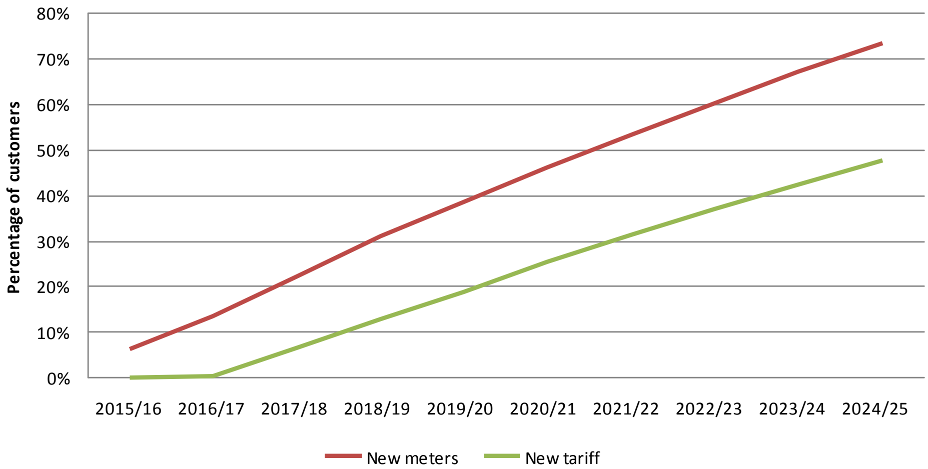


Figure 7 - Proposed new and replacement rollout schedule

3.4 Metering to support the tariff

In order to calculate peak demand for each month, we require a meter that is capable of recording the highest half-hourly consumption reached during the period. We have considered two options:

1. Install a type 5 meter and calculate peak demand each month based on an analysis of the interval data for the period.
2. Install a more advanced type 6 meter that is capable of measuring and recording the peak half-hourly demand reached during the month in a register, and allow customers to opt in to a type 5 meter if they choose to do so.

Option 1 is preferred as it is simpler, incurs immaterial additional costs, and there are additional benefits in having interval data for all customers. However, for this business case we have assumed that we may also have to support option 2. The reasons are set out in more detail in Appendix F, but in summary:

- State Government policy may mandate that customers must be able to 'opt out' of an interval meter to a type 6 meter [6].
- Current rules effectively prevent networks from enabling communications on type 5 meters other than in specific circumstances, and we want to retain the option to enable communications on meters for network purposes.

3.4.1 Maximising future value: a 'smart ready' meter as standard

Although our new basic regulated meter will remain as a manually-read meter, it will be upgradable, or 'smart ready' and will have a range of features in addition to basic metrology functions:

- The meter will be modular, with the capability to install an optional plug-in telecommunications module in order to enable remote reading and a range of other functions. A modular meter will allow for different telecommunications solutions to be used as circumstances dictate (e.g. mesh radio or 3G/4G), and interoperability with different vendor metering systems
- The meter will be able to be provisioned in one of three basic configurations for manual reading:
  - as a type 5 meter, which will be the default for all customers transitioning to the new tariffs
  - as a regular type 6 meter for those customers who require a new meter but are not required to transition to the new tariff, e.g. the majority of customers prior to 2017, or customers whose meters are replaced due to non-compliance as part of a bulk replacement program
  - as a type 6 meter with additional peak demand registers for customers on the new tariff who opt-out of a type 5 meter (if required).
- If the meter is provisioned as a type 6 meter with peak demand registers, it will operate as follows:
  - it will have the capability to measure half-hourly consumption during a defined time period each day (peak afternoon hours)
  - if the half-hourly consumption exceeds the current maximum for the month (or other billing period if required), it will be stored in a register, and the date and time that the maximum occurred will be stored in another register or

registers. These registers will be read manually by the meter reader along with the regular accumulated energy data

- The meter will be fully upgradable to type 4 or full 'smart meter' specification. This could be undertaken by any party accredited to provide type 4 metering services today[4], and once full contestability commences, by any party accredited to provide metering services.
- When a communications module is installed, the meter will be capable of providing all key functions described in the SCER-endorsed national SMI Minimum Functionality Specification [8], namely:
    - remote acquisition of interval data and meter event log data, with support for daily reads
    - remote connection and disconnection
    - quality of supply monitoring: to identify quality of supply issues within the distribution network, thus enabling more effective (and extensive) integration of renewable generation into the network
    - loss of supply ('last gasp') alarms and supply restoration notification
    - load management through a controlled load contactor (where installed), to support the separate controlled load circuits currently used by more than 300,000 customers in SA for off-peak hot water
    - supply capacity limiting, in the event of a shortfall of generation capacity in the market or potential network instability. Control at the meter offers the potential to reduce impact on the community relative to load shedding at the feeder level.
    - a home area network: enabling in-home displays and direct load control, and a key enabler for an open market for innovative demand-side services
    - remote meter service checking: to improve customer service and reduce unnecessary visits to customer premises by enabling a customer's supply to be tested remotely if they report a problem or to confirm supply restoration following repair works
    - additional customer safety features such as loss of neutral detection.

Standardising on a 'smart ready' meter for all new and replacement meter installations from 2015 aligns with policy goals to facilitate a transition to the more capable metering required to support new tariff models and new demand-side services at the least possible cost to the community. By operating the meter as a type 5 (or type 6) meter in the market by default we minimise the cost for those customers that only require a basic metering service, while retaining an upgrade path to enable additional metering functions for those customers that require them without replacing the meter[5].

As the meter population grows, these meters will also provide a platform to deploy low cost power quality monitoring by the addition of a telecommunications module in areas where this is beneficial – this is discussed in detail in section 5.

While we could potentially seek to source a lower-cost meter capable of measuring capacity that was not upgradable, any potential saving would be minimal given that the capital cost of

[4] Noting that these services are already subject to contestability.

[5] Noting that the modular nature of the meter means that an upgrade could be undertaken either by ourselves (as an unregulated service) or a third-party metering provider.

the meter itself is, on average, only ~50% of the overall cost of a new or replacement meter installation. Moreover, community expectations are clearly shifting towards the improved services that smarter meters can offer, with 78% of customers who took part in SA Power Networks' 2013 *TalkingPower™* survey indicating that they supported the installation of an advanced meter in their home or business [11]. We consider that the proposed meter represents the minimum essential specification for a meter in the 2015-20 period, and that installing a non-upgradable meter would be imprudent and ultimately result in stranded assets and higher cost to the community.

3.4.2 Future contestability in metering

In the context of a transition to a fully contestable market for metering, it is important to note that our proposal to move to a more capable meter as our standard regulated meter is compatible with the proposed role of the network as the default 'metering coordinator' (MC)[6] for residential meters as and when full contestability commences. It also does not in any way impede the market. It may turn out that there is a rapid and widespread retailer-led rollout of smart meters in South Australia once full contestability commences, or that customers who are upgrading their meter find that they can procure a better service or achieve a lower price from the open market than we provide through our regulated service. In that case, we may end up installing fewer new regulated meters once the new rules come into effect. Our metering Regulated Asset Base (RAB) will reduce relative to our projections, and our metering revenue will reduce accordingly. Such a market-led meter replacement will still achieve the primary goals of our regulated meter replacement strategy, so long as the following conditions are met:

- minimum meter specifications are set correctly, so that the new meters enable our capacity tariff and the network functions we require
- the proposed central gateway for meter access is in place, so we can access data from third party meters in a timely manner via a standard interface
- exit fees (or equivalent) are set correctly, so that those customers still paying a regulated metering charge are not disadvantaged.

As a prudent network operator we should not, however, rely on factors beyond our control to introduce tariff reform or to deliver the critical mass of smart-capable meters necessary to derive the network benefits we require such as enhanced power quality monitoring. The transition to a new contestable market may be delayed due to the complexity of the proposed market structure, or the rule change may not proceed at all in its present form. Even if new market rules come into force, retailers may choose not to install smarter meters, or they may not target the customers we need to target with our tariffs (noting that no customer will opt in to a tariff that leaves them worse off).

By raising the capability of our standard regulated meter we will ensure the minimum uptake rate per annum we require to phase in cost-reflective tariffs, stop installing 'dumb' meters that have little long-term value to the community, and establish a platform on which we can achieve additional network benefits through initiatives such as power quality monitoring, discussed further in section 5 below.

3.4.3 Other considerations

A non-reversion policy for interval metering operates in South Australia, so that once a meter has been replaced with an interval meter (type 5 or better) it cannot subsequently be downgraded to a basic accumulation meter. Hence once an interval meter is installed

[6] The AEMC's proposed name for a provider of metering services in the future contestable market, replacing today's *Responsible Person* role

(whether by us or a third party), we can assume that the new tariff can be supported at that premises from that point onward.

If the SA Government's proposed new and replacement meter policy [6] were to come into effect, all new and replacement meters would be required to be interval meters unless the customer explicitly opted to have a type 6 meter. In this case we would configure the meter as a type 6 with capacity registers for those customers that chose to opt out. This would ensure that those customers that opted out of an interval meter could still be transitioned to our capacity tariff. This position is reflected in our response to DMITRE's paper [24].

Finally, note that as the type 6 'capacity register' option has not previously been implemented in South Australia, there is an element of technical risk with this solution. This and other risks are summarised in section 8.

3.5 Expenditure

The introduction of the capacity-based network tariff impacts on expenditure in the following areas:

- metering services
- billing systems
- customer and retailer engagement.

These are described in the following sections.

3.5.1 Metering unit cost impact

The estimated average unit cost of a 'smart-ready' meter will be $63 higher than the average cost of a basic Type 6 meter today, as shown in the table below.

Meter type	Percentage	Basic Type 6	Modular, smart-ready
Single element	48%	28	99
Two element	28%	149	149
Three phase	24%	146	265
Weighted Average		**90**	**153**

Table 4 – Meter costs

Notes:

1. The tables compare the capital cost of the meter only. All costs associated with meter installation will be the same for a smart-ready meter as for a basic type 6 meter.
2. The costs in Table 4 are for a manually-read, smart-ready meter. They do not include the cost of the optional telecommunications module and associated infrastructure and IT systems.
3. Estimated costs for smart-ready meters are based on vendor pricing for the reference modular meter used in SA Power Networks' smart meter trials to date. Refer to the Meter Asset Management Plan [31] for further details.
4. Costs are in 2014 dollars and include handling and stores costs. The figures do not include business overheads or contingency.
5. The relative proportions of different meter types are based on 2012/13 RIN category analysis data.

3.5.2 Metering CAPEX impact

The total projected capital cost impact of moving to a capacity tariff-capable smart-ready meter as standard for the 2015-20 period is shown in Table 5 below.

CAPEX impact Smart-ready meters	Incr. cost $	Average qty p.a.	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20	Note
New customers	63	10,500	$3,323	665	665	665	665	665	
New solar	0	25,740	$0	0	0	0	0	0	(2)
Service alteration	0	1,500	$0	0	0	0	0	0	(2)
Tariff pilot / opt-in	0	10,236	$0	0	0	0	0	0	(2)
Meter replacement (AM)	93	21,660	$10,067	2,068	2,156	2,194	2,394	1,255	(3)
Total CAPEX impact			**$13,390**	2,733	2,821	2,858	3,058	1,919	

Table 5 – CAPEX impact: smart-ready meters

Notes:

1. Figures show projected CAPEX impact of adopting a smart-ready meter as standard compared to a Business As Usual (BAU) scenario in which we do not implement a new tariff, and instead continue to install least-cost accumulation meters.
2. For customer-initiated alterations (solar, service alteration and voluntary opt-in to the tariff) the net CAPEX impact is zero because we assume that these customers make a capital contribution that fully offsets the cost of the new meter.
3. The average per-meter incremental cost is higher for meters replaced under asset management (AM) programs than for new customer connections because a high proportion of AM replacements are older single phase, single element meters, which have the highest cost difference between a basic and a smart-ready meter. The average per-meter cost increment also factors in the assumption that when the dedicated controlled-load hot water meter requires replacement in a two-meter installation, the failed meter will be replaced with a two-element meter and the second meter will be removed.
4. Figures are in 2014 dollars and do not include any CPI escalation, overheads or contingency.

3.5.3 Metering OPEX impact

Small customers in South Australia with standard metering currently have their meters read, and their bills issued, quarterly. Customers who transition to the new capacity tariff will, however, require monthly billing if they are to respond effectively to the tariff.

Because customers transitioning to the new tariff will be geographically dispersed, the per-read cost of monthly manual meter reading for these customers only would be very high, comparable to one-off ‘special read’ costs initially. Per-read costs would also increase for the remaining customers as the ‘gaps’ created in existing quarterly read routes reduce efficiency. As a consequence, the incremental cost to read new tariff customers monthly quickly becomes comparable to the cost to transition *all* customers to monthly meter reading, which benefits from significant economies of scale. Further details of the comparative costs of monthly meter reading for new tariff customers only vs. all customers can be found in Appendix C.

Customer surveys have found that the majority of customers in South Australia have a preference for monthly billing [38]. Consumer advocates also cite monthly billing as a key tool to assist vulnerable customers in managing their electricity use and avoiding 'bill shock'. In its 2014 submission in response to DMITRE's new and replacement meter policy proposal, the South Australian Council of Social Services (SACOSS) wrote:

> *"SACOSS is of the view that the metering-related issue of most immediate importance to the consumers we represent is the issue of monthly billing based on actual meter reads – whether these be manual or remote reads."* [39, emphasis as in original]

Our proposed approach is to put in place specific arrangements for monthly meter reading for those customers that take up the new capacity tariffs under pilot or introductory schemes in the first two years of the 2015-20 regulatory period, and then to transition all small-market customers from quarterly to monthly meter reading from July 2017, to coincide with the broader launch of the tariffs.

Table 6 below shows the impact on total meter reading costs for the 2015-20 period.

OPEX impact Monthly meter reading / data processing	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20	Note
Transition to monthly reads, MDM and scheduling staff impact	$1,430	0	0	477	477	477	(2)
Old tariff type 6 customers - incremental cost of monthly register reads	$20,489	0	0	7234	6835	6420	(3)
New tariff type 5 customers - incremental cost of monthly probe reads	$4,202	84	168	669	1310	1971	(4)
Data processing: billing and backoffice - impact of monthly reads (T6 and T5)	$6,000	0	0	2000	2000	2000	(5)
Data processing: metering and validation - impact of monthly reads (T6 and T5)	$3,600	0	0	1200	1200	1200	(6)
Data processing: metering and validation - incremental cost of interval data (T5)	$658	2	4	111	216	325	(7)
Total OPEX impact	**$36,379**	86	172	11,691	12,038	12,393	

Table 6 – OPEX impact: meter reading and data processing

Notes:

1. Meter reading cost impact is the difference in cost vs. a BAU scenario in which all customers remain on quarterly meter reads.
2. Estimated internal resource impact of transitioning all customers to monthly reads is 4 x FTE impact in MDM team and 1 x FTE meter read scheduling
3. Cost estimate for customers remaining on old tariffs assumes 8 x additional reads per annum per customer at current negotiated per-customer read rates, an incremental cost of $8.88 per customer per annum.
4. The incremental cost of monthly meter reading for new tariff customers is calculated as follows. In 2015-16 and 2016-17, those customers that transition to the new tariff under initial pilot / opt-in schemes are transferred from scheduled quarterly read routes to an

interim monthly meter reading arrangement. As there are too few such customers to achieve efficiencies of scale, these customers have an estimated additional meter reading cost of $84 per customer per annum, based on current negotiated rates for one-off 'special reads.' After July 2017 all customers transition to monthly reading as standard and economies of scale are restored. The estimated incremental cost of monthly meter reading for new tariff customers from July 2017 onwards is $11.54 p.a., based on 8 x additional reads per annum at current negotiated quarterly read rates, plus a 20% uplift to allow for the additional cost of type 5 reads (probe reading) vs type 6. Refer Appendix C for further details.

5. Estimated impact on billing component of CHED services contract cost of transition to all-monthly billing
6. Estimated impact on data processing and validation component of CHED services contract due to transition to all-monthly meter reading
7. Estimated internal resource impact of 0.5 x FTE per 50,000 interval meters
8. All items other than item (5) are associated with meter reading functions and hence are Alternative Control Services impacts. Item (5) relates to network billing and is a Standard Control Services function.
9. Figures are in 2014 dollars and do not include any CPI escalation, corporate overheads or contingency.

As can been seen in Table 6, transitioning customers to monthly meter reading results in a significant step change in metering and billing OPEX. As the majority of this OPEX is recovered through the ACS annual metering charge, this will have an estimated impact of $8-$10 per annum on the metering charge in the 2015-20 period.

3.5.4 Backoffice system upgrades to support the new tariff

SA Power Networks' current billing and customer information systems have reached end-of-life and lack the capability to support emerging requirements such as new tariffs, more advanced metering, and more sophisticated customer interactions arising from increased demand side participation. We are proposing a program of work in the 2015-20 period to progressively upgrade these systems to a modern Customer Information System (CIS) and Customer Relationship Management (CRM) platform. The new CIS / CRM platform will:

- have the flexibility to support new tariffs, from a computation and billing perspective
- facilitate the management of changes to customers' metering arrangements as small-market customers begin to migrate to third-party contestable meter providers
- provide a more effective platform to manage customer information, track customer contacts and actively support customers through the significant change associated with the transition to capacity-based tariffs
- provide a platform for self-service customer information e.g. web portals
- replace a number of disparate systems with bespoke interfaces with a modern service-bus architecture that will be flexible and extensible to accommodate future requirements, noting that we expect customer needs to develop and change in the next ten years as they are exposed to many new demand-side product offerings, new market players and new technologies.

The proposed system upgrades are set out in detail in the *CIS & CRM Business Case* [40]. This section outlines the specific work required to support the new capacity tariff, and to accommodate the higher number of meter reads associated with monthly billing. The estimates herein assume that the underlying CIS and CRM platform is upgraded as planned.

We will support two possible ways to calculate the capacity tariff, depending on the meter type:

- based on interval data, for customers who have an interval meter, either because we have installed a regulated type 5 meter, or because they have taken on an interval meter from another provider and we receive the data via the AEMO B2B hub. Calculation of the tariff from interval data can be achieved using the base capability of the billing platform and requires no additional spending.
- based on a single monthly peak demand figure read from a register in one of our advanced meters that is configured as a type 6 meter. In this case the billing systems will also need to ensure that the date and time of the peak interval can be obtained by the retailer for inclusion on the customer's bill. This is a new capability that requires changes to multiple systems (refer Appendix F for details) that are not costed as part of the *CIS & CRM Business Case*.

As noted earlier in section 3.4 we intend to provision meters as type 5 by default, but we have identified specific circumstances in which it may be necessary to support a type 6 meter. The extent to which these circumstances will arise depends on outcomes of the metering contestability rule change process and SA Government policy. The cost to support a type 6 solution is potentially avoidable if all meters could be provisioned as type 5, which would be our preferred outcome.

We will also require a significant increase in the number of handheld meter reading devices to support the proposed transition to monthly meter reading for all customers from mid 2017.

The tables below show the estimated capital and ongoing operating costs associated with these updates.

CAPEX Base IT costs to support capacity tariff	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20	Note
Upgrades to billing and meter reading systems to support capacity tariffs with a type 6 meter	$912	912	0	0	0	0	(1)
Additional meter reading handheld devices	$1,352	0	0	1352	0	0	(2)
Total CAPEX	**$2,264**	912	0	1352	0	0	

Table 7 – CAPEX impact: billing and meter reading systems

OPEX Base IT costs to support capacity tariffs	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20	Note
Upgrades to billing and meter reading systems to support capacity tariffs with a type 6 meter	$248	0	62	62	62	62	(3)
Total OPEX	**$248**	0	62	62	62	62	

Table 8 – OPEX impact: billing and meter reading systems

Notes:

1. Estimated cost of system changes to support the tariff with a type 6 meter with additional registers for time- and date-stamped peak demand values; refer Appendix F for details of the required changes. The cost estimates were prepared by Deloitte. A detailed cost breakdown is provided in the associated IT costing paper; refer Appendix D for details.
2. SA Power Networks currently has 130 handheld meter reading devices to support quarterly reads, including spares, replaced on a rolling basis. The transition to monthly reading will increase the number of meter reads by a factor of three, and require an estimated 240 additional devices in 2017 at a unit cost of $5,633 based on current vendor pricing.
3. OPEX allowance is for 0.5 FTE to support the upgraded systems, based on the internal daily rate for an IT systems support analyst.
4. IT estimates as shown include departmental overheads and contingency according to standard methodology for IT cost estimation. Figures are in 2014 dollars and do not include any CPI escalation.

