

Department of
Treasury and Finance
Advanced metering
infrastructure cost benefit
analysis



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Glossary

Term	Meaning
Accumulation meters	Electricity meters that only measure total electrical energy use (kWh, MWh) between meter readings
Advanced Metering Infrastructure (AMI)	Remotely read interval meters (also Smart Meters) and associated equipment that together is capable of (among other things): recording of energy imported or exported from a metering point by half hour trading interval; remote disconnection and reconnection (re-energisation and de-energisation); load control; and remote detection of loss of supply. ¹
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AMI	See “advanced metering infrastructure”
Capex	Capital expenditure
CitiPower	CitiPower Pty
Controlled load	Customer appliances that are connected to a dedicated circuit and are subject to separate metering of energy use – usually hot water heating. The relevant controlled load would only be “ON” at restricted times of day
CPM	Connection Point Management
CPUC	California Public Utilities Commission
Critical peak pricing (CPP)	Under critical peak pricing, electricity prices are increased sharply for a limited duration at times when demand needs to be reduced. We have also referred to Critical Peak Incentives in this report, which involve providing rewards to customers for reducing demand at times of peak energy use
Distributor	Electricity Distribution Network Service Provider: a business that owns the metering infrastructure and manages the distribution of electricity through the ‘poles and wires’ network
Dol	Victorian Department of Infrastructure
DPI	Victorian Department of Primary Industries
DTF	Victorian Department of Treasury and Finance
EMCa	Energy Market Consulting Associates
ESC	Victorian Essential Services Commission
FRC	Full Retail Competition
IEEE	Institute of Electrical and Electronics Engineers
IHD	In Home Display
IMRO	Interval Meter Rollout program

¹ The full functionality of AMI metering is specified in DPI, *Minimum AMI Functionality Specification (Victoria), Release 1.1*, September 2008. Available at: http://new.dpi.vic.gov.au/data/assets/pdf_file/0014/13109/Minimum-AMI-Functionality-Specification-Victoria.pdf

Term	Meaning
Interval meter	Electricity meter capable of recording energy use over short intervals, typically every half hour.
IP	Internet Protocol
JEN	Jemena Electricity Networks
Kbs	Kilobits per second
kW, MW, GW	Kilowatt, megawatt, gigawatt: a measure of the amount of electricity either generated or used at any given instant of time – also referred to as “demand”
kWh, MWh, GWh	Mega watt hours: a measure of the volume of electricity used over a period of time – also referred to as “energy”
Manually Read Interval Meter (MRIM)	Early technology interval meters with limited functionality and which are generally read via a manually inserted probe
Mbs	Megabytes per second
National Metering Identifier (NMI)	A unique identifier of each registered metering point
NMI	See “national metering identifier”
NMS	Network Management System
NPV	Net Present Value
OIC	Order in Council
Opex	Operating expenditure
P2P	Device to device
Powercor	Powercor Australia Limited
Retailer	An electricity retail business that provides billing services to customers and generally manages the customers’ interface with other parts of the electricity industry
RF	Radio frequency
SCE	Southern California Edison
Smart meter	See ‘Advanced metering infrastructure.’
SP AusNet	SP AusNet Pty Limited
SSN	Silver Springs Network – creator of AMI communications technology deployed by four of the Victorian distributors
ToU	Time of Use
UED	United Energy Distribution
VAGO	Victorian Auditor General Office
WiMAX	Worldwide Interoperability for Microwave Access

Executive summary

Introduction

Since 2009, more than 650 000 smart meters have been installed in Victoria as part of the Victorian Government's Advanced Metering Infrastructure (AMI) Program. By the end of 2011, the Victorian electricity distribution businesses will have installed smart meters at almost 50% of small customer sites.

Deloitte has been appointed by the Victorian Department of Treasury and Finance (DTF) to undertake a reassessment of the costs and benefits of the AMI Program. The project also involves identifying ways to enhance the net benefits of AMI to customers.