3.6 Customer and retailer engagement

Customers have become accustomed to the fact that their electricity costs are directly related to the total amount of energy they consume, and generally understand how to save energy in order to save money. Market research undertaken as part of SA Power Networks' capacity tariff trials in 2013 and 2014 [10] has shown that customers, in general, are not aware that their peak demand also has an impact on costs, and do not know what their peak demand is or how to manage it.

The introduction of a capacity-based network tariff that exposes customers to the cost of their peak demand will require an extensive customer engagement program to ensure customers are provided with the information and tools they require to understand the new tariff and respond in ways that minimise their costs, should they wish. Retailers will also require education and support to enable them to incorporate the tariff in their product offerings, and understand the potential impacts on customers.

A comprehensive customer and retailer engagement strategy has been developed within SA Power Networks' Customer Relations and Corporate Communications teams [12] that sets out in detail the resources required to support the introduction of the new tariff. This will include:

- public education through a media campaign comprising TV, radio, print and digital media
- development of customer information packs to be provided to all customers transitioning to the new tariff
- consultation with customer interest groups on the impact of the tariff

- consultation with retailers and government on the proposed changes
- training of call centre staff to support customer enquiries in the lead up and during the implementation phase of the program
- Additional call centre resources to manage expected volumes of customer enquiries arising from the new tariff
- development of policies and procedures to support retailers
- the development of internal systems and business processes to facilitate the transition

Full details of these activities, and the associated costs, are included in [12]. At a high level the work includes the establishment of a dedicated team within Customer Relations to undertake a significant business process change project in the first 24 months of the 2015-20 period to prepare the business for the mid-2017 launch of the tariff across the residential and small business customer base, including the transition to monthly meter reading as standard. During this time there will be associated capital expenditure in the development of customer and retailer education and training materials, advertising materials and information packs, in the development of detailed policies and procedures in relation to the tariff to ensure a smooth transition and minimise any negative customer impacts, and in engagement with retailers and others to ensure our industry partners are prepared.

From mid 2017 there will be a significant increase in customer call centre staffing levels to support anticipated call volumes arising from the new tariff. At a high level the impact on customers, and the associated customer support workload, is expected to be comparable to that associated with the introduction of solar feed-in tariffs in the present period.

Table 8 below shows the estimated capital cost of the proposed customer and retailer engagement program during the tariff implementation phase.

CAPEX New tariff customer engagement	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20
Project team and PM	$4,037	2019	2019	0	0	0
Education and training	$1,249	848	402	0	0	0
Policy and procedures	$127	100	27	0	0	0
Industry engagement	$343	123	219	0	0	0
Total CAPEX	**$5,756**	3090	2666	0	0	0

Table 9 – CAPEX impact: customer engagement

Table 10 shows the estimated operational cost of ongoing customer support associated with the progressive rollout of the tariff through the 2015-20 period.

OPEX New tariff customer support	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20
Customer advice and support staff	$8,308	0	664	2294	2622	2727
Policy and procedures	$264	0	66	66	66	66
Advertising – production	$161	0	127	0	34	0
Advertising – media	$2,151	0	698	470	484	499
Customer information packs	$1,024	6	6	336	333	343
Total OPEX	**$11,908**	6	1561	3166	3539	3635

Table 10 – OPEX impact: customer engagement

Notes:

1. OPEX estimates are based on modelling estimated customer call centre contact rates arising from the introduction of the new tariff, as well as ongoing retailer support. The cost profile is based on an additional 6 customer support FTEs in 2016-17 to support up to 2,000 initial / opt-in customers prior to the mid 2017 tariff launch, increasing to 22 FTEs in 2017-18 to support the estimated 56,000 customers expected to transition to the tariff in the first year following the launch. Thereafter the number of customers transitioning to the tariff each year is relatively constant. As the majority of customer contacts are expected to occur in the first year after moving to the tariff, customer support FTE requirements remain relatively constant, rising slightly to 26 FTEs by 2020.
2. Figures are in 2014 dollars and do not include any CPI escalation, corporate overheads or contingency.
3. Full details of cost estimates can be found in the customer and retailer engagement strategy [12].

3.7 Outcomes

3.7.1 A sustainable tariff: halting inequitable cross-subsidies

As noted in section 2.1, due to the rapid and widespread uptake of residential solar power that has occurred since 2010, today's energy-based network tariffs cause significant cross-subsidies from those consumers that do not have solar power to those that do. Additional cross-subsidies exist between those customers with large, infrequently used air-conditioning systems and those with smaller systems. Continued inefficient purchase and usage decisions by customers that can afford solar systems, large air-conditioners, and potentially new technologies such as electric vehicles and residential battery systems, will tend to push network costs on to an ever-decreasing number of customers who are increasingly disadvantaged.

Detailed economic modelling undertaken by consultant Energeia [9] shows that the proposed transition to a cost-reflective network tariff based on capacity will lead to reduced network price increases in the next 20 years when compared to alternatives, by addressing the 'death spiral' of cross-subsidy and changing consumer behaviour and demand-side investment patterns to use the network more efficiently. This is seen in Figure 8 below which shows long-term network price trajectories for residential customers under four tariff scenarios, assuming all other factors are equal:

- IBT is a 'business as usual' scenario where IBT network tariffs continue.
- ToU is a scenario where network tariffs transition to Time of Use.

- MD + ToU is a scenario where a capacity tariff ('MD' for 'Maximum Demand') is phased in from year 1 according to our proposed new and replacement rollout model[7], and is combined with retail ToU tariffs.
- MD + DPP is a scenario where a capacity tariff is combined with retail Dynamic Peak Pricing[8] tariffs.

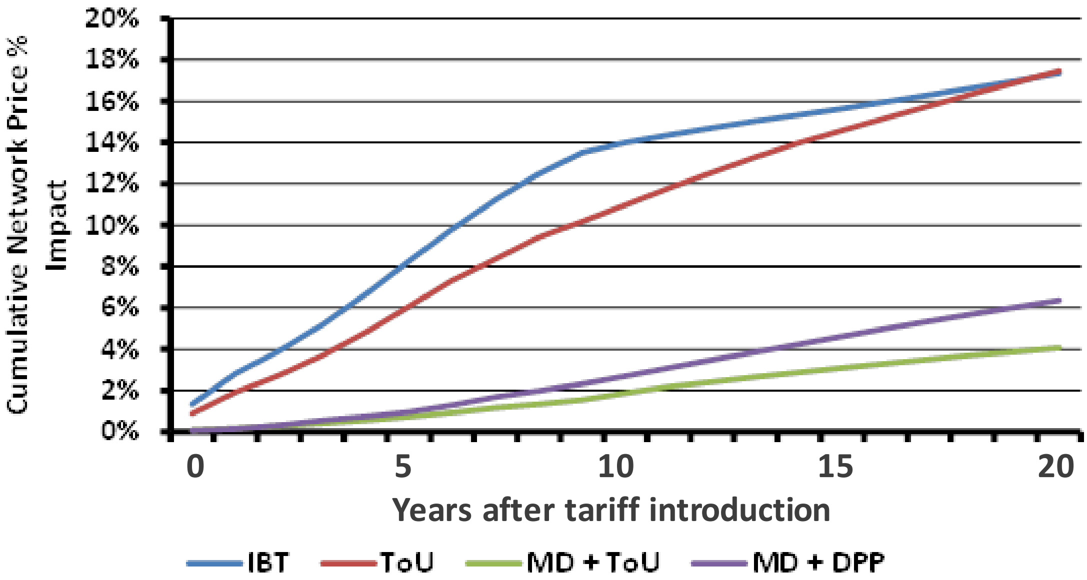


Figure 8 – Network price impact of different network tariffs, residential customers (adapted from [9])

The figure shows that, given the same initial conditions, the scenarios in which a capacity tariff is introduced result in a significant moderation of network price growth over time. For residential customers, ongoing shifting of network costs results in a price increase of 10% over a 5 year period under a BAU scenario, whereas this impact reduces to less than 2% under the capacity tariff scenarios[9].

Energeia's modelling also predicts that, in the absence of tariff reform, a customer in 2034 without distributed energy resources (DER) will be paying roughly 50% more in network charges than an equivalent customer who has adopted DER.

These findings align with recent research by AEMC that found that up to 81% of customers would face lower network charges in the medium term under a cost-reflective capacity price [46].

3.7.2 Societal benefits: more efficient demand-side investment

Today's energy-based network tariff sends a price signal that is artificially skewing the market for DSP generally towards generation. When the cost of the network is properly exposed and shared equitably through a capacity-based tariff, consumers will have an incentive to target their available funds to a mix of demand-side investments, including those that reduce network costs as well as energy consumption. Options such as home insulation, battery

[7] In fact, Energeia's model uses a simplified version of our proposed rollout schedule, but the difference is not considered to be material.
[8] Dynamic Peak Pricing is similar to CPP
[9] It is important to note that this modelling focuses specifically on the cumulative network price impact arising from the tariff under a basic set of assumptions around network revenue requirement that is common to all models. It does not seek to model the actual absolute change in network revenue requirement over time, which will depend on many factors independent of the tariff.

storage, smart appliances, etc. will assume their proper value relative to embedded generation, and the markets for these will function efficiently.

Consumers will also have incentives to make choices such as orienting their solar panels westward[10], running their washing machine overnight, or starting their air-conditioner early on hot days to pre-cool their houses – choices that may deliver a real reduction in their bill by reducing the network component, without requiring any additional investment. These zero-cost/positive-benefit choices represent untapped value to the community that will be realised once tariffs are properly cost-reflective and customers have the opportunity to be rewarded for using the network more efficiently.

Energeia's modelling [9] examined the impact of tariff reform on the future uptake of demand-side technologies in South Australia including solar PV, gas powered Combined Heat and Power (CHP) systems, battery storage systems and electric vehicles (EVs), taking into account a range of other factors such as projected technology price paths and the future cost of gas. The outputs of the economic model support the view that introducing a cost-reflective network tariff will result in a more efficient mix of demand-side investment in the long term.

Figure 9 below shows Energeia's long-term predicted uptake rates for different demand-side technologies in South Australia under (a) a BAU scenario in which energy tariffs remain as they are today (IBT) and (b) under our proposed capacity-based network tariff, combined with retail ToU tariffs.

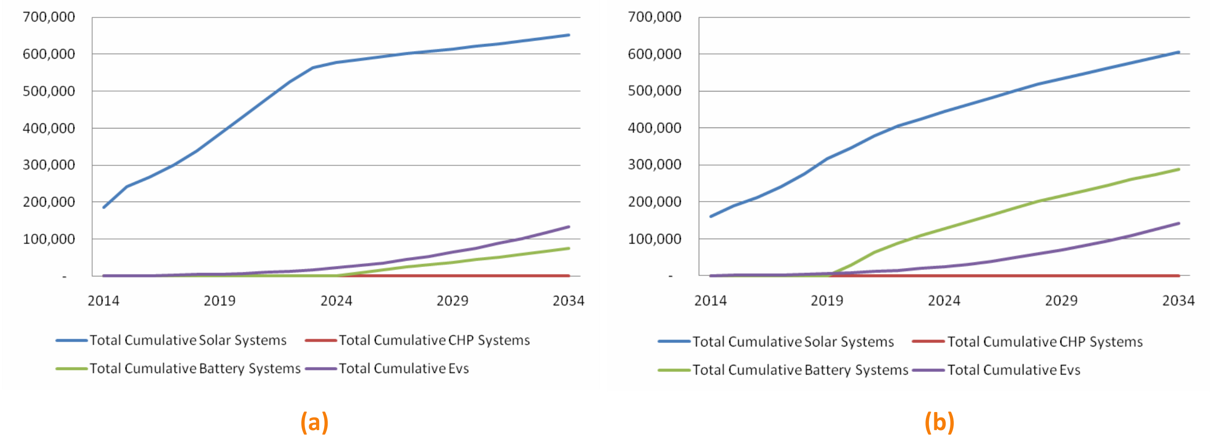


Figure 9 – Projected demand side technology adoption under (a) IBT and (b) capacity tariff + ToU (source: Energeia)

When consumers invest efficiently, the overall societal cost across the whole energy supply chain, including both grid-supplied energy and demand-side investments, will be minimised.

Although these are broader benefits to society that arise across the whole energy supply chain rather than benefits realised directly through SA Power Networks' business, they demonstrate alignment of our proposed transition to a capacity tariff with the National Electricity Objective (NEO), namely:

> *"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity..."* [13]

[10] AEMC has estimated that simply orienting PV panels westward rather than to the North would save $88 per customer per annum in network costs [46]

4 PREPARING FOR MORE ADVANCED METERING

We must prepare for a significant uptake of interval meters across South Australia over the next ten years, including many that may be full-featured smart meters with remote communications. This is because:

- We intend to offer interval metering as the default service to those customers who transition to our new network tariff, taking into account the AER's re-classification of type 5 metering as a regulated, rather than a negotiated service in South Australia [23].
- The proposed metering contestability rule change, expected to come into effect mid-way through the 2015-20 period, is intended to stimulate a market-led rollout of smart meters by third-parties. As more third-party smart meters begin to be installed in the latter part of the 2015-20 period, we expect to receive increased volumes of interval data from these meters via the AEMO B2B hub.
- The SA Government's proposed new and replacement policy, should it be adopted, would require *all* new and replacement meters to be interval meters unless the customer explicitly opted to have a type 6 meter.

The transition to more widespread adoption of interval meters and smart meters, potentially operated by a number of different metering providers, will require changes in SA Power Networks' business processes and the IT systems that support them. These changes will be facilitated by the new billing and customer data management platform that will be developed under the program of work described in the *CIS & CRM Business Case* [41].

The sections that follow describe specific enhancements to the base platform that will be required to manage increasing volumes of interval data and enable access to network monitoring and control capabilities in third-party smart meters. The associated costs have been estimated assuming that the core CIS and CRM systems are upgraded as planned, and are in addition to the platform development costs included in the *CIS & CRM Business Case.*

4.1 The transition to full metering contestability

Under the draft rule change proposed by SCER, distribution businesses will lose their monopoly right to install certain types of meter, and metering services will become fully contestable, with the retailer responsible for appointing a Metering Coordinator (MC) to provide metering services at market rates and pass the cost on to the consumer.

Under the proposed rule change SA Power Networks will begin as the MC for all type 5 and type 6 meters. Hence we expect the latter part of the 2015-20 period to be a period of transition, during which we will retain a significant asset base of manually-read meters, but one that may begin to diminish once the rule change comes into effect, as these meters are displaced by some customers opting to take up more advanced metering services.

4.2 Business impacts – increased volumes of interval data

There are only around 12,000 customers with interval meters in South Australia today, of which the majority (around 8,000) are commercial and industrial customers with type 1-4 meters and the rest have type 5 meters. These customers represent just 1.5% of SA Power Networks' customer base overall. As a consequence, our billing systems and associated IT systems have not historically required the capability to store or process interval data at mass market volume.

In order to prepare for the anticipated uptake of interval metering during the 2015-20 period we require an upgrade to the billing systems that handle interval data received via the NEM from third party Meter Data Providers (MDPs), and our internal systems for processing and storing this data for both billing and network planning purposes.

While we expect that the majority of customers will transition to interval metering over the next ten years, the initial rate of uptake in the 2015-20 period will be subject to factors outside of our control. For the next regulatory period, we propose that it is prudent to add sufficient data capacity for no less than 300,000 interval meters by 2020, assuming a linear ramp-up through the period. This is the estimated rate at which interval meters would be installed should the SA Government's proposed new and replacement policy be implemented from 2016, and is an upper bound for the number of customers transitioning to an interval metering service based on current projections of meter installation and replacement rates.

It is possible that retailers may offer new products that drive demand for meter replacements beyond these levels, in which case some further investment may be required to add additional capacity.

4.3 Business impacts – multiple meter providers and the common market gateway

The AEMC Working Group on Open Access and Common Communication Standards for Smart Meters has recommended that as part of the metering contestability rule change AEMO should establish a new 'common market gateway' through which accredited parties, including network businesses, can access smart meter functions [16]. It is proposed that all future metering providers will have to provide access to their meters via the common gateway.

The precise nature of the gateway is yet to be determined. At the time of writing, the COAG Energy Council has tasked AEMO with developing the new shared market protocol, building on the recommendations of the AEMC Working Group [43]. The AEMC's preliminary proposal is:

- Existing B2B processes will be extended with a new set of smart meter services, accessed using a standard protocol.
- The standard protocol for new services will be based on web-services or similar, in keeping with the services that Victorian DBs have implemented for retailers for remote disconnect/reconnect and HAN device binding. The new protocol will allow for transactional / near-real-time services in addition to today's batch data exchange services.
- Available services will be based on those defined in the SMI Minimum Functionality Specification, but not all services may be available at every metering installation (depending on the national minimum functional specification and any other services that are mandated through jurisdictional new and replacement policies).

Given the timing of the proposed rule change, we expect the common gateway to become available mid-way through the 2015-20 period, potentially phased in with simple services available first.

In the proposed contestable market, we will require access to the network functions provided by third-party smart meters, both to preserve services such as hot water load control that exist today when our own meters are replaced with third-party smart meters, and to ensure that the network benefits that smart meters will enable can be accessed as these meters are rolled out. We propose, in the 2015-20 period, to implement interfaces to the common market gateway, including all associated authorisation, security and auditing functions, and to establish the backoffice systems required to manage and process the data and integrate with other systems such as OMS and ADMS in order to realise network benefits.

Noting that the details of the common market gateway are still to be finalised, we have based our budget estimates on the best information currently available and on informed assumptions regarding what services are likely to be available through the gateway and how they will work. We propose to integrate with the following five basic services:

1. Controlled load (e.g. hot water) operation / configuration – a service to configure regular daily on/off times for a set of NMIs, and also a service to directly switch the load on/off in near-real time. This will also require a corresponding near-real-time event notification to confirm that load control has operated.

   Initially this will be required to preserve existing hot water load control functionality (via the controlled load contactor) when a regulated meter is replaced, but the same service could potentially be used in future for any controllable load in the house (e.g. pool pump, air conditioner, battery storage). This will enable switching times to be optimised, create opportunities for new controlled-load tariffs, and ultimately enable customer hot water load to be managed more actively to enable future elements of the *Flexible Load Strategy* [1].

2. Power quality (PQ) and event data – a service where we can subscribe to PQ data and general events (e.g. voltage excursions events, tamper detection, etc.) from a set of meters and this will be delivered to us (a) on a daily basis in a file, alongside the daily interval data, and (b) in near-real-time for threshold alarms and critical events.

   We will use this for LV modelling as well as targeted power quality solutions, e.g. in areas of high solar PV penetration. We assume that daily per-meter data volumes will be no greater than 30 minute interval data and we will require no more than 12 months' on-line storage for up to 300,000 meters in 2015-20.

3. Last gasp /service restoration – a service where we can subscribe to power outage alarms from smart meters in near-real-time.

   We assume there will be a single transaction to subscribe, after which we will receive unsolicited messages from the gateway when meters go off-supply – either one per alarm, or batched in some way (i.e. a single message could containing a set of NMIs that had issued last-gasps in a 1 minute period). We will also receive service restoration messages when supply is restored. We will feed these alarms into OMS, and implement the necessary logic and filtering to correlate events.

   These messages can be used to determine the location of network faults or storm damage and confirm when repair efforts have been successful, potentially improving fault restoration times and customer service. We would also make use of the data when calculating Guaranteed Service Level (GSL) payments.

   The Victorian DBs have experience with this activity, albeit from their own Meter Management System (MMS) only, and we have sought input from these DBs in preparing budget estimates.

4. Main supply contactor operation (remote disconnect / reconnect) – a service whereby we:

   - receive notification from the market gateway when a retailer executes a supply disconnection / reconnection using a smart meter we do not control, and update our internal records accordingly

   - potentially submit a remote disconnect / reconnect request to the gateway to disconnect or reconnect a customer whose meter we do not control, e.g. for emergency load shedding.

5. Real-time ping – a service where we can send a transaction to the gateway to 'ping' a NMI or set of NMIs and receive back in near-real-time a message indicating status of that meter (on/off supply, but also things like state of the controlled load contactor, instantaneous voltage and power consumption).

   We will use this for:

   - call centre validation of loss of supply when a customer calls in
   - call centre investigation of customer PQ complaint
   - targeted investigations of performance of sample meters in an area of interest, e.g. a high solar PV area.

   In 2013, SA Power Networks' crews attended 9,830 jobs at customer premises for issues that turned out to be customer-side problems, and hence there is the potential both to improve customer service and avoid the expense of wasted truck rolls.

   In addition to the gateway interface we will need a simple user interface (UI) to choose and ping a NMI or set of NMIs (The Victorian DBs have implemented these, interfacing to their own MMS only).

In choosing to budget for the above services we have taken into account:

- the services as defined in the SMI Minimum Functionality Specification
- discussions through our participation in the relevant AEMC and AEMO working groups regarding a reasonable minimum set of network services to be provided through the gateway, and the position we have advanced through our formal submissions to these groups [14,15]
- the minimum set of functions stipulated in the SA Government's proposed new and replacement policy for communication-enabled meters, which include three of the five services we have allowed for: remote reading, disconnect/reconnect and loss of supply detection
- our assumption that we must allow for the case where an existing meter with controlled load is replaced by a third party's meter and we are required to access the function via the common market gateway in order to continue to provide the controlled-load tariff
- our own priorities for accessing the potential benefits from smart meter data, in particular the value of customer-premises power quality data in managing the low voltage network in areas of high solar penetration.

4.4 Costs

The tables below show the capital and operating costs in the 2015-20 period required to upgrade SA Power Networks' IT systems, and the associated business processes and support functions, to prepare the business for the expected uptake of interval metering, the transition to full contestability in metering services, and the establishment of the AEMC's proposed common market gateway for smart meter information exchange.

CAPEX Base IT costs to support interval meters / contestability	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20	Note
IEE, MTS upgrades to support interval metering	$3,485	0	0	2130	1258	97	(1)
Infrastructure growth - data archival	$1,246	107	178	249	320	392	(2)
Data warehouse and analytics - interval data	$1,192	0	0	364	358	470	(3)
Meter service: PQ data & event analysis	$1,049	0	0	582	408	59	(4)
Meter service: Last gasp	$2,682	0	0	1290	1037	355	(4)
Meter service: Ping	$1,038	0	0	952	86	0	(4)
Meter service: Remote de-en/re-en	$929	0	0	492	380	57	(4)
Meter service: Controlled load	$1,478	0	0	823	573	82	(4)
Security systems - design, implement	$718	0	0	599	119	0	(5)
Contestability – business process change	$1,961	484	1234	242	0	0	(6)
IT program management / project costs	$2,070	216	371	587	525	371	(7)
Total CAPEX	**$17,848**						(8)

Table 11 – CAPEX impact: IT costs to support smarter meters

Notes:

1. Upgrades to IEE and MTS to support up to 300,000 additional interval meters by 2020. This is an uplift cost in addition to the cost of base platform upgrades.
2. Storage capacity upgrades to support 7 year archival of interval / PQ data
3. Data warehouse and analytics platform for processing interval data for network planning, ADMS integration, etc. Cost estimates based on SAP BW as the data analytics platform, and include interfacing to IEE and OMS and report development.
4. Costs to integrate third-party meter services include implementation of interface to common market gateway and associated conformance testing, as well as data processing, storage, reporting and all interfaces to other internal systems such as OMS and ADMS (depending on the service), UI implementation etc. as described in section 4.3. Costs also include related business process change management to integrate smart meter services as part of business-as-usual operations.
5. Security systems design and implementation to securely integrate access to third-party meter services via the new market gateway with internal systems. Includes allowance for initial security assessment, design and implementation in accordance with future AEMO market gateway provisions for authentication, authorisation and accounting (AAA), security testing and updates to the Information Security Management Framework (ISMF).
6. Implement business processes for meter transition to 3rd party MDPs and management of multiple meter providers, participation in AEMO governance arrangements for market gateway, meter asset transfer processes, etc. Assume team of 4 x FTE plus allowance for related third party products and services in year 2.

7. IT project management and oversight during project execution. Average of 3 x FTEs in years 1,2,4 and 5, maximum of 6 FTEs in year 3.
8. The above estimates have been prepared by Deloitte for IT, drawing on experience from the Victorian AMI program, and take into account planned upgrades to the CIS and CRM platforms. A detailed cost breakdown is provided in the associated IT costing paper; refer Appendix D for details.
9. IT estimates as shown are in 2014 dollars and include departmental overheads and contingency according to standard methodology for IT cost estimation.

OPEX Base IT costs to support interval meters / metering contestability	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20	Note
Interval data processing / billing support	$953	0	143	191	286	334	(1)
IT systems support – Security and data analytics	$753	33	55	151	230	284	(2)
IT application support – base IT systems	$800	0	0	220	264	316	(3)
Contestability – 3rd party provider management	$969	0	242	242	242	242	(4)
Total OPEX	**$3,723**	33	502	866	1084	1238	

Table 12 – OPEX impact: IT costs to support smarter meters

Notes:

1. Additional staff resources for processing increased volumes of interval data. This is for billing-related staff costs, and does not including data processing and validation associated with meter reading functions, which are accounted for in meter reading cost estimates in section 3.5.3. Estimated impact is 0.5 x FTE per 50,000 interval meters.
2. Vendor support and maintenance of data analytics hardware and software estimated at 20% of CAPEX, plus $75,000 p.a. for ongoing security assessment and security management services. Estimate prepared by Deloitte for the associated IT costing paper; refer Appendix D for details.
3. Ongoing application and user support and maintenance for billing related systems, data analytics, ADMS and OMS integration, and external market gateway interfaces. Estimated requirement of 2 x FTE in years 2 and 3 rising to 2.5 FTE in years 4 and 5. Estimates prepared by Deloitte for the associated IT costing paper; refer Appendix D for details.
4. New role, 2 x FTE to manage ongoing commercial and logistical arrangements with multiple meter providers, including meter asset transfer.
5. All costs are in 2014 dollars. IT estimates (items 2 and 3) include departmental overheads and contingency according to standard methodology for IT cost estimation.

The above activities represent a necessary investment in IT systems and business processes to ensure that the business has the capability to manage the expected growth in interval metering and the introduction of smart metering in the 2015-20 period.

This includes establishing the capability to transition load control functionality to third-party meter providers, and establishing the interfaces required to access future network benefits from smart meters via the proposed B2B gateway. This will ensure that a market-led smart meter rollout is not impeded and, as customers take on smarter meters, we will be able to access the power quality data, event alarms, control and diagnostic functions that these meters can provide, and make use of these to provide improved reliability and quality of supply and more efficient operation of the network. Without this access, network benefits would not be realised, and a significant portion of the value of the community's investment in smarter meters would be lost.

4.5 Future benefits

Future network benefits from smart meters will become available once the new B2B gateway is fully operational and a critical mass of meters has been established. In order to estimate the potential value of these benefits, we have made reference to two recent studies:

- Deloitte's 2011 review of the future benefits of the Victorian smart meter rollout, which itself reviewed a number of earlier studies. This review was undertaken part-way through the Victorian rollout and took a conservative approach to its estimates of the available network benefits from smart meters, revising a number of previous benefit estimates downward [21]
- Energeia's 2014 *Review of Potential Network Benefits of Smart Metering* prepared for the Australian Energy Networks Association (ENA) [27]. This study re-examined the Deloitte 2011 report in the context of the most recent information available from the Victorian network businesses, and also took into account the findings of the *Smart Grid, Smart City* program and other relevant studies published overseas since the Deloitte 2011 work.

Deloitte and Energeia differ considerably in their estimates of the value of available network benefits per smart meter, as shown in the following table.

	Maximum benefit per meter ($)		
Benefit category	Deloitte	Energeia	Note
Capacity	19	49	
Power Quality	5	34	
Reliability	7	36	
Safety / other	9	-	(2)
Total	41	119	
Total excluding capacity benefits	**21**	**70**	(3)

Table 13 - Estimated maximum available benefit per smart meter

Notes:

1. Figures are based on Figure 1 in Energeia's report [27].
2. Deloitte included benefits relating to emergency response and safety. Energeia did not separately estimate these.
3. In order to estimate the future benefits attributable to the five smart meter functions set out in section 4.3 we have excluded all benefits arising from future peak demand reduction, categorised by Energeia as 'capacity' benefits, and only considered those benefits attributable to power quality, reliability and safety/other.

Most network benefits require a minimum number of smart meters before they can be realised. Energeia's study is particularly relevant in this regard as it looked specifically at the extent to which network benefits would be realised as meter penetration increased under a market-led smart meter rollout, as opposed to the network-led rollout in Victoria.

Figure 10 below illustrates how available network benefits are expected to increase as the penetration of smart meters increases under a market-led rollout. This figure is based on Figure 2 in Energeia's report [27], modified to exclude capacity benefits. Energeia found that in an untargeted market-led rollout network benefits are unlikely to accrue until meter penetration reaches 20-30%.

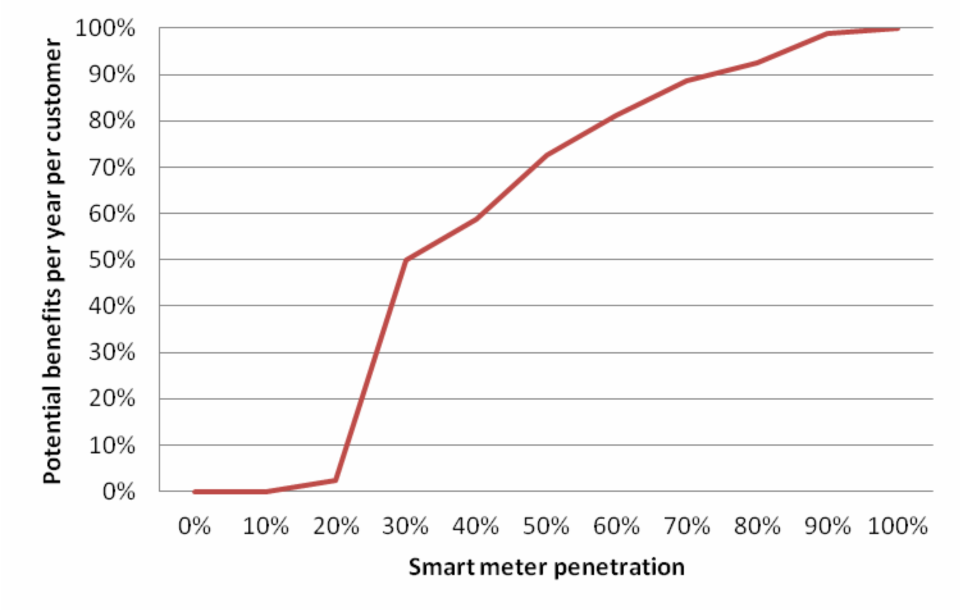


Figure 10 - Network benefits realisation by smart meter penetration

We have considered two scenarios for meter penetration under the proposed market-led rollout. Assuming that the rollout begins with the commencement of new metering contestability rules sometime in the 2016/17 financial year, we have modelled:

- A low-growth scenario, in which we assume smart meter penetration reaches 5% by 2017/18 and grows at 5% per annum thereafter
- A high-growth scenario in which we assume smart meter penetration reaches 5% by 2017/18 and grows at 10% per annum thereafter. In this scenario 100% meter penetration is reached in 2028.

Figure 11 below compares estimated future benefits under these two scenarios using the Deloitte and Energeia estimates of maximum available benefit per-meter (excluding benefits due to demand reduction).

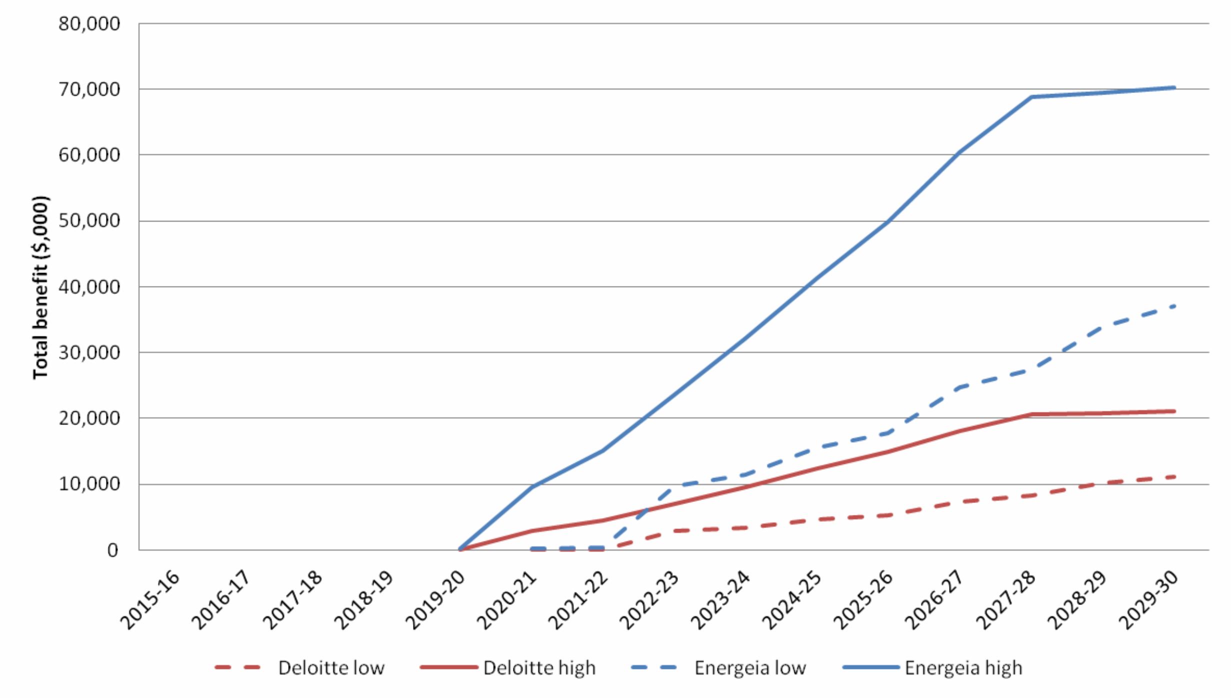


Figure 11 - Estimated future network benefits from smart meters under a market-led rollout

These estimates indicate that the future benefit from access to network functions in smart meters via the proposed market gateway would be in the range of $21 million (Deloitte, low growth scenario) to $180 million (Energeia, high growth scenario), NPV over 15 years from 2015. This would be in addition to benefits from demand reduction arising from tariff reform and future demand management programs.

Even utilising the Deloitte low scenario, the NPV of these benefits significantly exceeds the cost of implementing the systems to support these functions (an $8-9 million NPV component of the total CAPEX and OPEX set out in section 4.4 above).

It should be noted that the extent to which these available benefits are realised will depend on the outcomes of the metering contestability rule change and associated processes. Network benefits will only be fully realised if there is:

- an adequate minimum specification for smart meters that includes all network functions described herein, such as the COAG-endorsed national minimum specification
- a well-defined market interface such as described in section 4.3 that is standard across all metering coordinators
- a functioning regulatory framework for networks to access functions in smart meters owned by commercial metering coordinators.

5 SMARTER METERS AS A PLATFORM FOR POWER QUALITY MONITORING

The previous section set out our proposed approach to seek access to network functions in smart meters owned by third parties via the AEMC's proposed common market gateway, as the market develops. While we expect this to deliver substantial operational benefits in the long term, the untargeted nature of a market-led rollout means that network benefits do not become available until a meter penetration of 20-30% is reached, and then build slowly as penetration grows.

As well as positioning to realise network benefits from a market-led smart meter roll out in the long term, we also propose to install telecommunications modules to a subset of our own smart-capable meters in a targeted program. The primary benefit we are seeking is to establish a capability to actively monitor power quality across those areas of the LV network where we face emerging power quality issues in the 2015-20 period. The sections that follow set out how we propose to use smart meters as a key element of our overall plan for power quality management, and why we cannot rely on a market led roll-out of smart meters to address this particular need.

5.1 Power quality

SA Power Networks has an obligation to maintain supply voltage at customer premises within the range specified in AS60038. Historically, this has been achieved without any active monitoring of voltage in the LV network; in a one-way distribution network, voltage at the customer premises can normally be estimated to the required accuracy from known voltage at a major upstream network asset like a substation. We have so far employed a reactive approach to managing occasional customer power quality issues, in which we deploy temporary local monitoring in the LV network in areas where customers have raised complaints about power quality, and this has served us well.

Today, however, we operate a two-way grid, with more than 160,000 small-scale intermittent generators in the form of rooftop solar PV systems connected at the LV network. This is causing significant localised swings in voltage that cannot be detected at the substation. As the penetration of distributed energy resources continues to rise, there is the potential for voltage excursions outside of the allowed range across many parts of the network in the near future.

In this environment, a reactive approach is no longer prudent. If we are to continue to enable customers to connect solar PV and other embedded generation to the LV network and export energy to the grid while maintaining power quality standards, we need the capability to actively monitor power quality (PQ) in the LV network.

In order to assess the potential extent of this issue, SA Power Networks engaged consultant PSC in 2014 to model the impact of increasing penetration of solar PV and other distributed energy resources on quality of supply at the customer premises [25]. The study modelled fifteen typical feeders representing a cross-section of categories of supply area including underground LV, overhead LV and SWER, and applied the findings to estimate the likelihood of future power quality issues across the whole network.

The PSC study found that across older areas of the LV network, existing network infrastructure and voltage regulation approaches limit acceptable solar PV penetration to around 25% of customers.

Currently, the penetration of solar PV is more than 22% of all households, and is forecast to rise further to 40% by 2020 and more than 50% by 2025 [9]. These forecasts are for penetration averaged across the network; penetration in a local feeder area can be significantly higher. PSC's findings indicate that many older feeders are already reaching saturation in terms of acceptable solar PV penetration and, without improved voltage regulation, many parts of the network may be unable to accommodate forecast increases in solar PV during the 2015-20 period without triggering widespread customer power quality issues. These may include customer-visible fluctuations in voltage, increased failure rate of customer appliances, and customers' solar inverters tripping off the network due to overvoltage on mild sunny days, reducing the benefits they receive from feed-in tariffs.

PSC's study also examined mitigation strategies, concluding that:

> *"HV substation voltage regulation can be used, in most instances, to overcome voltage regulation issues provided that the voltage regulation range of the LV network is known.*
>
> *Changes to transformer tap settings (where available) or reconductoring feeder backbones may be sufficient to enable substantial increases in acceptable DER penetration levels.*
>
> *Feeder load balancing and controllable load are also effective, provided that the HV voltage can be kept in the lower half of its usual range – that is, (i) the full LV network operates at a lower voltage, and (ii) the HV voltage is managed to avoid introducing voltage regulation violations under peak demand."* [25]

The modelling indicates that in many cases power quality issues can be mitigated by relatively simple means, e.g. voltage regulation at zone substations or tap changes at transformers, but the key element that is missing today is any visibility of actual power quality across the vast majority of the LV network. Although we may have the means to address issues, we are effectively blind to where those issues are emerging until such time as customers call in to complain. Moreover, without a way to monitor power quality at the premises we have no means to close the loop and measure the effect of any remedial action to confirm that it has been successful.

5.2 Monitoring power quality

In response to these emerging issues, in the 2015-20 period, SA Power Networks proposes to undertake a number of initiatives to deploy grid-side monitoring devices installed at LV transformers, SWER lines and substations, to improve capacity planning and power quality management across a number of areas of the network, in particular in rural areas.

Full details of the overall program of work for quality of supply and LV capacity planning can be found in the relevant Asset Management Plan [17]. In summary, the following grid-side monitoring initiatives are proposed for the 2015-20 period:

- A metropolitan transformer monitoring initiative focused on improving capacity planning and power quality management in metropolitan areas by enabling monitoring at 635 large pad-mount transformers.
- A project to install permanent monitors at start and end of 370 rural SWER lines.
- A project to install monitoring at end-of-line (EOL) transformers for 460 specific 11kV country feeders where there is limited SCADA monitoring today, as well as 65 HV monitors at non-SCADA country substations.
- A project to install monitoring at 85 metro transformers in areas that have more than 20% solar penetration today.

These grid-side monitoring initiatives will establish permanent end-of-line capacity and power quality monitoring in rural areas of the network, as well as addressing some immediate problem areas where high solar penetration is already causing increased volumes of customer complaints. However, these initiatives will focus primarily on the power quality at the extremities of the HV network and provide only limited direct visibility of the LV network itself.

5.3 Meters as a platform for broad-based PQ monitoring

As the broader population of smart-capable meters grows under our new and replacement program, we acquire, over time, a fleet of end-point telemetry devices distributed across the state that can be enabled specifically for remote power quality monitoring at low cost. We propose to take advantage of this opportunity by installing telecommunications modules in meters for PQ monitoring for a selected subset of new and replacement meters each year.

Through this process we will progressively build a new, broad-based monitoring capability that will extend across the urban LV network, at lower cost than installing additional grid-side monitoring devices. These meters will form a key part of the overall platform that will enable the ongoing management of power quality through 2020 and beyond. While we will use grid-side monitoring to target specific areas with immediate issues, particularly at the start and end of HV feeders and at the transformers feeding LV sections, the progressive deployment of communications-enabled meters will establish, through the 2015-20 period, the broad-based monitoring platform we require to manage power quality issues across the urban LV network over the long term.