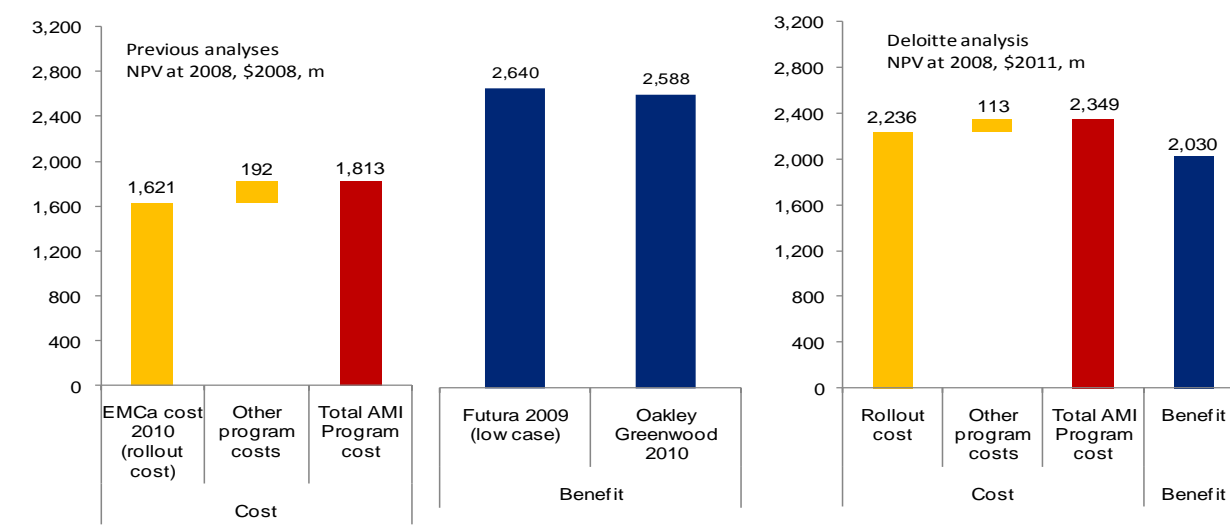
Our review has involved analysis of the costs and benefits stemming from the following three scenarios: (1) total AMI Program over 2008-28; (2) continuing the AMI Program from 2012; and (3) removing the AMI mandate from 2012. It is noted that our analysis has focussed on the costs to Victorian electricity customers, and does not include costs to Government or taxpayers due to the AMI Program.

Key conclusions

The key conclusions of our review are as follows:

- Over 2008-28, the Victorian AMI Program will result in net costs to customers of \$319 million (NPV at 2008). This reflects a significant change from previous cost benefit analyses undertaken, the most recent of which concluded that the AMI Program would deliver net benefits of \$775 million.² This change is driven by the fact that costs have significantly increased since the previous forecasts, benefits have been reduced and barriers to the early provision of AMI services have further slowed benefit realisation.

Comparison to previous analysis of the AMI Program



² Oakley Greenwood, *Benefits and costs of the Victorian AMI Program - Final Report*, August 2010. It is noted that the total benefits calculated by Oakley Greenwood were updated subsequent to the release of this report (from \$2 577 million to \$2 640 million). Deloitte has relied upon the final Oakley Greenwood Benefits Model.

- Despite our findings that the AMI Program will deliver a net cost to customers, we acknowledge that not all possible benefits of smart meters have been quantified in our review. AMI creates a platform for changing the way electricity is delivered to customers. As market participants, policy makers and customers experience and understand the potential of AMI over time, it could deliver additional benefits in network operations and energy management that are as yet unknown.
- A large proportion of the AMI Program costs will be 'sunk' or incurred by distributors by the end of 2011, yet most benefits are yet to be realised. Accordingly, our analysis has concluded that, given the progress of the rollout, continuing the AMI Program from 2012 will result in net benefits to customers of \$713 million (NPV at 2012).
- Should the Victorian Government decide to remove the AMI mandate from 2012, it is most likely that distributors would continue to install AMI for new customers and for meter replacement.³ This will result in lower costs, but also lower benefits. This scenario reduces the benefits from \$713 million to \$343 million, a reduction of \$371 million.

Results of Deloitte analysis

		AMI Program 2008-28 (NPV at 2008)	Continuing the AMI Program from 2012 (NPV at 2012)	Slowing the pace from 2012 (NPV at 2012)
Total costs	<i>in \$m</i>	2,349	1,572	1,394
Total benefits	<i>in \$m</i>	2,030	2,285	1,736
Net	<i>in \$m</i>	-319	713	343

- Although our analysis of the scenario resulting from a Government decision to remove the AMI mandate concludes with net benefits, we consider this scenario to be high risk. Under this scenario, customer acceptance of smart meters is at risk, along with many of the benefits of AMI. It is difficult to predict customer responses with certainty. We have not incorporated the costs of customer refusal to accept smart meters (and the resulting impact to lower benefits) in our analysis.

³ Following a Government decision to remove the AMI mandate, we acknowledge that a number of scenarios are possible and that responses may vary among the distributors. However, given the current state of the AMI rollout and trends in meter supply and manufacturing internationally, we consider our assumption that distributors will continue to install AMI meters for new and replacement sites is appropriate.

6. Regardless of any decision to continue the AMI Program or remove the AMI mandate, an immediate and sustained Government-led customer engagement program is needed to prevent cost increases and enable customers to realise the benefits of the investments made to date.⁴ Without customer engagement, costs will most likely increase and benefit realisation is at high risk. We recommend that Government plays a lead role in addressing safety concerns and promoting the benefits of AMI relating to energy and network efficiency. In conjunction with industry, Government should consider undertaking customer engagement on innovative tariffs and demand management services facilitated by AMI.
7. The governance of the AMI Program needs to be improved to drive benefit realisation and ensure risks are managed.
8. Regulatory and retail/distribution interface barriers to benefit realisation must be immediately resolved.
9. We have identified several risks that, if realised, could worsen the economics of the AMI Program. These risks relate to effective deployment and utilisation of the AMI technology and a lack of effective customer engagement.

Background: The Victorian AMI Program

The AMI Program has been developing and evolving since 2004, when it was first recognised by the Victorian Government that replacing the existing stock of basic accumulation meters with meters that can record electricity use in half hour intervals would enable more efficient pricing and assist Victorians to better manage their energy consumption.

It was then also recognised that adding communications technology as part of the meter replacement would bring considerable operating efficiencies to the distribution networks and allow Victoria to move towards a 'smart grid.' Eventually, specifications were determined for the rollout of AMI, led by the Victorian distribution businesses, for the period from 2009 to 2013. All Victorian electricity customers commenced paying for the AMI rollout from January 2010.

The smart meters have a range of functions, including recording consumption in 30 minute intervals, remote meter reading, remote connection and disconnection, as well as a network (Home Area Network, or HAN) enabling new smart appliances to connect to the meter to facilitate home energy management.⁵ The functions of smart meters will generate efficiencies in network operations, improving the reliability and quality of electricity supply. The AMI Program enables innovative network and retail tariffs and demand management services, which will encourage peak demand reduction and improve the efficiency of the network and may reduce the need to build peaking generation plants.

The distribution businesses have made different decisions regarding the selection of the appropriate communications technology. They have also made different choices regarding the back office IT systems to enable them to receive and manage the significant amount of data delivered by AMI.

⁴ Our analysis of the costs of the AMI Program does not incorporate the costs of this customer engagement program.

⁵ This report refers to AMI services of 'remote connection and disconnection,' which should be taken to mean the distributors' services of 'remote energisation and de-energisation.'

Our approach to calculating costs and benefits

We have undertaken our review of the AMI Program in consultation with key industry stakeholders, and using the most up to date information on each distributor's rollout. We have carefully reviewed the previous analyses of the AMI Program and applied some adjustments to the calculations of costs and benefits, updating inputs where appropriate.