Our proposed approach is as follows:

- We will target the 17,000 largest (in terms of customer numbers) LV transformer areas that between them account for ~87% of our total customer base. The remainder of the network is characterised by a large number of LV feeders that each serve fewer than 10 customers, where it will be more effective to deploy targeted monitoring on a case-by-case basis.
- 6,514 of these areas have predominantly newer underground cable, where PSC's modelling does not predict significant power quality issues. These will be excluded, along with 44 transformer areas that are included in other transformer monitoring programs. This yields a final target of 10,442 urban transformer areas.
- In our target areas we will aim to establish meter-based monitoring at three customer premises per LV feeder (mid-point and two extremes). This will give enough data points to effectively monitor LV network performance[11], detect and validate power quality issues for the feeder, and potentially, provide data to feed back to upstream voltage regulation devices to enable closed loop control.
- We will select customers with 3-phase meters as these will enable us to monitor all three phases at each end point.
- Whenever a regular meter replacement occurs in one of our target transformer areas and the location is deemed to be suitable for end-point monitoring according to the above criteria, we will install a telecommunications module (unless the customer explicitly declines to have a module installed). In this way we will progressively add end-points to the network-wide monitoring platform at the least possible cost.

[11] Noting that multiple data points per LV feeder are required so that local variations due to customer mains issues can be factored out. While we anticipate that three points per LV feeder will be appropriate in the majority of cases, the requirement may vary for some feeders due to local factors.

Based on the current proportion of three phase meters across our customer base, we anticipate that ~15% of the new and replacement meters installed each year will be candidates to be enabled as PQ monitors. This gives an installation rate of 10,000 telecommunications modules per annum, which will achieve our goal of 3 monitoring points per LV feeder across all urban overhead network areas by the end of 2021, at which point we will have active PQ monitoring at approximately 63,000 locations, or 7% of customer premises.

5.4 Outcomes

If we are to continue to meet customer expectations and regulated power quality standards through the 2015-20 period and beyond, we require the capability to actively monitor power quality throughout the LV network. Without this we will be unable to adapt the network to meet customers' evolving needs, and may need to limit the further integration of distributed energy in order to protect quality of supply for all, curtailing customers' ability to participate more actively on the demand side of the energy market.

By taking advantage of the opportunity created by smart-ready meters to enable broad-based power quality monitoring at low cost, we will achieve the level of visibility we require to enable our future role as the coordinator of the two-way grid at minimal cost to customers.

5.5 Other operational benefits

Our proposed approach will also enable other operational benefits. Wherever a telecommunications module is installed for power quality monitoring, we will enable the following additional functions, as appropriate, in order to maximise the benefit from the meter:

1. Load control
2. Last gasp / service restoration alerts
3. Remote disconnect / reconnect
4. Remote ping

Note that these are the same functions that we intend to enable for third-party meters through the development of interfaces to the AEMC's proposed common market gateway (see section 4.3). The costs to implement and integrate the IT systems and business processes to enable operational benefits from these functions have already been considered in section 4.3 in the context of third-party smart meters. By enabling these same functions when we enable our own meters with telecommunications for power quality monitoring, we gain early access to some of these benefits in advance of widespread availability of third-party smart meters.

To the extent permitted by the Rules, we may also enable remote reading of accumulation or interval data where operational difficulties or other circumstances dictate.

The savings that arise from the operational efficiencies these functions will enable will offset a portion of the future operating costs of the power quality monitoring platform. This is discussed further in section 5.7 below.

5.6 Cost impacts

5.6.1 Unit cost impact

The average incremental cost to provision a 'smart ready' meter will the optional telecommunications module at the time of installation is $238, as shown in Table 14 below.

Meter cost	Meter	Comms module	Antenna	install	Total	Note
Average smart-ready, no comms	153			94	**247**	
Average smart-ready with 3G comms	153	166	33	129	**481**	(1)
Average incremental cost					**234**	

Table 14 – Incremental cost to enable meter telecommunications

Notes:

1. The cost of the telecommunications module, antenna and installation can vary considerably depending on the telecommunications technology used. For the purpose of this business case we have assumed that we will use a public 3G network for communications. Alternative communications solutions are discussed in section 5.8.2.
2. Average meter and installation costs are based on current proportions of different meter types, as described in section 3.5.1.
3. Costs are in 2014 dollars and CAPEX estimates include handling and stores costs. The figures do not include corporate overheads or contingency.

5.6.2 CAPEX impact

We propose to install ~10,000 telecommunications modules per annum on average through the 2015-20 period for network purposes, which equates to ~15% of all new and replacement meters being equipped with telecommunications at the time of installation. The actual number of modules installed will vary year-on-year as they will be installed on a selective basis where they can deliver the greatest benefits, as outlined above.

Table 15 and Table 16 below show the capital costs associated with the proposed selective deployment of telecommunications modules and the associated backoffice IT systems to configure and manage these communications-enabled meters.

CAPEX meter communications modules	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20
Meter comms modules – 3G, installed	$11,694	2,339	2,339	2,339	2,339	2,339
Total meter module CAPEX	**$11,694**					
Quantity installed per annum		*10,000*	*10,000*	*10,000*	*10,000*	*10,000*

Table 15 – CAPEX impact: meter communication modules

CAPEX IT costs to support comms-enabled meters	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20	Note
Backoffice systems implementation and integration	$3,184	2118	1066	0	0	0	(1)
Software licenses	$1,512	979	489	0	0	44	(2)
Servers and hardware	$1,012	536	179	0	0	297	
Implementation program management	$856	0	357	499	0	0	(3)
Security systems	$130	0	11	119	0	0	
IT network upgrades inc. SAPN-PowerCor link	$148	148	0	0	0	0	
Remote energisation/disconnect systems	$924	0	462	462	0	0	(4)
Business process change	$1,227	1227	0	0	0	0	
Total IT / backoffice systems CAPEX	**$8,993**	5008	2564	1080	0	341	

Table 16 – CAPEX impact: IT costs to support communications-enabled meters

Notes:

1. Estimate includes systems implementation and integration for development, production and test environments, commissioning and testing. Estimates have been prepared by Deloitte for IT, drawing on experience from the Victorian AMI program. A detailed cost breakdown is provided in the associated IT costing paper; refer Appendix D for details.
2. Software license costs based on licensing two environments (production and test/DR) at $10 per endpoint based on average vendor per-endpoint volume pricing at proposed volumes of up to 100,000 devices.
3. Estimate includes cost to establish new team, facilities and processes for ongoing operational support, including field support, testing, certification and device firmware configuration management.
4. Note that this estimate is to implement internal systems and business processes to enable remote disconnect/reconnect for the meters that are enabled with communications under the PQ monitoring program, to gain additional operational savings for these meters. This is separate to the future cost of managing incoming disconnect/reconnect events for third party meters via interfaces to AEMC's proposed market gateway, which were considered in section 4.4.
5. IT estimates as shown are in 2014 dollars and include departmental overheads and contingency according to standard methodology for IT cost estimation.

5.6.3 OPEX impact

Table 17 and Table 18 below show the operating costs associated with the proposed selective deployment of telecommunications modules and the associated backoffice IT systems.

OPEX 3G comms modules	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20	Note
Carrier 3G data costs	5,400	360	720	1,080	1,440	1,800	(1)
Total telecommunications OPEX	**$5,400**						
Cumulative modules per annum		*10,000*	*20,000*	*30,000*	*40,000*	*50,000*	

Table 17 – OPEX impact: meter telecommunications

OPEX IT costs to support comms-enabled meters	Total 15-20 ($,000)	2015-16	2016-17	2017-18	2018-19	2019-20	Note
Meter test and certification group	$1,279	0	0	149	479	651	(2)
Backoffice support – new meters	$618	124	124	124	124	124	(3)
Backoffice support – active meters	$1,361	247	247	247	247	371	(4)
Technical field staff (meter comms)	$1,384	252	252	252	252	378	(5)
IT systems support and maintenance	$998	85	201	232	240	240	(6)
Backoffice software vendor support costs	$1,321	83	248	330	330	330	(7)
Total IT / systems support OPEX	**$6,961**						

Table 18 – OPEX impact: smart meter support costs

Notes:

1. 3G data costs assume 10,000 modules p.a. at $36 p.a. (estimate $3 p.m. for 1MB plan at proposed volumes)
2. Test & certification group staff, inc. firmware configuration management. Estimate 3 FTE in year 2, 5.5 FTE in years 3 and 4 and 7 FTE in year 5.
3. 1 FTE to support ongoing commissioning and setup of new meters in backoffice systems assuming 10,000 p.a. during deployment phase
4. 2 FTE + 1 FTE per 50,000 active meters to provide backoffice support and maintenance for active meters in the field, ongoing
5. 2–3 FTE technical field resources to assist with non-standard installations, troubleshooting and telecommunications issues during deployment phase
6. IT support and maintenance, servers, network devices and other hardware, security systems, communications gateways and links.
7. Software support and maintenance at 20% of license cost p.a.
8. IT systems OPEX estimates have been prepared with assistance of Deloitte, drawing on experience from the Victorian AMI program. A detailed cost breakdown is provided in the associated IT costing paper; refer Appendix D for details.
9. Estimates as shown are in 2014 dollars. IT costs include departmental overheads and contingency according to standard methodology for IT cost estimation.

5.7 Net cost/benefit

While there will be a net cost associated with enabling meters for remote power quality monitoring, a portion of the future operating cost will be offset by operational efficiency savings and other benefits arising from other meter functions such as remote disconnect/reconnect and last-gasp alarms.

As discussed in section 4.5, previous studies that have quantified the network benefits of smart meters have considered either a 100% rollout scenario, e.g. the Deloitte 2011 review of the Victorian rollout [21] or an untargeted, market-led rollout, e.g. the 2014 Energeia study [27]. Being limited to a maximum of only 7% meter penetration, our proposed deployment falls below Energeia's threshold for benefits realisation in an untargeted rollout. Our approach is, however, highly targeted to deliver three 3-phase meters per LV feeder in our nominated areas. This distribution of end points is also well suited to maximising the benefits available from functions such as last-gasp alarms at low meter penetration.

SA Power Networks engaged Deloitte to assist in developing estimates of the future operational savings arising from these benefits in our proposed 'sparse but targeted' deployment. The estimated value of these benefits over time[12] is summarised in Figure 12 below. Full details of the estimation methodology are provided in Appendix E.

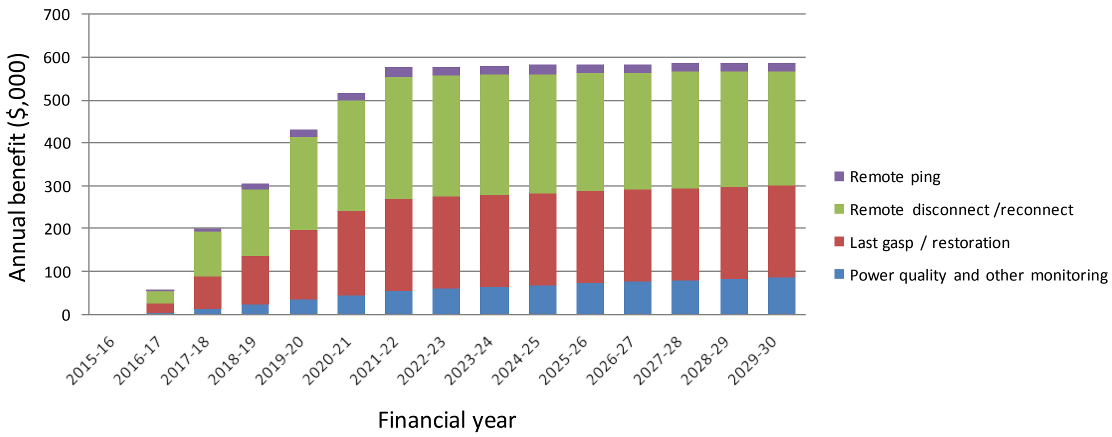


Figure 12 – per-meter operational benefits escalation

In all, we estimate modest benefits of approximately $600,000 p.a. from 2022 attributable to consequential operational benefits available from our telecommunications-enabled meters, for a total benefit (15 year NPV) of $3-4 million.

Taking these benefits into account, the estimated net cost per annum of the program over 15 years is as shown in Figure 13 below. The total estimated cost is $46.3 million NPV.

12 Figures are 2014 dollars and do not include any escalation.

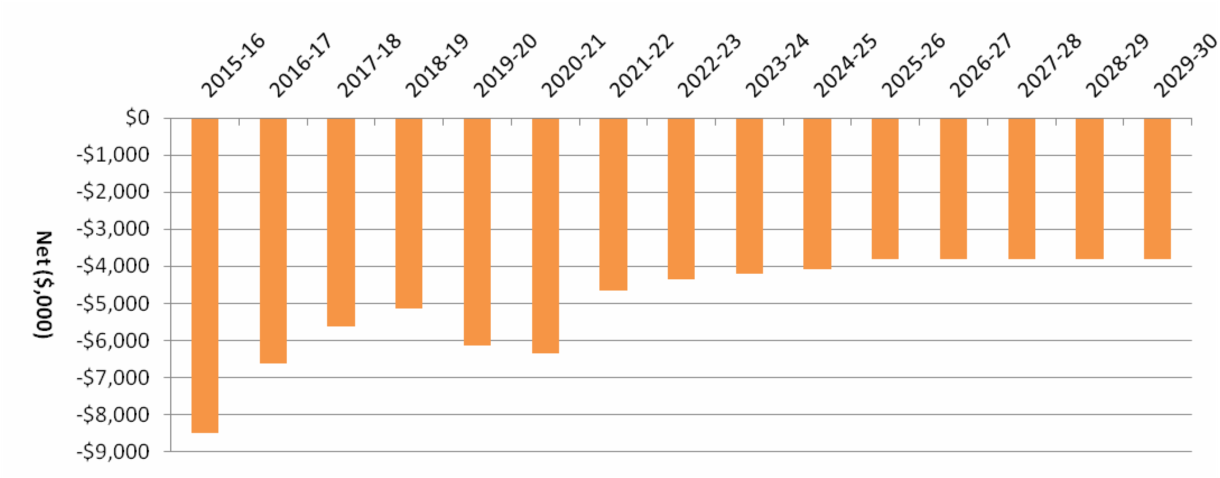


Figure 13 – estimated net cost per annum (CAPEX + OPEX)

5.8 Alternative approaches

We have considered two other options to establish active PQ monitoring across our target areas of the LV network:

1. Implement grid-side monitoring using pole- and pad-mounted devices outside the customer premises
2. Implement meter-based monitoring using an alternative telecommunications technology (RF mesh).

These are outlined in the sections below.

5.8.1 Option 1: grid-side monitoring

We have examined the cost to implement an alternative grid-side monitoring solution using dedicated devices installed on each LV feeder in our target areas, instead of using communications-enabled meters.

We have estimated the cost of this approach as follows:

- We would install two grid-side monitors per LV feeder in each of the target transformer areas, at the start and end of the feeder. While this will not give as many sample points as the three meters per feeder proposed under our preferred option, we believe two grid-side monitors would be sufficient because (a) this approach allows for devices to be located optimally on the feeder and (b) there is no requirement to factor out potential measurement errors due to customer-side faults.
- We have allowed for an average installation rate of 3,000 devices p.a., to complete the installation phase within the same timeframe as in the meter-based approach. The total number of devices to be installed by 2021 would be 20,884.
- Per-unit cost is $3,185 per device on average, including field installation costs. This assumes the same grid-side monitors as specified for other transformer monitoring initiatives, or equivalent. Devices will be predominantly pole-mounted, and start-of-feeder devices will be co-located with the LV transformer where possible. For a detailed unit cost breakdown refer to the LV network Asset Management Plan [17].
- Backoffice IT systems and operating costs are assumed to be equivalent to the meter-based solution, with software licensing costs, support FTEs and other costs scaled to reflect the smaller number of devices to support.

- Telecommunications costs are assumed to be $8 per month per device, based on applying a volume discount factor to rates estimated for other transformer monitoring initiatives. Compared to the meter-based approach, grid-side monitoring has fewer end-points but typically higher per-device data volumes.

The estimated net cost (15 year NPV) of this option is significantly higher that our preferred meter-based approach, at ~$86 million, as shown in Figure 14 below. This is because the per-unit capital cost of field equipment is higher, and the additional operational savings that can be achieved through smart meters are not realised.

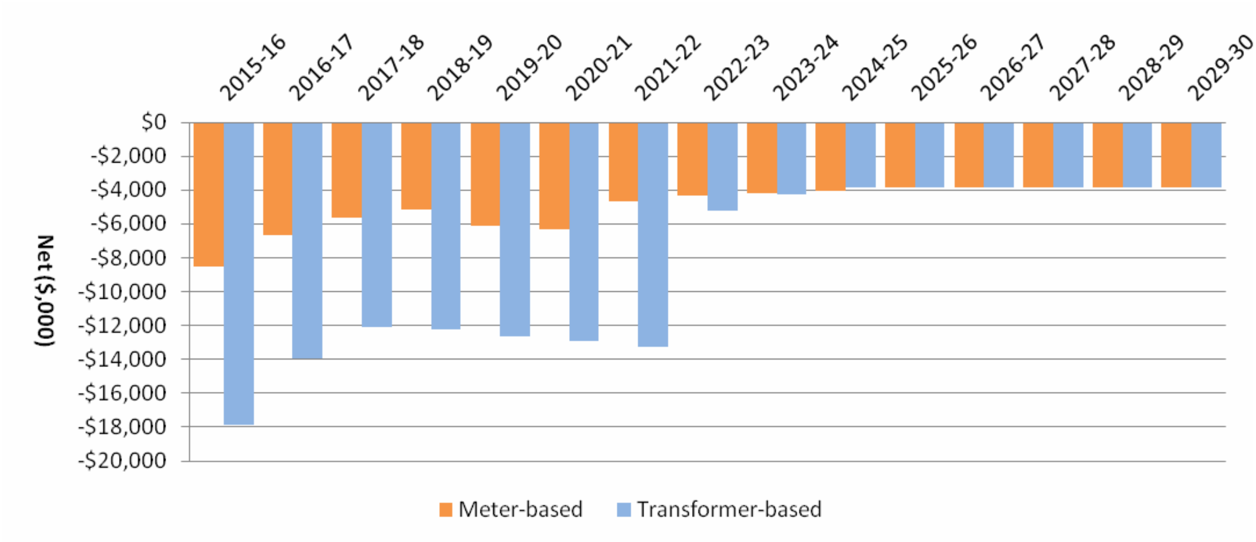


Figure 14 – meter-based vs. grid-side cost comparison (CAPEX + OPEX)

5.8.2 Option 2: alternative communications technology (mesh radio)

For the purpose of this business case we have assumed that our communications-enabled meters will use a carrier 3G network for communications. We have also considered mesh radio, as used by four of the five networks in Victoria, as a communications platform.

Although the Victorian experience has shown that mesh radio is a cost-effective solution for meter communications in a full rollout scenario, mesh radio infrastructure cost is only justified when there is a reasonable population of meters in a given area, with the break-even meter density estimated at between 15% of households (urban) and 30% (rural)[13] under current pricing [22]. Although our proposed replacement schedule would result in this kind of meter density in urban areas around the start of the 2020-25 period, as noted above, it is possible that we may be able to scale back our own deployment and use third-party meter providers for the services we require in some areas towards the latter part of the 2015-20 period. A solution based on 3G communications will provide the greatest flexibility, and is considered prudent given the level of uncertainty around the future impact of metering contestability on our plans.

We may re-examine some use of mesh radio on a targeted basis to the extent that a positive business case can be demonstrated. To this end, field trials are currently underway to validate mesh performance and refine metropolitan infrastructure cost models in a sparse rollout scenario based on our projected meter density.

[13] Rural areas have lower population density and more challenging terrain from an RF perspective and hence require more infrastructure devices per meter.

5.8.3 Summary of options

In summary, our preferred approach to developing a platform for power quality monitoring across the LV network using customer meters enabled with 3G communications is preferred over the two other options considered because:

- The total cost (NPV) will be significantly lower than a grid-side monitoring approach (option 1)
- The cost efficiencies achieved in Victoria using mesh radio (option 2) for meter communications are unlikely to be realised at proposed meter densities, and there are additional commercial and technical risks associated with this approach.

The other key benefit of our meter-based approach is that it is readily extensible to incorporate power-quality and other data streams from third party meters in future, as discussed below.

5.9 Use of third party meters

As described in section 4.5 we expect, in future, to be able to access power quality data from third party meters via the proposed common market gateway, assuming a market-led smart meter rollout resulting from the metering contestability rule changes.

We do not expect that the proposed new market rules will come into force until mid-way through the 2015-20 period. Moreover, we cannot control the rate of uptake of smart meters under a market-led rollout, nor their location on the network. For these reasons, we cannot rely on the proposed contestable market to deliver the capability we require in terms of power quality monitoring in the timeframe we require it, hence we propose to develop our core monitoring capability through our own communications module deployment plan. In the longer term, however, assuming a market-led rollout progresses and penetration grows, integrating data from third-party meters will progressively improve the reach and accuracy of our monitoring platform.

It is possible, if the market develops rapidly, that third party meter providers could be in a position to offer the services we require in the 2015-2021 timeframe. This being the case, we would seek to purchase access to these services via the AEMC common market gateway and avoid the cost of installing further communications devices to our own meters, if it were efficient to do so. Any associated savings would accrue to customers in subsequent regulatory periods.

6 TIMELINE

A high-level timeline for the initiatives set out in this business case is shown in Figure 15 below.

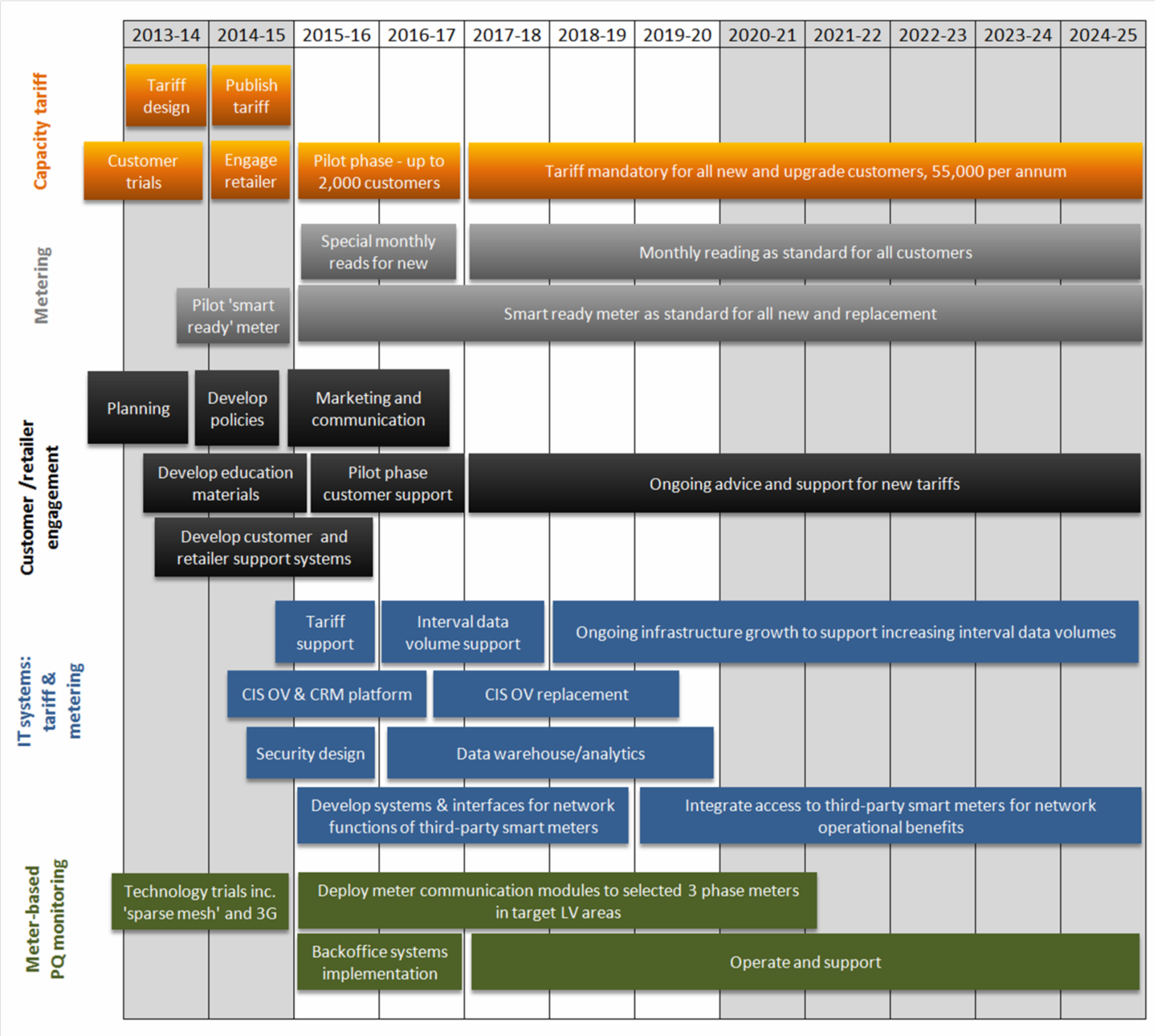


Figure 15 - Timeline

7 SUMMARY OF COSTS

In summary, our proposed tariff and metering program has the following cost components in the 2015-20 period:

- **new meters that can support our tariff,** phased in through our new and replacement rollout schedule, and monthly meter reading for all customers from July 2017 (see section 3)
- **new IT systems** to enable the tariff, and to process the increased volumes of data from smarter meters, both those we install and those that third parties install that we access through the market gateway (see sections 3.5.4 and 4)
- **customer and retailer engagement** to support customers through the transition to our new network tariff (see section 3.6)
- **telecommunications modules and associated systems** for a subset of the meters we install, to enable power quality monitoring and other operational benefits (see section 5).

7.1 CAPEX summary

The total capital cost for 2015-20 is shown in Table 19 below and the chart that follows. The table also shows the indicative allocation of costs to Standard Control Services (S) and Alternative Control Services (A). This is discussed further in section 7.3 below.

CAPEX	Cost ($M)	SCS/ ACS	2015-16	2016-17	2017-18	2018-19	2019-20
Base IT systems - tariff & contestability	20.1	S/A	1.7	1.8	9.7	5.1	1.9
Customer/retailer engagement & tariff implementation	5.8	S	3.	2.7	0.0	0.0	0.0
Meter communications IT systems	9.0	S	5.	2.6	1.1	0.0	0.3
Meters - smart ready, new and upgrade	13.4	A	2.	2.8	2.9	3.1	1.9
Meters - comms modules	11.7	S	2.	2.3	2.3	2.3	2.3
Total	**59.9**		**14.9**	**12.2**	**15.9**	**10.5**	**6.5**

Table 19 – CAPEX summary

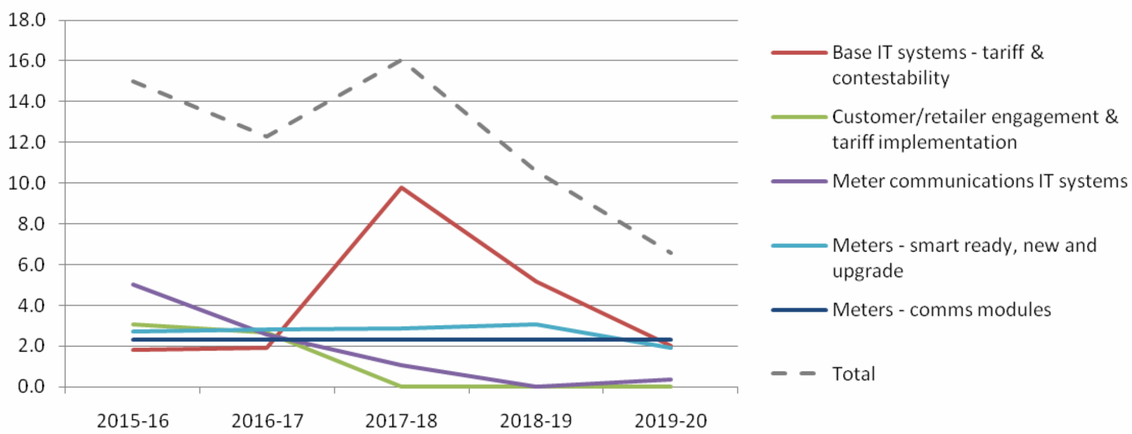


Figure 16 – CAPEX spending profile

Notes:

1. CAPEX for ‘Base IT systems – tariff & contestability’ includes the cost to support the new tariff within our existing systems (refer Table 7 in section 3.5.4) and the cost to upgrade IT systems to support a broader uptake advanced metering (refer Table 11 in section 4.4).
2. CAPEX for ‘Meters – N & R’ shown above is the incremental cost associated with the new and replacement metering program when compared to a BAU assumption in which we continue to install the type 6 meters we install today (refer to section 3.5 above for details). All other costs are new costs.

7.2 OPEX summary

Table 20 and the following chart show the total impact on operating cost for the 2015-20 period. The indicative allocation of operating costs to Standard Control Services (SCS) and Alternative Control Services (ACS) is also shown.

OPEX	Cost ($M)	SCS/ ACS	2015-16	2016-17	2017-18	2018-19	2019-20
Base IT systems - tariff & contestability	3.7	S	0.0	0.5	0.9	1.1	1.2
Customer/retailer engagement & tariff implementation	11.9	S	0.0	1.6	3.2	3.5	3.6
Meter communications IT systems	7.0	S	0.8	1.1	1.3	1.7	2.
Meters - meter reading / data processing	36.4	A/S	0.1	0.2	11.7	12.0	12.4
Meters - comms modules - communications	5.4	S	0.4	0.7	1.1	1.4	1.8
Total	**64.4**		**1.3**	**4.0**	**18.1**	**19.8**	**21.2**

Table 20 – OPEX summary

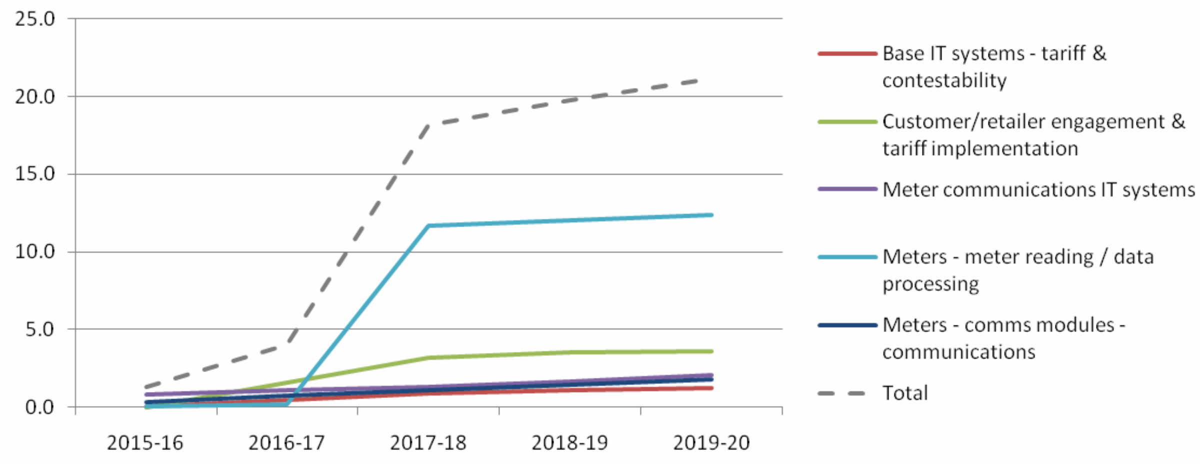


Figure 17 – OPEX spending profile

Notes:

1. OPEX for ‘Base IT systems – tariff & contestability’ includes the cost to support the new tariff within our existing systems (refer Table 8 in section 3.5.4) and the cost to upgrade IT systems to support a broader uptake advanced metering (refer Table 12 in section 4.4).

2. OPEX for 'Meters – meter reading / data processing' shown above is incremental cost associated with meter reading and data processing across all customers when compared to a BAU assumption in which we do not introduce new tariffs. The step change in 2017 reflects the transition to monthly meter reading for all customers associated with the main launch of the tariff, as detailed in section 3.5 above. All other costs are new costs.

7.3 Cost recovery: Standard Control Services and Alternative Control Services

All costs in this business case are for regulated services, and for cost recovery we propose to classify the cost components as follows:

- **New meters:** 'smart ready' meters, installation costs, monthly meter reading costs and other metering opex will be funded through our regulated metering charges as Alternative Control Services, in line with current practice. Note that under the AER's Framework and Approach paper [23], both type 5 and type 6 metering services will be classified as ACS in the 2015-20 period.
- **Upgraded IT systems:** We require upgrades to our backoffice IT systems to process the richer data sets available from smarter meters. This is necessary expenditure in the 2015-20 period and the cost is fixed irrespective of how metering contestability unfolds.

  As prudent operators we must upgrade our IT systems to the standard reasonably required to cope with the anticipated increase in interval data, to implement interfaces to the proposed common market gateway, and to put in place the basic systems and interfaces (e.g. to ADMS and OMS) required to unlock the network benefits that become available as the population of smart meters grows.

  These costs are required for network billing, network management and customer support, and are thus Standard Control Services expenses.
- **Customer and retailer education & support** through the transition to our new network tariff will be classified as a Standard Control Service; we intend to introduce our tariff irrespective of whether the required meters end up being installed as a regulated service or by the contestable market.
- **Telecommunications modules and associated backoffice IT systems:** as these modules are installed for network purposes, all associated capital and recurrent costs will be classified as Standard Control Services.

7.4 Replacement of 'smart ready' meters by other providers

Under the proposed contestable market a retailer or customer may choose to appoint a third party meter provider. In this case we expect that:

- an exit /transfer fee (or equivalent) would apply
- we would no longer charge the regulated metering charge for that customer
- our regulated meter would potentially be removed and replaced with the third party meter.

The final rules around the displacement of regulated meters under the new market arrangements will not be known until the contestability rule change process is complete. The rule change proposal recognises that networks must be 'kept whole' when regulated assets are displaced, through exit fees or an equivalent method such as transfer of residual asset value to the SCS RAB. The rule change proposal also notes that existing load control functionality must be preserved if a network meter is replaced, and the ENA is proposing that networks should have the right to retain their own meter alongside the new meter if they cannot agree a satisfactory arrangement to access equivalent functions with the new meter provider.

Under our proposed approach to metering, we anticipate that:

- If a regulated meter is removed from a customer who has a controlled load, then the incoming meter provider will be required to provide equivalent or better load control functionality at the site via the AEMC common market gateway.
- On payment of the appropriate transfer fee (or equivalent), ownership of the 'smart ready' meter asset will transfer to the incoming meter provider, should they choose. The new provider could then retain the meter and retro-fit their own telecommunications module to integrate with their own backoffice systems rather than replacing the whole meter. This would have the following benefits:
    - The incoming meter provider would avoid the cost of a new meter
    - The incoming meter provider would avoid the cost of meter removal and reinstallation
    - The meter could be changed without the need for a customer supply outage; this can be a significant benefit to some customers, especially business customers.
- If our meter had a telecommunications module installed for network monitoring, we would seek access to the same data from the new provider via the AEMC market gateway. We would recover the communications module as this would remain in the SCS RAB (it would not transfer to the incoming meter provider) and we could potentially re-deploy it in another meter.

8 RISKS

There are specific commercial, operational and technical risks associated with our proposed approach to tariffs and metering. These are summarised at a high level in the table below.

No.	Risk	Detail and consequences	Mitigation
1	**Tariff take-up greater than forecast**	Because we have a price cap for Alternative Control Services [23], if more customers take up the tariff than forecast then ACS revenue in the period will not be sufficient to cover operating costs. This risk is most significant in the two years prior to the transition to monthly meter reading as standard, when per-customer read costs for customers opting-in to the tariff are high.	Use expert consultants and best-practice methodology for forecasting: Energeia (solar/DER uptake), BIS Shrapnel (new customer connections), UMR (voluntary opt-in). Limit active promotion of tariff in years prior to standardisation of monthly meter reading
2	**Type 6 metering solution is un-proven in SA**	There are technical risks associated with supporting the tariff with a type 6 meter with capacity registers, as there is no precedent for this in SA. The cost to implement the systems changes could be higher than forecast; vendor lead-times for implementing product changes could cause delays; and some retailers may face technical issues with their billing systems.	Advice from meter vendors is that the similar capacity registers are already supported in modern meters. Some precedent for similar solutions interstate (e.g. Networks NSW implements a ToU tariff using 'ToU registers' in a type 6 meter).
3	**New tariff could provoke customer backlash**	Customers who perceive themselves to be losers under the new tariff may seek to oppose it through consumer action.	Allow sufficient resources to manage customer experience through a comprehensive customer engagement and education plan, as detailed in section 3.6.
4	**Network and/or customers impacted by cyber-attack on our meter communications network**	We are proposing to enable meters with the capabilities of remote disconnect and remote load switching. A malicious attacker that was successful in gaining access could potentially trigger widespread customer disconnection or mass load switching, causing outages and potential local network instability.	Budget allows for the implementation of robust IT security systems (refer section 4.4)

No.	Risk	Detail and consequences	Mitigation
5	**Resource and/or timing conflicts with other IT projects e.g. CIS O/V upgrade**	IT is managing a complex program of work through the 2015-20 period, and the changes proposed herein have dependencies and interactions with other planned system upgrade and maintenance projects.	Deloitte and IT have sought to take this into account when preparing cost estimates for this business case, but advise that there is a level of residual risk.
6	**Three meters per LV feeder may not be sufficient in some transformer regions**	Local factors including the length of the LV feeder, distribution of solar PV and other DER and the location of candidate premises for meter-based monitoring could mean that additional meters are required in some areas to achieve adequate power quality measurement.	May require additional investment to augment the platform during 2020-25 period. Exposure is limited by low per-unit cost of meter-based monitoring. Third-party smart meters may also be available in 2020-25 period as additional monitoring points.
7	**Network benefits of third-party smart meters may not be realized**	Network benefits of third-party meters will only be realised if there is an adequate minimum functional specification, well defined common market protocol, and appropriate regulatory framework for access. ENA has concerns that the rule change process may not deliver these outcomes.	SA Power Networks continues to participate actively in AEMC and AEMO processes to advocate for a market model that will enable network benefits.

Table 21 – Risks

9 STRATEGIC ALIGNMENT

Our strategy is intended to facilitate the better achievement of the National Electricity Objective, which is *"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity..."* [13].

The sections that follow briefly review how these initiatives align directly both with the priorities of South Australian consumers, with the key policy objectives that are currently driving reform in the industry, and with the overall strategic goals of the business.

9.1 Alignment with customer priorities

In 2013, SA Power Networks conducted an extensive stakeholder consultation program, *TalkingPower™*, which included seven workshops held with customers and other stakeholders across the state, and an on-line survey [11]. Facilitated by Deloitte, the purpose of the *TalkingPower™* program was to engage with customers and other key stakeholders on their concerns and needs, to inform the future priorities for our business.

This business case aligns directly with the following key customer insights distilled from the *TalkingPower™* engagement [29]:

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#10 Consider installing advanced meters

Customers support the adoption of advanced meters to give them greater control over their electricity usage. In fact, 78% of customers surveyed supported the installation of a smart meter in their home or business.

#11 Continue upgrades to support a two-way network.

Almost universally, customers favour upgrades to enable a two-way network to support the increasing uptake of new technologies.

#12 Develop cost-reflective pricing tariffs.

68% of customers are in favour of developing and phasing-in socially equitable cost-reflective pricing strategies.

#13 Educate customers about new technology and industry change to help increase their satisfaction.

Customers clearly expressed a need for education on new technologies and changes to the industry.

Customers also cited "hardening the network against lightning and storms" as one of their top three community safety and reliability priorities [29]. Our capability to diagnose and respond to structural damage in the LV network as a result of events such as the severe storm that caused extensive power outages in the eastern suburbs in February 2014 will be enhanced through our proposed deployment of communication-enabled meters.

9.2 Alignment with the views of the SA business community

Our tariff strategy, our 'new and replacement' approach to minimising the cost of the associated transition to more advanced metering, and our strategy to maximise available 'smart grid' benefits whenever meters are enabled with telecommunications, all align with the views of the South Australian business community as expressed though South Australia's Chamber of Commerce and Industry, Business SA.