It is important to note that, given the current state of the AMI Program, our calculations have assumed that a significant customer engagement program is undertaken from late 2011. Customer engagement is needed to confront community concerns regarding smart meter safety and to enable customers to utilise the smart meters and voluntarily adopt innovative tariffs and demand management products to deliver benefits associated with energy efficiency and peak demand reduction. In our view, without an immediate and sustained Government-led customer engagement program being undertaken, there is a risk that AMI costs could increase substantially due to customers refusing to have AMI meters installed and the majority of AMI benefits could be further delayed or lost.

We have also assumed that some retailer-distributor interface issues that are currently preventing customers receiving AMI services will be resolved by 2012, through Government intervention by establishing agreed processes and resolving other outstanding issues.

Our analysis of the impact of a Victorian Government decision to remove the mandate for the Victorian distributors to roll out AMI assumes that the distribution businesses will continue to install AMI meters and equipment, such that all small customers will receive an AMI meter by 2027. Accordingly, this scenario is titled 'Slowing the pace.' We consider that given the current state of technology and the extent of the infrastructure already installed, it is unlikely that there would be a return to basic accumulation meters following removal of the AMI mandate.

It is noted that while our analysis of 'Slowing the pace' results in net benefits (though less than continuing the AMI Program), there are also considerable risks under this scenario. The cost of this scenario depends highly on the degree of customer rejection of smart meters following the cancellation of the AMI Program, which we have not reflected in our calculations. While we consider that distributors and retailers will voluntarily move towards offering innovative tariffs and demand management products regardless of the AMI Program continuing or being cancelled, the level of customer engagement in these tariffs and products (and the resulting energy efficiency and peak demand reduction benefits) are at risk, should the AMI Program be cancelled.

Cost analysis over 2008-28

AMI Program costs

In forecasting the total AMI Program costs over 2008-28, we drew heavily on the distributors' confidential submissions and budget templates for the AMI budget period 2012-15 (which included actual and forecast cost data over 2009-11).

The distributors' proposals are currently being assessed by the Australian Energy Regulator (AER), whose final decision on the budgets and AMI charges for 2012-15 will not be made until the end of October 2011. We have made some adjustments to the proposed costs to reflect our views on the likely costs that will be approved by the AER and passed through to customers. These adjustments reduced proposed program management costs in 2014 and 2015, noting that the rollout will have been completed in 2013. However, our adjustments to proposed

costs reflect our views on the ability of the AER to reject costs under the AMI cost recovery framework (Order in Council (OIC)).

To calculate AMI Program costs from 2016, we have relied on international benchmarks of the ongoing operating costs of AMI, and allowed for declining real capital costs as the market for AMI metering develops. We have included costs for the replacement of AMI meters and related communications equipment, expecting that a replacement cycle that mirrors the initial AMI rollout will occur from 2024. We have also allowed for AMI related IT equipment expenditure to recur over 2016-28.

It is noted that while we have conducted our analysis based on the most recent cost estimates, it is still subject to some uncertainty with regard to the implementation of the technology. Future costs will depend upon advancements in technology for IT and metering and costs could vary from our estimates.