Business SA has long advocated for smarter meters in SA [44]. In a survey of members prior to the last State election, they found that *“80% of respondents supported a rollout of smart meters”* while noting that *“it will be critical that the transition to smart meters is managed to minimise any additional cost on business, particularly small business.”* [44]

In a written submission in response to the SA Government’s new and replacement policy proposal [44], Business SA wrote:

> *“Business SA supports the intent of the State Government’s proposed smart meter policy in so far as it advances the development of a smart electrical grid in South Australia...It is also important that small customers, including small businesses, are given access to innovative tariff offerings which will only come through the introduction of smart meters*
>
> *“Given a significant number of traditional accumulation meters need replacing every year regardless, it is only logical that such meter replacements are now made with smart ready meters which can be easily retrofitted with communications packs to become smart meters.”*

Subsequently in June 2014 Business SA submitted a written response to SA Power Networks’ *Directions and Priorities 2015 to 2020* paper [45], writing:

> *“We support SAPN’s move towards cost reflective tariffs and enabling new technologies concomitant with the roll out of smart meters and are encouraged that SAPN recognises battery storage as playing a more significant role in the future electricity grid. Business is already pursuing energy efficiency as a first response to rising electricity prices, but it is increasingly important that the right price signals are [sent] to reflect the actual network costs associated with usage at various times.”*

9.3 Alignment with public policy

The 2012 AEMC *Power of Choice* review [2] recommended:

- Networks should adopt cost-reflective tariffs as soon as possible to address cross-subsidy issues. This review advocated time-varying pricing, but noted that *“[maximum] demand charges will still be permitted.”* On the proviso that *“Networks will have new obligations to have regard to consumer’s understanding of such charges and their ability to respond.”*
- “*Continued installation of accumulation meters today will lead to increased costs for the consumer and system costs in the long term.”* The review also noted that the current rules prevent networks from installing smarter meters under their regulated metering services and this should be addressed
- smart meters should be mandatory for all new and replacement installations for larger domestic customers, and all future metering installations should conform to the SCER-endorsed Minimum Functionality Specification
- all metering should be contestable, with retailers assuming the primary responsibility for eliciting consumer opt-in to a smart meter. However, the review specifically

recommended that *"Network businesses would be able to fund smart meters and additional functionality as part of a network DSP program (regulated by AER)."*

- *"Networks will need to have access to the operational data emerging from smart meters, and also ability to do load control and for network planning and operations"*

The 2013 *Productivity Commission Inquiry report on Electricity Network Regulatory Frameworks* [19] similarly found that:

- *"spiralling network costs in most states are the main contributor to these [price] increases, partly driven by inefficiencies in the industry and flaws in the regulatory environment"*
- cost-reflective network pricing is urgently required to address cross-subsidies (this report favoured Critical Peak Pricing, but SA Power Networks' own research has established that this is not optimal in SA)
- cost-reflective network pricing and smart meters if appropriately deployed could save households \$100-\$200 p.a. *"in regions with impending capacity constraints."* Unlike the *Power of Choice* review, this report strongly favours a network-led introduction of smart meters targeted to constrained areas as the most efficient approach.
- *"weakly-targeted time-of-use tariffs"* would fail to deliver the above benefits.

SCER, in its response to the *Power of Choice* review [7], broadly supported the *Power of Choice* position with the exception that it proposed that new tariffs and new meters should be opt-in only unless individual state jurisdictions decide otherwise.

In January 2014, South Australia's Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE)[14] released a discussion paper proposing that all new and replacement meters installed under the proposed contestable market in SA should, as a minimum, be 'smart ready' type 5 meters, i.e. interval meters that are designed to be upgradable to full smart meter specification [5].

Our proposed approach aligns with these policy directions:

- We agree that is in the public interest for us to transition customers to a cost-reflective network tariff to address increasing inequity as soon as possible.
- We agree with the Productivity Commission that a stronger price signal than ToU is required, and tariffs must be well targeted to be effective.
- We agree with AEMC and DMITRE that it is in the public interest to phase out further spending on inadequate meters that will inevitably require replacement well ahead of their asset life.
- We agree with AEMC and DMITRE that the most efficient (least-cost to consumer) way to introduce new meters is as part of upgrade works (e.g. solar install), scheduled asset replacement or in new premises where a new meter is required in any event.
- We agree with the Productivity Commission that cost/benefit of smart meters is optimised when smart meters are introduced in a targeted way, not in a blanket rollout.
- We are supportive of full contestability for metering services, where the customer can opt to pay a higher metering charge in order to access value-added services and tariffs, but we agree with SCER that consumers should not be forced to pay a

[14] Now Department of State Development

substantially higher metering charge for a smart meter if they did not choose to have one, but had one imposed on them. Hence there is an ongoing need for a basic regulated metering service as the contestable market develops.

Our proposed approach is also consistent with the position we and the ENA have advanced through our formal submissions to the AEMC working group on common communication standards for smart meters [14,15], and our response to DMITRE's discussion paper [5].

9.4 Alignment with National Electricity Rules expenditure objectives

Our proposed approach aligns with the four network expenditure objectives set out in Chapter 6 of the NER, as summarised in [42], as follows:

1. **Meet or manage the expected demand for regulated services over the regulatory control period**

   Effective tariff reform is central to managing the expected demand for regulated services over the next regulatory control period and beyond. By phasing in cost-reflective network tariffs for customers at the point at which they are making investment decisions that will affect their demand on the network, we will encourage choices and behaviours that will increase utilisation of existing networks assets, reducing the need for network augmentation in the long term.

2. **Comply with all applicable regulatory obligations or requirements associated with the provision of regulated services**

   SA Power Networks has a regulatory obligation to maintain power quality at customers' premises to Australian standards. Increasing penetration of rooftop solar PV is causing unprecedented variations in voltage across older areas of the low voltage network. If we are to continue to meet our regulatory obligations in relation to power quality over the next regulatory control period and beyond we require active monitoring at the LV network level in these areas. We propose to achieve this in an efficient way by enabling power quality monitoring on a targeted subset of 3-phase meters.

3. **Where no applicable regulatory obligations or requirements associated with the provision of regulated services exist, maintain the quality, reliability and security of supply of regulated services**

   See above.

4. **Maintain the safety of the transmission or distribution system through the supply of regulated services**

   While this objective is not a primary driver for the initiatives set out in this business case, experience from the Victorian rollout has demonstrated that a transition to smarter metering can deliver a number of safety benefits, for example the detection of degraded neutral at the customer premises, detection of continued energy export from embedded generators during loss of grid supply due to inverter faults, and so on.

9.5 Meeting the National Electricity Rules expenditure criteria

Our proposed approach aligns with the three expenditure criteria set out in the NER, as follows:

1. **the efficient costs of achieving the objectives;**

   Our proposed 'new and upgrade' approach to phasing in new tariffs and new meters targets customers at a time they require a meter replacement in any event. By avoiding the cost of a separate visit to replace a meter or install a grid-side power quality monitoring device we are seeking to achieve our objectives in tariff reform and LV network monitoring as cost-efficiently as possible.

From a system-wide perspective, aligning network pricing to cost will drive more efficient use of network assets, minimising network cost in the long term.

2. **the costs that a prudent operator would require to achieve the objectives; and**

   We consider that the initiatives proposed in this business case are the minimum reasonably required by a prudent operator to meet the needs of customers in the 2015-20 period and beyond. Taking into account the information we have today we consider that it would be *imprudent* to:

   - fail to respond to rising network prices and decreasing network utilisation caused by inappropriate price signals in our current tariffs
   - fail to act to mitigate the predicted emergence of widespread power quality issues as solar PV penetration exceeds the limits of current infrastructure on feeders across all older areas of the LV network
   - continue to install obsolete and non-upgradable accumulation meters that cannot support new tariffs or provide the data customers need to understand and manage their energy use.

3. **a realistic expectation of demand and cost inputs required to achieve the objectives.**

   We have engaged appropriately qualified and experienced industry consultants including Energeia, Deloitte, PSC, Ernst and Young, BIS Shrapnel, UMR and others in order to develop the demand and cost inputs to this business case, using appropriate economic and technical modelling tools and methodologies and taking into account relevant practical experience in other jurisdictions, in particular from the Victorian AMI programs.

9.6 Alignment with corporate strategic objectives

Our proposed approach aligns with SA Power Networks' corporate strategic objectives:

1. **Delivering on the needs of our shareholders, by achieving our target returns, maintaining the business' risk profile, and protecting the long term value of the business**

   Tariff reform is fundamental to protecting the long term value of the business in a future environment of reduced energy consumption, increasing embedded generation and greater demand-side participation.

2. **Providing customers with safe, reliable, value for money electricity distribution services, and information that meets their needs**

   By encouraging and facilitating more efficient use of the network we will increase customer value in the long term. By leveraging new data streams and functions of smart meters we can employ cost-effective strategies to maintain network reliability and power quality in the face of the challenges posed by widespread intermittent distributed generation connected at the LV network.

3. **Maintenance and development of key capabilities that will help sustain our success into the future**

   In 2015-20 we will develop the capability to integrate smart meters, whether operated by us or third-parties, as a key component of the future smart grid.

4. **Energised and responsive customer service**

   Through our investments in customer and retailer engagement, call centre staff and supporting IT systems we aim not only to ensure a smooth transition to new capacity tariffs, but to put in place the people and systems that will continue to engage with customers and respond to their increasingly sophisticated needs into the future as they embrace new demand-side technologies.

5. **Excellence in asset management and delivery of service**

   Through technologies such as meter loss of supply detection and active monitoring at the customer supply point we will improve our capability to respond rapidly and effectively to network faults and other customer issues.

10 SUMMARY

To recap, the key elements of our proposal are:

- a transition to cost-reflective network tariffs based on capacity (peak demand)
- customer and retailer engagement and education, to ensure customers understand the tariffs and have the capacity to respond
- the adoption of a new standard regulated meter that has the minimum functionality required to enable the new tariff, while being fully upgradable to the national Minimum Functionality Specification
- a 'new and replacement' approach to transitioning customers to the new tariff that will minimise the cost to the community
- positioning to ensure the maximum value is realised from a future market-led smart meter rollout by establishing the systems that will unlock network benefits
- the use of smart meters as a cost-effective telemetry platform for broad-based monitoring of power quality at customer premises, to facilitate the ongoing integration of distributed energy resources into the grid.

These initiatives represent a prudent and efficient approach to meeting the challenges of increased demand-side participation, and ensuring that the distribution network continues to meet the needs of customers through the 2015-20 regulatory period and beyond.

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12 GLOSSARY

3G	3rd Generation (mobile phone standard)
AAA	Authentication, authorisation and accounting (information security)
ACS	Alternative Control Services
ADMS	Advanced Distribution Management System
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AP	(mesh) Access Point
B2B	Business-to-Business
BAU	Business As Usual
CaMS	Construction and Maintenance Services
CHED	CHED Services – CitiPower/Powercor metering services provider
CIS O/V	Customer Information System OpenVision
CPI	Consumer Price Index
CPP	Critical Peak Pricing
DB	Distribution (network) Business
DPP	Dynamic Peak Pricing
DER	Distributed Energy Resources
DMITRE	Department for Manufacturing, Innovation, Trade, Resources and Energy (South Australian Government) – renamed in 2014 to Department of State Development (DSD)
DR	Disaster Recovery
DSD	Department of State Development (SA Government, formerly DMITRE)
DSP	Demand-Side Participation
ENA	Energy Networks Association
EV	Electric Vehicle

FTE	Full Time Equivalent (staff)
GSL	Guaranteed Service Level
HAN	Home Area Network
HV	High Voltage
IBT	Inclining Block Tariff
IEE	Itron Enterprise Edition (meter data management system)
IT	Information Technology
kW	kilowatt
kWh	kilowatt-hour
LV	Low Voltage
MC	Metering Coordinator
MD	Maximum Demand
MDP	Meter Data Provider
MMS	Meter Management System
MW	Megawatt
MTS	Market Transaction System
MVRS	Itron MV-RS meter reading software
NDS	Negotiated Distribution Services
NEM	National Electricity Market
NER	National Electricity Rules
NMI	National Meter Identifier
NPV	Net Present Value
OMS	Outage Management System
PQ	Power Quality
PV	Photovoltaic
PTRM	Post-Tax Revenue Model
PSC	Power Systems Consultants

RAB	Regulated Asset Base
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test-Distribution
SAIDI	System Average Interruption Duration Index
SAPN	SA Power Networks
SCADA	Supervisory Control And Data Acquisition
SCER	Standing Council on Energy and Resources
SCS	Standard Control Services
SMETS	Smart Metering Equipment Technical Specifications
SMI	Smart Meter Infrastructure
SWD	Sequential Waveform Distortion (a means of communicating over power lines)
ToU	Time of Use (pricing)
UI	User Interface
UK	United Kingdom

A STAKEHOLDERS

The following key stakeholders were consulted in the preparation of this document, and received the previous draft (draft 0.79a, issued 19th May 2014) for review:

Role / department	Name	Position
Project owner	Alida Jansen van Vuuren	Smart Grid Strategy Manager
Project sponsor	Mark Vincent	Manager Network Investment Strategy & Planning
DSP team	Stephen Webb	Smart Grid Project Manager
	Paul Erwin	Retailer Relations Manager
CaMS	Tom Walker	Manager Strategic Development
	David Oliver	Manager Metering Services
Customer Relations	Andy Gillis	Metering Data Manager
	Mark Evans	Manager Revenue Management
	Colin Grave	Revenue Services Manager
	Cameron Daniel	Acting Manager Customer Response
Corporate strategy, regulation and reset	James Bennett	Manager Regulation
	Grant Cox	Manager Regulatory Affairs
	Chris Rae	Manager Regulatory Strategy
	Wayne Lissner	Head of Regulation
IT	Peter Chapman	Business Analyst
	Jason Anthony	IT Project Manager
Telecommunications	Geof Axon	Telecommunications planning and engineering manager
Network	Paul Driver	Manager Quality of Supply
	David Gordon	Metering Asset Manager
	Steve Wachtel	Asset Manager
	Jehad Ali	Responsible Person
	Stephen Jolly	Manager Customer Solutions

B METER REPLACEMENT FORECASTS

Annual meter installation rates have been estimated for the following:

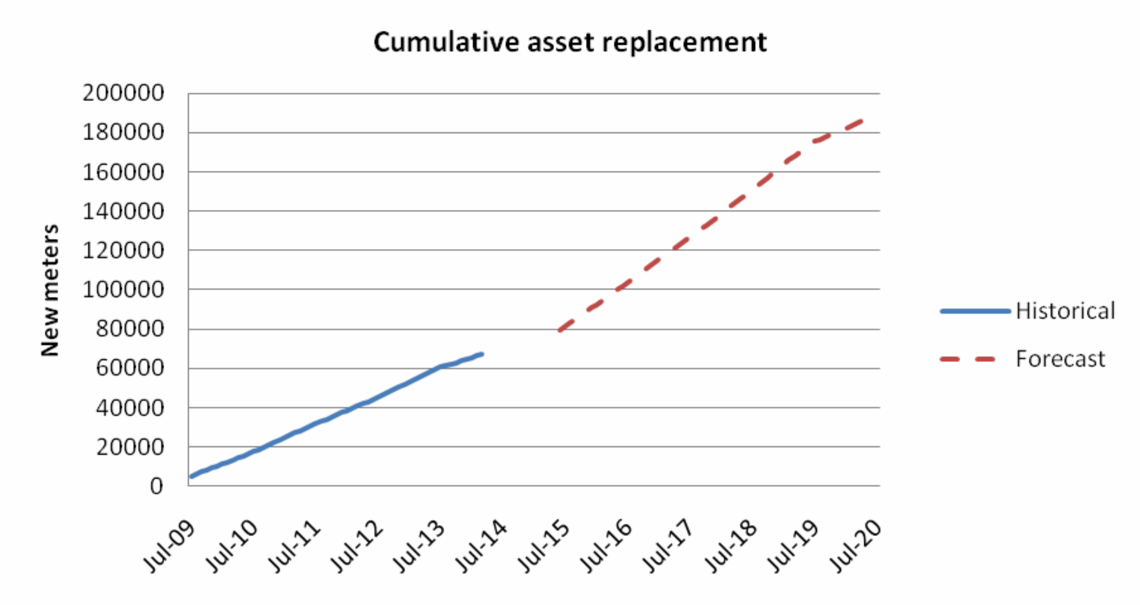
- scheduled asset replacement (asset management)
- new customer connections
- adds and alterations
- new solar connections.

These forecasts are described briefly in the sections that follow.

B.1 Meter asset replacement

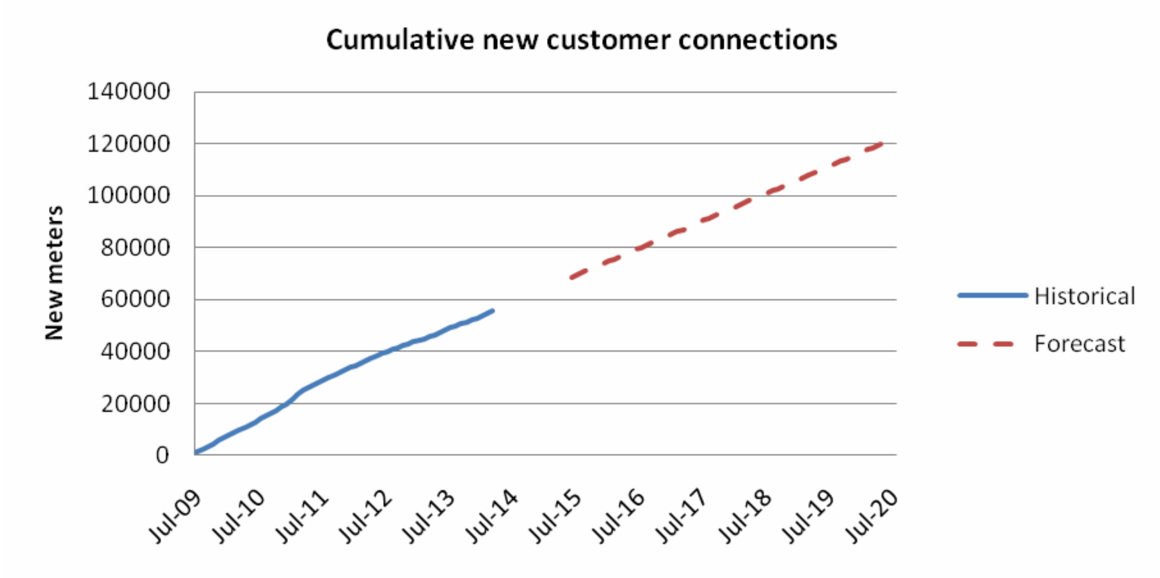
The *Asset Management Plan 3.4.01 Metering 2014 to 2025* [31] identifies specific sub-classes of meters that are defective, no longer compliant to accuracy standards, or otherwise require replacement in the next regulatory period. From the perspective of this business case, it is assumed that all direct connected type 5 and 6 meters that require replacement will be replaced with the new standard smart-ready meter.

The chart below summarises forecast meter replacements vs. historical replacement rates for direct-connected type 5 and type 6 meters; refer to the asset management plan for full details.



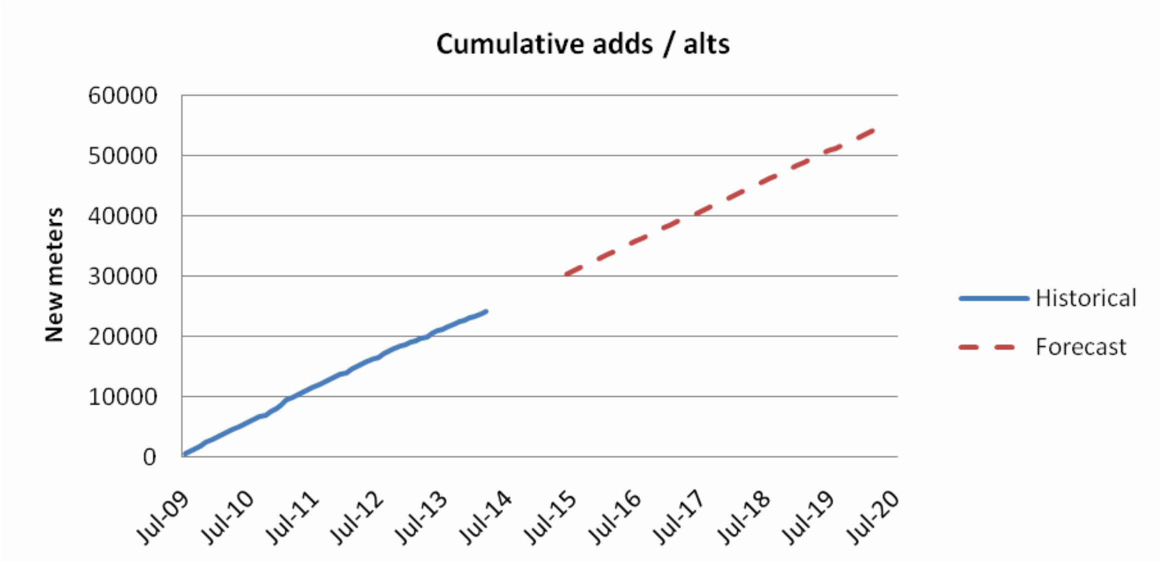
B.2 New customer connections

New customer connections are forecast at 10,500 per annum on average through the 2015-20 period on the basis of demographic data and forecasts prepared by BIS Shrapnel for Customer Solutions [32]. The chart below shows forecast new customer connections against historical trends.



B.3 Additions and alterations

The number of additions and alterations (not including new solar PV installations) is projected at 5,000 per annum on average through 2015-20 based on historical averages, as shown in the chart below. Note that it is estimated that only 1,500 per annum are alterations that require a meter replacement.



B.4 New solar installations

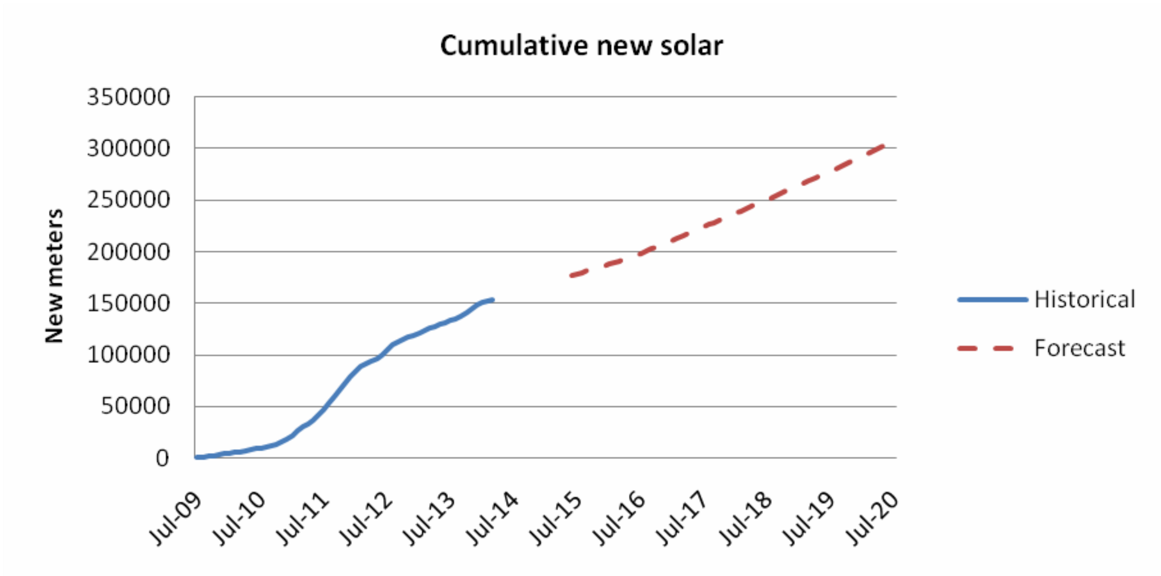
SA Power Networks engaged industry consultant Energeia to model the future uptake of Distributed Energy Resources (DER) in South Australia, taking into account a range of economic factors including projected technology price paths and, in particular, the impact of introducing more cost-reflective network tariffs on customer investment choices.

Energeia's forecasts indicate that solar PV penetration will continue to grow strongly during the next regulatory period. Full details may be found in Energeia's report [9].

For the purpose of this business case we have used Energiea's forecasts as follows:

- We have assumed that every new solar PV (or other DER) installation will require a meter replacement.
- As Energeia's forecasts are by calendar year, we have averaged across two successive years to derive forecasts for each financial year (July to June).
- As Energeia examined a number of different network tariff scenarios, we have used the forecast from their 'Business as Usual (IBT)' model prior to 2017, and their 'maximum demand tariff' model in subsequent years, to reflect our plan to introduce a cost-reflective tariff from mid 2017.

These forecasts are compared with historical installation rates for solar PV in South Australia in the chart below.



C COST OF MONTHLY METER READING

Customers transitioning to the new tariff will also require monthly meter reads. We are proposing to transition all customers to manual monthly meter reading from mid 2017, to coincide with mandatory assignment of customers undertaking additions and alterations to the new tariff. The method used to estimate the impact on manual meter reading costs is outlined below.

Our base assumptions for meter read costs are as follows:

Item	Cost ($)	Source / notes
Type 6 meter reading, per read	1.11	Based on 2012/13 contractor per-meter read charges, scaled to a per-customer cost, average based on 80% metro / 20% country
Type 6 meter reading, quarterly, p.a.	4.44	4 x per read charge
Type 5 meter reading, per read (high volume)	1.332	For high volume type 5 (i.e. new tariff customers) allow 20% uplift on type 6 read cost based on experience with type 5 meters to date; average on-site time for probe read is ~20% greater than manual handheld data entry
Special reads $ per read	7.37	Based on 2012/13 actuals, average 80% metro / 20% country. For special reads, type 5 cost is assumed to be the same as type 6.

Under our proposed tariff introduction schedule, the number of customers that have a new capacity tariff and require monthly meter reading will be:

- Limited to ~2,000 in 2015-16 and 2016-17, with the tariff introduced for pilot customers and selected customer groups only
- An average of ~55,000 per annum from July 2017 when we intend to launch the tariff more broadly and make it mandatory for all new and replacement customers.

We have considered two options for introducing monthly meter reading to support the new tariffs:

- Option 1 – transition all customers to monthly reads from July 2017 (our proposed approach)
- Option 2 – transition customers to monthly reads progressively as they transition to the new tariff

A key factor in comparing these options is that manual meter reading is highly cost-efficient today because a meter reader will visit every premises on the street when following a read route, so the non-productive travel time between reads is minimised. One-off or out-of-sequence reads are much more expensive than scheduled reads as a result.

C.1 Option 1

Our proposed approach is:

- In 2015-16 and 2016-17, the initial customers that take up the new tariff will be removed from quarterly read routes and placed on new monthly reading arrangements. As these customers are very few in number and expected to be geographically dispersed, we do not expect any of the normal economies of scale to apply when manually reading these meters. We assume that the average per-read cost for these customers will be equivalent to the one off 'special read' cost today, and hence the annual read cost will be 12 x the special read cost.

- From July 2017 we will transition all customers to monthly meter reads. This effectively results in a 3 x increase in meter reading effort. Under this approach we expect no net loss or gain in efficiency compared to quarterly reading, as essentially the same read routes are retained and run more frequently. Hence we assume that the annual cost of monthly reading is 3 x the annual cost of quarterly reading.

C.2 Option 2

Under this option:

- Meter reading costs for the ~2,000 customers taking up the tariff prior to July 2017 are assumed to be the same as in option 1.
- From July 2017 we would transition only those customers moving to the new tariff to monthly meter reading. Other customers would remain on quarterly meter reading until such time as they changed tariff.

To estimate total monthly meter reading costs under this option we have assumed:

- Per-customer monthly read cost is initially 12 x special read cost, as we assume that at low volumes there is no opportunity to organise customers into efficient monthly read routes
- As more customers transition to monthly reads it becomes possible to create more efficient monthly read routes, and the average per-customer read cost for monthly reads decreases progressively with customer volume from (12 x special read cost) towards (12 x regular read cost).

We have modelled the decrease in per-read cost with growing customer volume under our proposed tariff rollout schedule as shown in the figure below (incremental cost compared to current quarterly read cost is shown, $2014).

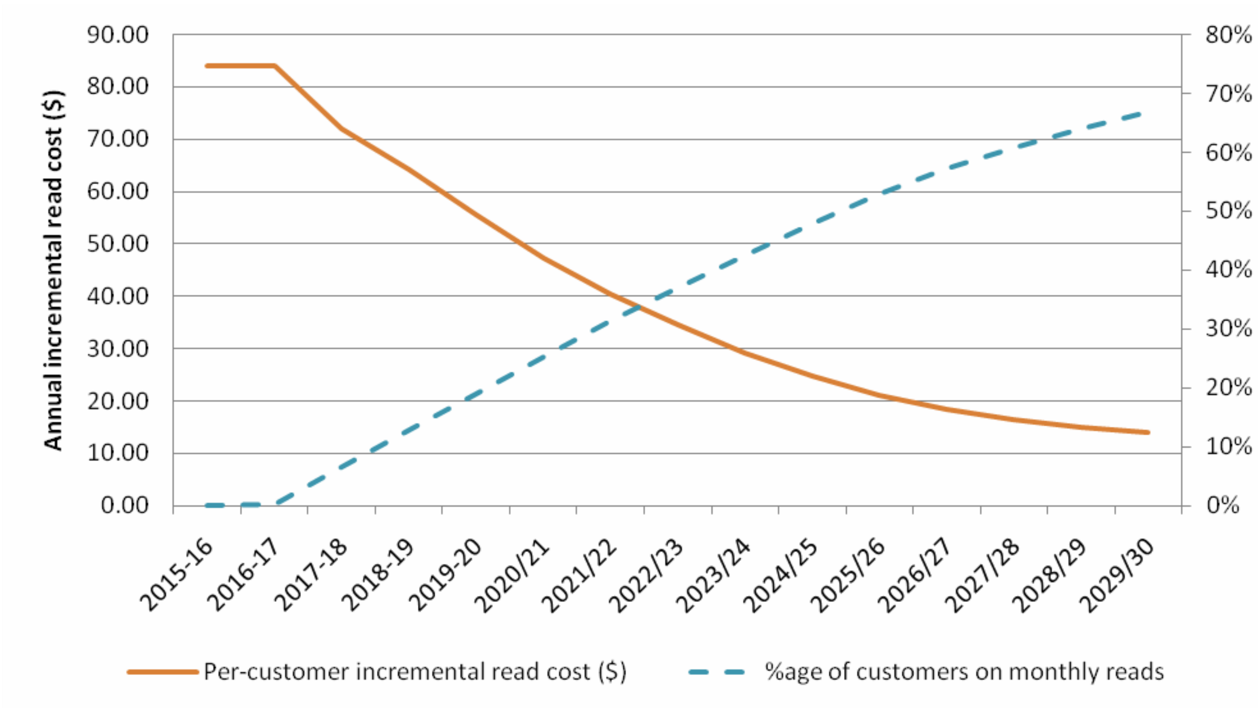


Figure 18 - Monthly read cost path

C.3 Comparison of options

The figure below compares estimated total incremental annual meter reading cost (vs. a BAU scenario in which all customers remain on quarterly reading) of option 1 and option 2.

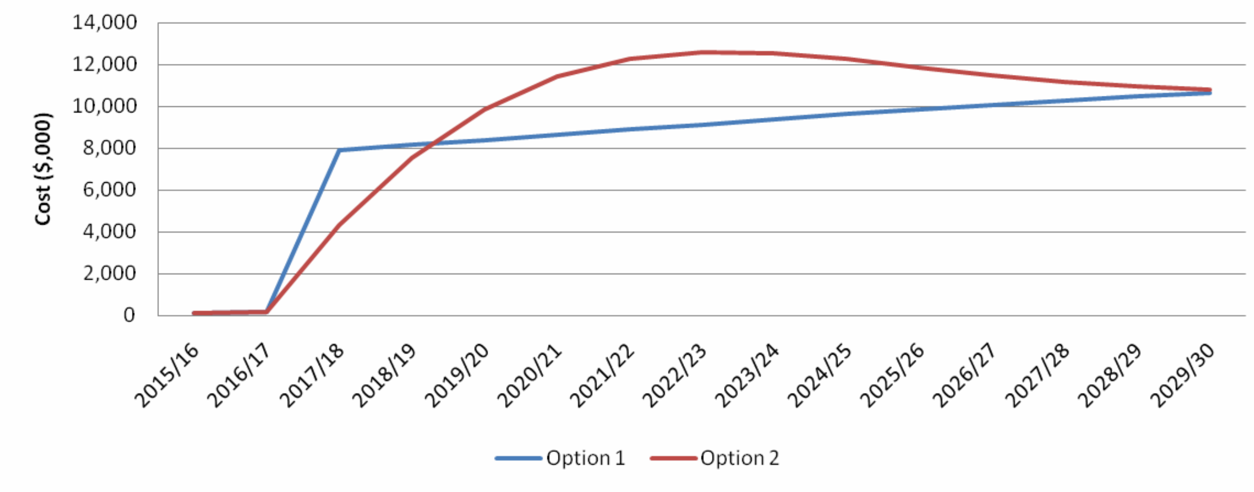


Figure 19 - comparison of meter reading costs

Figures shown for option 2 are indicative based on the following assumptions:

- Monthly read price for new tariff customers reduces with volume as shown in Figure 18 above.
- Quarterly read price for legacy tariff customers increases similarly over time due to reduced efficiency as customers that transition to monthly reading leave 'holes' in quarterly read routes, doubling by 2030.

Option 1, in which all customers transition to monthly meter reading from July 2017, has higher total cost initially. From 2020, the total cost under option 2, in which new tariff customers are read monthly and legacy tariff customers remain on quarterly reads, exceeds that of reading all customers monthly, as economies of scale are reduced in the mixed approach.

When back office as well as meter reading costs under options 1 and 2 are considered, the modelling indicates that option 2 would have a total cost (15 year NPV) of 2% - 5% lower than option 1[15]. However, option 1 remains preferred because:

- Compared to option 2, option 1 has the significant additional benefit that **all customers receive the benefits of monthly meter reading from July 2017**, not just customers that transition to a new tariff. Monthly reading is an enabler for monthly billing based on actual (not estimated) reads. Market research indicates that consumers prefer monthly billing, and consumer advocates such as SACOSS strongly favour monthly billing as a tool to reduce 'bill shock' for vulnerable customers.
- Option 1 also benefits from logistical simplicity, as it avoids the ongoing churn of customers from quarterly to monthly read routes.

Finally, note that although we have projected manual monthly meter reading costs over 15 years in order to compare options, we anticipate a significant uptake of remotely-read meters in South Australia from the latter part of the 2015-20 period onwards. For a remotely-read meter the cost of monthly meter reading is no more than the cost of quarterly meter reading,

[15] Depending on the %age of backoffice costs that are fixed – sensitivities modelled were 10% - 30% fixed cost.

and so the long-term cost impact of a transition to monthly meter reading as standard for all customers in 2017 is expected to be lower than the cost projections used for the comparison.

D IT COST ESTIMATES

Cost estimates for the IT elements of this business case were developed as follows:

- SA Power Networks engaged with Victorian DBs in late 2013 in a series of meetings to discuss lessons learned from the Victorian AMI program, culminating in an all-day workshop in Melbourne on 23rd October 2013.
- An initial set of work items with high-level CAPEX and OPEX estimates was developed 'top down' through these initial discussions.
- SA Power Networks engaged Deloitte in April 2014 to lead a process to refine these initial high level estimates into final estimates for the relevant IT costing papers. This involved further consultation with key subject matter experts within SA Power Networks, further meetings with Victorian DBs, and the construction of more detailed 'bottom up' cost models. Deloitte also took into account synergies with other relevant IT projects proposed for the 2015-20 reset period. This work commenced in May 2014 and completed in mid July 2014.
- In the same timeframe Deloitte were also engaged to assist with the development of the *Customer and Retailer Engagement Strategy*. This project included a workshop with key internal stakeholders to explore the technical and business process change aspects of supporting the new tariff with existing meter reading and billing systems, in particular with an 'enhanced type 6' meter. The outputs of this workshop were inputs to the IT cost estimation process.

The detailed cost estimates, and all associated assumptions, are included in the relevant IT costing paper documentation [32].

E NETWORK BENEFITS OF SMART METERS

E.1 Available benefits

This appendix examines the opportunity to derive qualitative and quantitative operational benefits from the following functions of smart meters, specifically in the context of a ‘sparse but targeted’ deployment to only 7% of customer premises:

- Load control
- Last gasp / service restoration alerts
- Remote disconnect / reconnect
- Remote ping

These are the functions that we intend to enable when we install communications in our own meters, but we also expect to be able to access them for third-party meters in future through the development of interfaces to the AEMC’s proposed common market gateway, assuming SCER’s proposed rule change for full metering contestability comes into effect mid-way through the 2015-20 period.

E.1.1 Load control

Today, there are ~300,000 customers in South Australia with a controlled-load hot water service, and for 95% of these the controlled load circuit is switched on overnight using a local time clock, either integrated in the meter or external to the meter. When a meter is enabled with telecommunications, the load control function can be operated remotely, and this has some significant benefits over the local time-switched approach [1]:

- It enables regular load switching times to be varied as and when required to optimise the benefits according to local conditions or changing circumstances, something that is not practical today as it requires a visit to every customer premises to reconfigure the meter. As an example of the potential benefit, we have been made aware that the current synchronised switching of hot water load at the beginning of the overnight off-peak period is causing a spike in demand, and a corresponding spike in the NEM spot price for energy. If we had this capability today this issue could be resolved quickly and at very low cost simply by remote reconfiguration of meters to vary startup times over a wider time period.
- It creates the opportunity to offer customers more choice in controlled load products; as well as a simple overnight ‘off-peak’ controlled load circuit, customers can be offered a controlled load tariff similar to tariffs offered in Queensland, in which the circuit is generally on during the day, but the customer pays a reduced price on the understanding that it may be turned off during peak times.
- It creates new opportunities in future, in particular when there is a critical mass of customers with load under remote control. As an example, an opportunity of specific interest to SA Power Networks is the possibility of using hot water load as a sink to absorb excess solar generation in areas where high solar penetration could otherwise cause local over-voltage problems on mild, sunny days.

Whenever a telecommunications module is installed for network monitoring, and there is an existing hot water load control service at the premises, we will enable remote load control. At the proposed deployment rate of 10,000 modules per annum, this would see ~3,500 premises p.a. transitioned from time-switch to remote load control.

During the period, we may also consider targeted replacement of meters in addition to these specifically to implement remote load control, e.g.:

- in constrained areas in order to defer network augmentation, where a direct load control program passes the RIT-D test
- in order to replace legacy SWD remote load control for the small number of customers who are still on this system, if this proved to be more cost-effective than maintaining the SWD equipment due to the obsolescence of this equipment

Opportunities such as these will be considered on a case-by-case basis in the latter part of the 2015-20 period should they arise, but they are more likely to occur in the following regulatory period, when there is a greater penetration of meters (including third-party smart meters). No such projects have been included in this business case.

E.1.2 Last gasp / service restoration

Meters that are enabled with remote communications provide 'last gasp' notifications when power is lost and automated supply restoration notification when supply is restored. Through appropriate integration with OMS, these messages can be used to determine the location of network faults or storm damage and confirm when repair efforts have been successful.

These last-gasp messages and service restoration messages are of the most value when the fault or network damage is localised to one or more suburbs or streets, and in particular when the problem is with the LV network. These are typical characteristics of outages due to storm events[16]. In circumstances such as these, last-gasp messages can expedite fault location and repair, and can also enable secondary damage downstream of the primary fault to be identified while the restoration crew is still in the area, by identifying that not all customers have come back on supply after repair work is complete. These benefits can result in improved customer service, improved SAIDI and reduced GSL payments.

To obtain outage-detection benefits requires a reasonable critical mass of meters capable of last gasps across the network, noting that in general not all meters will successfully raise an alarm during a power outage[17]. It is not, however, necessary to have a smart meter in every home in order to achieve these benefits; 2-3 alarms is generally sufficient to locate the fault to a single LV transformer or feeder.

Our proposed approach of progressively deploying communications modules at up to three premises on each LV feeder for power quality monitoring is also well suited to establishing an effective outage detection capability across these areas of the LV network at least cost.

E.1.3 Remote disconnect / reconnect

The capability to remotely disconnect and reconnect supply delivers a material per-meter saving in the avoided cost of attending customer premises. Unlike some other benefits, the saving can reasonably be achieved on a per-meter basis without relying on a significant critical mass of meters that provide the function.

The savings associated with remote disconnection and reconnection represent a significant portion of the total financial benefits generally attributed to smart meters (the Productivity Commission's 2012 review of the Victorian smart meter rollout attributed 40% of available

[16] Last gasps add less value for major failures to single pieces of infrastructure such as substations, which are readily detected through SCADA and result in many customer calls, or for single-customer outages where investigation would be required in any event to confirm the reason for the loss of supply.

[17] This is because of the limited time the communication module's in-built capacitor can maintain power once the main supply has been lost.

benefits to this function [19]). We will enable this capability whenever a module is installed in order to access this benefit.

E.1.4 Remote ping

When a meter is enabled with telecommunications it is possible to remotely interrogate the meter in near real time to test to see whether there is supply to the premises, and to check voltage levels and perform other basic diagnostics when a customer calls to report a fault. In 2013, SA Power Networks' crews attended 9,830 jobs at customer premises for issues that turned out to be customer-side problems, and hence there is the potential for substantial savings in the long term. This capability can also be used to pro-actively sample customer premises in a particular area for targeted investigation into suspected power quality problems, local network constrains, etc.

E.2 Quantifying benefits

SA Power Networks engaged Deloitte in April 2014 to estimate the value of these benefits, using the same methodology used in their 2011 review of the future benefits of the Victorian smart meter rollout, but adapted to take into account:

- The fact that we are only proposing to install communications to a small percentage of meters in specific target areas of the network, as opposed to the full rollout in Victoria
- Available opportunities for efficiency gains based on SA Power Networks current operating practice and operating costs
- A review of actual benefits that are being achieved in Victoria now that the rollout is essentially complete and the benefits realisation phase has begun.