Other costs required to achieve benefits

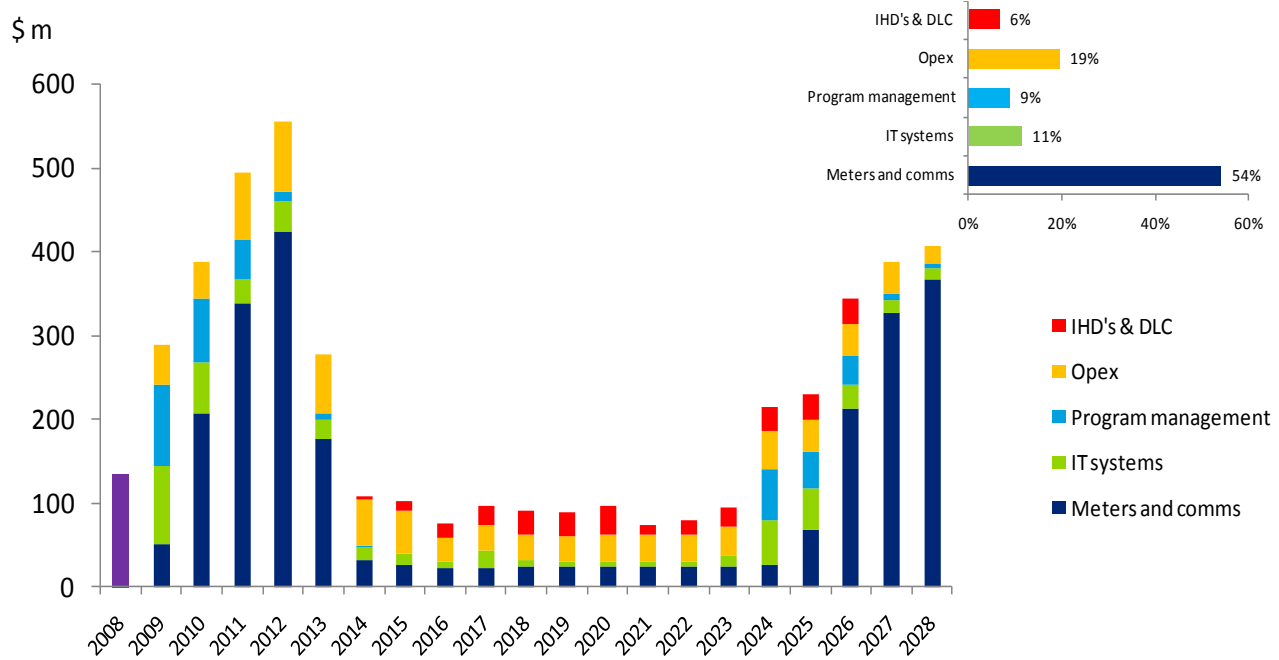
Our analysis has focused on the costs and benefits of the AMI Program to Victorian electricity customers. Aside from the network costs passed through to customers, there are some additional costs that we consider need to be incurred by customers and Government in order to achieve the benefits we have assumed.

- Community engagement program – We have assumed a targeted, sustained AMI customer engagement program is undertaken from late 2011. We have not included the costs of this program in our analysis, as we consider it could be funded by Government, rather than electricity customers.
- In home displays (IHDs) – Consistent with previous analysis of the AMI Program, we have included the costs of IHDs, allowing for up to 25% of Victorian customers to receive an IHD from 2020.
- Direct load control devices – We have incorporated the costs associated with supplying and installing direct load control devices in customer air conditioners, again allowing for up to 25% of Victorian customers to receive a direct load control device from 2020.

Cost profile

The diagram below illustrates the profile of AMI Program costs over 2008-28.

Total AMI Program Costs over 2008-28 (\$2011)



Note: 2008 costs are total, terminal values (ordinarily subtracted in 2028) have not been subtracted in this graph in order to show total profile of AMI costs

The following table presents our cost estimates by the key cost categories.

Total AMI Program costs by cost categories

Cost category	Total cost (\$ m)	(NPV at 2008, m)
Meters and communication	2 440	1 135
IT systems	512	261
Program management	393	250
Opex	874	456
IHD's & DLC	292	113
2008 total costs	134	134
Total	4 644	2 349

Note: 2008 costs are difficult to segment into the various categories. Terminal value has been incorporated in the NPV values.

The total AMI Program cost NPV of \$ 2 349 million is split into the following three time periods as follows:

- 52% of the costs are incurred in NPV terms over the period 2008-11 (these costs are largely approved by the AER).

- 32% of costs in NPV terms are projected to be incurred over the period 2012-15.
- 18% of costs in NPV terms are projected to be incurred over the period 2016-2028 (terminal value benefits have been included in this period).