Deloitte's original 2011 study examined 21 specific operational benefits expected from smart meters in Victoria, and estimated the total saving attributed to each over a 20-year timeframe, expressed as a present value in 2008 dollars [21]. Undertaken part-way through the Victorian rollout, this study revised the value of a number of these benefits downward relative to earlier studies.

For this business case, Deloitte, in consultation with SA Power Networks, mapped the original 21 benefits from the 2011 study to the five functions we propose to enable, as shown in the table below:

Operational benefit	Deloitte 2011 value (millions, NPV)	Deloitte 2011 proportion	Application to SA	Function / reason for excluding
Remote disconnect/reconnect savings	358	40.09%	YES	Remote disconnect / reconnect
Reduction in manual meter read costs	154	17.25%	YES	Remote reading
Reduction in special read costs (not inc associated with disconnect)		0.00%		Zero benefit in 2011 study
Outage detection / service restoration - SAIDI benefits	66	7.39%	YES	Last gasp
Time switch clock error avoided energy cost	26	2.91%		Not applicable in SA context
Non technical losses	27	3.02%		Benefit due to early meter replacement, not applicable to new & replacement approach
Avoided cost of transformer failure due to better monitoring	20	2.25%		Benefit sought through transformer monitoring programs
Emergency demand limiting during network stress or supply shortage	82	9.18%		Potential future benefit – not yet proven
Avoided cost of investigation of customer complaints about power quality	39	4.37%	YES	Power quality / other monitoring

Operational benefit	Deloitte 2011 value (millions, NPV)	Deloitte 2011 proportion	Application to SA	Function / reason for excluding
Avoided cost of installing import/export metering	35	3.92%		Benefit arises from 100% rollout, not applicable to new & replacement approach
Avoided cost of investigation of customer loss of supply found to be other cause	15	1.68%	YES	Remote ping
Reduction in calls to fault and emergency lines	14	1.57%		Expected benefit not yet achieved in practice in Victoria
Customer benefit of easier retailer switching	8	0.90%		Insufficient evidence to quantify benefit at low meter penetration
Reduced testing of meters	7	0.78%		Benefit arises from consolidation of meter types in 100% rollout. Insufficient data to quantify benefit in new and replacement approach
Reduced cost of network load studies for network planning	5	0.56%		Expected benefit in FTE reduction yet to be proven in Victoria
Avoided cost of service fuse failure and HV/LV transformer fuse operation	10	1.12%		Potential constrained transformers are targeted with dedicated transformer monitoring
Reduction in estimated/high bill enquiries	5	0.56%		Insufficient data to quantify in SA context
Avoided cost of supply capacity circuit breaker	4	0.45%		Potential constrained transformers are targeted with dedicated transformer monitoring
Avoided cost of end-of-line monitoring	4	0.45%		Targeted EOL monitoring is complementary in SA context
Avoided cost of feeder automation comms equipment (only if same comms used)	3	0.34%		Not assuming dedicated telecommunications infrastructure
Reduction in bad debt administration cost	2	0.22%		Insufficient data from Victoria to establish that benefit is realised

E.2.1 Value of network functions

The following extracts from Deloitte's report for SA Power Networks [34] summarise the methodology used to estimate the value of the four network operational functions we propose to enable:

Power quality monitoring

Where a smart meter has been installed, SA Power Networks expects that there will be a reduced need to install equipment to monitor power quality in response to a complaint, however the proportion of sites where this cost will be avoided is not currently known. In the absence of data to support an estimate, we consider it is reasonably conservative to expect that 50% of complaints that occur where a smart meter has been installed could avoid the need for power quality monitoring equipment to be installed.

We have estimated this benefit based on the following assumptions:

- *Forecast annual number of customer complaints about power quality, provided by SA Power Networks*
- *Average cost of installing monitoring equipment to investigate a complaint about power quality in 2013– $2,400 per complaint, based on advice from SA Power Networks.*
- *Adjustment to account for classes of complaint which cannot be resolved without installing monitoring equipment (50% conservative estimate)*

- *Adjustment to account for smart meter coverage (reaches a maximum of 7% in 2020)*
- *Discount for benefits in first two years to account for likely availability and effectiveness of new systems (applied to all benefit categories). Assume no benefit realisation in Year 1 and 50% benefit realisation in Year 2.*

Outage detection / service restoration – SAIDI benefits

Given the proposed structure of SA Power Networks' smart meter rollout, with a maximum penetration of 7% of smart meter coverage, we expect that benefits associated with outage detection will be significantly limited when compared to a mass rollout scenario such as Victoria. Assuming outages are evenly distributed across the network, with smart metering penetration at 7% we estimate that 7% of the benefits assumed for Victoria in the Deloitte 2011 CBA might be realised by SA Power Networks. This is a conservative estimate, however in the absence of any trials to identify that detection of outages would improve by more than the meter penetration, we consider this is a reasonable estimate.

We have estimated benefits for SA Power Networks based on the following assumptions:

- *Average SAIDI for SA Power Networks (143 minutes per customer per annum)*
- *Average saving of 4% of total minutes off supply (based on the Deloitte 2011 CBA – average of 5 distributors)*
- *Weighted average residential and C&I customer load of 0.7 kW*
- *VCR for South Australia of $48.7/kWh ($2014), based on AEMO data*
- *Adjustment to account for smart meter coverage, because with a smaller number of meters in the field, there is a lower likelihood of detection of outages*
- *Discount for benefits in first two years to account for likely availability and effectiveness of new systems (applied to all benefit categories). Assume no benefit realisation in Year 1 and 50% benefit realisation in Year 2.*

Remote disconnect / reconnect

There is some uncertainty as to whether South Australian electricity retailers would agree to implement remote metering services where only 7% of customers could access them. However, given most retailers operate both in South Australia and Victoria, the changes made to processes and systems are likely to be transferrable to South Australia. In fact, we consider it is reasonable to expect that these benefits would be achieved sooner for SA Power Networks' customers of the retailers currently offering these services in Victoria, given the arrangements for implementing these tariffs in South Australia are likely to be similar to those established in Victoria.

We have estimated benefits for SA Power Networks based on the following assumptions:

- *Current cost of special read, connection and disconnection services ($42 per transaction)*
- *Average number of customer move in/outs per annum (16%)*
- *South Australian Market share of the two major retailers currently providing services in Victoria (72%)*
- *Adjustment to account for smart meter coverage*

- *Discount for benefits in first two years to account for likely availability and effectiveness of new systems (applied to all benefit categories). Assume no benefit realisation in Year 1 and 50% benefit realisation in Year 2.*

Remote ping

In our view, it is reasonable to expect that some truck visits could be avoided due to smart metering information. However, any savings need to be adjusted to account for the fact that only 7% of meter coverage is being proposed by SA Power Networks.

We have estimated benefits for SA Power Networks based on the following assumptions:

- *Current annual rate of truck visits requested by a customer (10,000)*
- *Average cost of a truck visit ($122)*
- *Victorian experience in reducing overall truck visits requested by a customer (25%)*
- *Adjustment to account for smart meter coverage.*
- *Discount for benefits in first two years to account for likely availability and effectiveness of new systems (applied to all benefit categories). Assume no benefit realisation in Year 1 and 50% benefit realisation in Year 2.*

E.2.2 Remote meter reading

Under the current rules, networks cannot generally recover the cost of remotely-read meters as part of their regulated metering charge, other than in cases where manual meter reading is not practical. In general, a remotely read meter is a Type 4 meter, which is not a regulated service.

Remote meter reading is not a requirement for our capacity tariff; our tariff requires monthly reads, but this in itself is not sufficient to justify the cost of enabling telecommunications to all meters.

As we enable communications in a subset of our new meters to enable other network benefits, we may take advantage of the opportunity to read some of these meters remotely to the extent that the rules allow, where there are customer or operational benefits in so-doing. We expect this would include remote reading of type 5 meters in circumstances where operational difficulties make manual reading impractical.

We have not assumed any material quantified benefits from such remote meter reading as part of this business case[18], noting that we are targeting only a small proportion of customer premises, and these are in predominantly urban areas where remotely reading a small subset of customers would not yield material savings in manual meter reading costs.

E.2.3 Benefits due to demand reduction

While one of the key benefits of moving to a ‘smart ready’ meter as standard is that it will create future opportunities to add communications specifically for direct load control to address network constraints, we are not proposing to enable meters with telecommunications for DLC in this business case; such opportunities may be pursued in future where a positive benefits case is established, subject to a RIT-D test.

[18] Deloitte examined the potential benefit in terms of the avoided cost of monthly meter reading for those customers on new tariffs whose premises were selected for installation of a communications module for network management. This analysis was in the context of reducing the high monthly read costs for these customers under a progressive approach to transitioning to monthly meter reading. This benefit is not material under our proposed approach, which is to transition all customers to monthly meter reads, and has been excluded.

Similarly, although we will take the opportunity when installing telecommunications to transition those customers with existing time-clock hot water load control to remote switching, we do not expect this to create opportunities to reduce peak demand in the next regulatory period; rather it may create new opportunities to manage voltage variation in areas of high PV penetration by transferring off-peak load to times of excess solar generation.

For the above reasons, we have not assumed any demand reduction benefits from our proposed deployment of communications modules in this business case for the 2015-20 period. The potential for demand reduction programs in the 2020-25 period will depend to an extent on the penetration of third-party smart meters.

E.3 Benefits realisation

We have assumed that available benefits are realised over time, as follows:

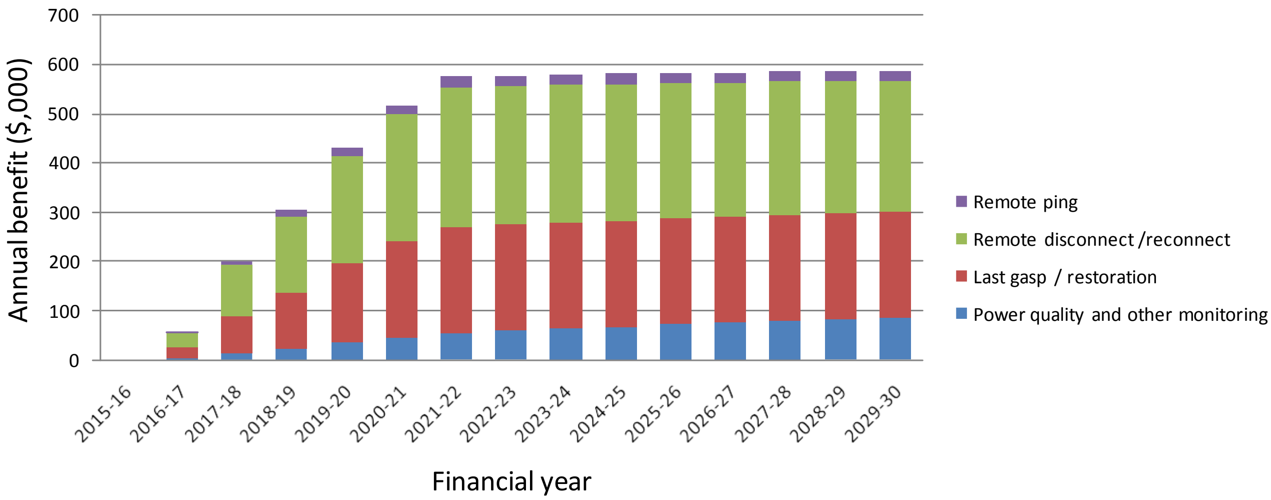
- The available value of each individual benefit ramps up as the number of telecommunications meters increases to 2021, to the maximum available annual benefits as described above.
- Benefits in the first five years are discounted by a factor that represents our overall capability to realise benefits. We have assumed no benefits in the first year, to reflect the fact that the backoffice systems and business processes required to realise operational benefits from our meters will be under development during this time. From 2016-17 onwards we assume that our overall capability to realise available benefits ramps up, reaching 100% in 2021-22.

The overall benefits realisation schedule to 2024 is shown in Table 22 below.

	Benefits realisation schedule - total benefit $,000									
Operational benefit	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25
Overall capability to derive benefits	0%	60%	70%	80%	90%	90%	100%	100%	100%	100%
Power quality and other monitoring	0	3	13	22	35	46	55	59	64	68
Last gasp / restoration	0	22	76	114	161	194	215	215	215	215
Remote disconnect /reconnect	0	30	104	156	218	259	285	283	280	278
Remote ping	0	2	7	11	15	18	20	20	20	20
Total operational benefit ($,000)	**0**	**57**	**200**	**304**	**429**	**517**	**575**	**577**	**579**	**581**

Table 22 – Benefits realisation schedule (to 2024 only shown)

The figure below shows the escalation of annual benefit over time under the above benefits realisation schedule.


700
600
500
400
300
200
100
0
Annual benefit ($,000)
2015-16
2016-17
2017-18
2018-19
2019-20
2020-21
2021-22
2022-23
2023-24
2024-25
2025-26
2026-27
2027-28
2028-29
2029-30
Financial year
Remote ping
Remote disconnect /reconnect
Last gasp / restoration
Power quality and other monitoring

F TYPE 5 VS. TYPE 6 METERING FOR THE CAPACITY TARIFF

F.1 Current rules

Under the rules today, SA Power Networks has the monopoly right to install two types of meter:

- Type 6 – a manually-read accumulation meter. This is our standard regulated meter for residential customers. A modern electronic type 6 meter has a display that the meter reader can use to cycle through the register data stored in the meter, and the meter reader manually enters the values of the relevant accumulated energy registers to a handheld device
- Type 5 – a manually-read interval meter. Today, customers of >100A (typically small business) must have a type 5 meter, and customers of <100A (e.g. residential customers) can opt to have a type 5 meter for an additional fee. A type 5 meter is read using an optical probe that downloads the half-hourly interval data (and potentially other data) stored in the meter directly to the meter reader's handheld device. Type 5 metering services are currently Negotiated Distribution Services (NDS). However, from the start of the 2015-20 regulatory period type 5 metering services will be re-classified as Alternative Control Services (ACS) and we will include either type 5 or type 6 meter reads as part of our standard regulated metering service.

F.2 Proposed new standard meter

In order to calculate peak demand for the month, we require a meter that is capable of recording the highest half-hourly consumption reached during the period. We have considered two options:

1. Install a type 5 meter and calculate peak demand each month based on an analysis of the interval data for the period.
2. Install a more advanced type 6 meter that is capable of measuring and recording the peak half-hourly demand reached during the month in a register, and allow customers to opt in to a type 5 meter if they choose to do so.

Option 1 is preferred as it is simpler and there are additional benefits in having interval data for all customers. However, for this business case we have assumed that we may also have to support option 2 because:

- State Government policy may mandate that customers must be able to 'opt out' of an interval meter to a type 6 meter [6].
- Current rules effectively allow networks to enable communications on type 6 meters, but not type 5 meters, and we want to retain the option to enable communications on meters for network purposes.

F.3 SA Government's proposed New and Replacement policy

In its discussion paper released in January 2015 [5], the SA Government proposed a minimum standard for all new and replacement meters to come into effect at the time of the metering contestability rule change whereby all new meters would have to be 'smart ready' interval meters unless the customer explicitly opts out, in which case a basic accumulation meter could still be installed. We have indicated our support for this proposal, on the proviso that existing impediments in the rules to adding communications to type 5 meters for network purposes are removed, and the basic 'opt-out' type 6 meter is still capable of enabling our capacity tariff [24].

Should this policy be adopted, we would need to be able to support the capacity tariff for customers that chose to opt-out to a type 6 meter, otherwise customers could avoid the tariff by exercising their right to opt out of a type 5 meter and the outcomes that we are seeking from the new tariff will be at risk.

F.4 Benefits of type 5 metering

Although interval metering is not strictly required to enable standard capacity-based network tariff, it does present a number of benefits:

- We believe customers are likely to want access to historical interval data in order to understand and respond to the price signals in our new tariff.
- Interval data is clearly an enabler for customers to better understand their consumption patterns more generally in order to more actively manage their energy use and participate in the demand side of the market. Providing customers with access to better information through smarter metering is a clear policy goal of the AEMC, SCER and the state Government.
- A capacity tariff is considerable simpler to implement with a type 5 meter. Both SA Power Networks and retailers already have systems in place to calculate similar demand tariffs from interval data, whereas there is considerable technical effort in implementing the necessary system changes to support the tariff with a type 6 meter using capacity registers (both for ourselves and retailers).

F.5 Technical assumptions: support for type 6 metering with capacity registers

There are a number of changes required to meter firmware, backoffice systems and business processes to enable the capacity tariff with a type 6 meter, some of which will require further work to fully define. The effort estimates in this business case are based on the assumptions summarised below, elicited from a series of technical workshops with key stakeholders facilitated by Deloitte.

F.5.1 Meter functionality assumptions

- Record maximum kW demand and store it in a register
- Max demand to be defined as highest 30 minute interval reading between the hours of 1600 and 2100 for the calendar month, expressed as a kW figure (i.e. measured 30-minute kWh consumption * 2)
- For a three-phase customer there is a single maximum demand figure, being the sum of the interval readings for all three phases.
- Whenever a new maximum for the month is reached, meter to store, in separate registers, the following three quantities:
    - The new highest kW value
    - The time of the interval, expressed as numerical value, e.g. 1930 for the 30-minute interval commencing at 7:30pm
    - The date of the interval, expressed as a unique numerical value such that each day's value is greater than the previous, e.g. 20140616 for 16th June 2014
- The demand component of the tariff is based on the maximum demand recorded for the last whole calendar month. There are two sets of registers for maximum demand, date and time. The first set records current month maximum demand, date and time (these may appear on the Alt 1 display to reduce reader error). The second set are those to be read (displayed in the normal display setting) which show the previous

month's maximum demand, date and time. At the conclusion of the final interval on the last day of the calendar month the values for maximum demand, date and time registers are transferred to the second set of reading registers and then the first set is reset to zero.

- Meter reader would need a means to manually reset the maximum demand and date/time stamp registers mid-way through the month, for a move-out/move-in scenario.
- Meter would also record 30-minute interval data internally

F.5.2 Meter reading assumptions

- Meter reads will be scheduled monthly for customers on the capacity tariff
- During a scheduled meter read:
  - Meter reader will enter peak demand and date/time stamp register values to the relevant fields on the handheld device. This will be the maximum peak demand reached in the previous calendar month – i.e. if the meter reading takes place on the 15th of April, it will be the maximum demand that occurred between 1st March and 31st March.
  - Meter reader will enter the values of the accumulated energy register(s) as normal, i.e. the total energy consumed up to the meter reading date (e.g. 15th April)
- For a special read for customer move-out/move-in, disconnect/reconnect:
  - As above but meter reader will need to read both last month and current month demand registers, and reset the current month demand registers after taking the read
- For a missed read where the capacity registers have been overwritten with the values for a subsequent calendar month or months, the meter would be probed to download its stored interval data, and there would need to be an internal process to calculate the actual maximum demand in the months that were missed. In this case the interval data would not flow to market (as the meter would still be a Type 6). (The reading process for this would be a special process and would require handhelds that were not attached to production reading systems.)
- We assume that estimated values would be substituted when reads have been missed, and these would be determined using a similar hierarchy of rules to current estimation processes (e.g. value for same month last year if available, or last month, or a default value, etc). When the actual reads are collected the billing process will follow the established BAU process for when replacement readings are obtained. There is no impact on NEM Settlements as the NEM is concerned with energy readings only.

F.5.3 IT backoffice systems

- Modification will be required to:
  - Multi-Vendor Reading System (MVRS)
  - PDE (handheld device)
  - IEE (Meter Data Management system)
  - Customer Information System Open – Vision (CIS/OV)
  - Market Transaction System (MTS)

- Gateway and system integration

- Resource estimate is calculated based on the component, component type (e.g. new screens, changed screens, new programs, changed programs etc.), and complexity (e.g. simple, medium, complex and very complex).
- Canonical entities are used for system integration, assuming it involves changing existing message definitions and not re-developing, under SOA integration principles.
- Total number of additional bytes per read is assumed to be 24 bytes
- Data increase as a result of the additional registers is assumed to be 4.32 MB per annum
- Assumed meter read record data = 2000 bytes
- Meter read data growth is assumed to be 1.2%
- Total data volume growth per annum is assumed to be 17.56%
- Data storage for IEE and MTS to store the additional three registers would increase by 2GB per annum which is calculated at the rate of $7 per GB
- Additional processing power (CPU) has not been calculated. Information received from SA Power Networks indicated that current processing capacity is 3 times that currently implemented within CP/PAL and was therefore sufficient to handle current growth projections