Benefits analysis over 2008-28

Our analysis of the benefits likely to accrue to customers due to the AMI Program involved reviewing the previous analysis undertaken by Futura and Oakley Greenwood, updating parameters based on current market development and technology and applying relevant international and local benchmarks.

Based on international experience, we also considered which benefits of smart metering were not included in the previous analysis and have noted where some material but currently not quantified benefits are likely to accrue. Work to quantify some of these benefits is to be undertaken in Work Stream 2.

AMI Program benefits were analysed within four main categories:

1. Avoided costs associated with accumulation meters resulting from the AMI Program
2. Benefits derived from efficiencies in network operations
3. Benefits generated by innovative tariffs and demand management
4. Other smaller benefits (incorporating minor efficiencies in network and retail operations).

The following table presents the results of our benefit analysis as compared to the previous analyses.

Total AMI Program benefits (NPV at 2008, \$m)

Benefit category	Oakley		
	Futura	Greenwood	Deloitte
Avoided costs resulting from AMI Program	855	855	802
Benefits derived from efficiencies in network operations	1 029	956	587
Benefits generated from innovative tariffs and demand management	413	498	490
Other smaller benefits	343	280	151
Total	2 640	2 588	2 030

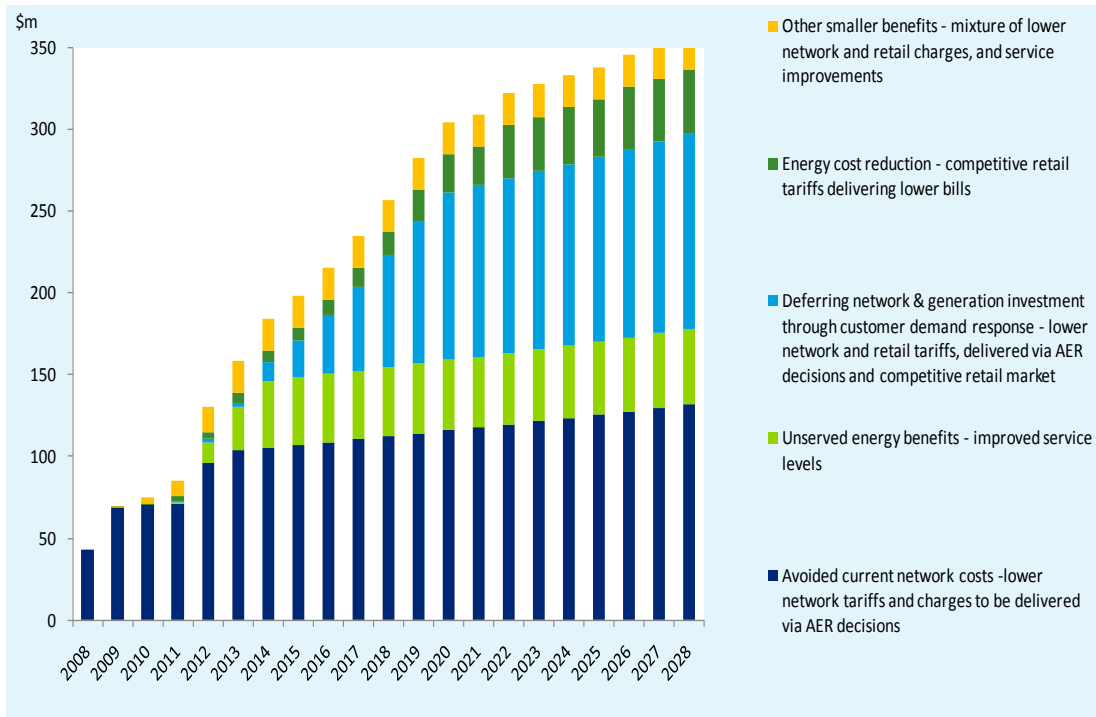
The main differences between our benefit analysis and the previous work include:

- Network efficiency benefits associated with improved outage detection were reduced to reflect our views on the feasibility of the previous assumptions, given the current state of distribution outage detection and response
- Benefits associated with load sharing at times of emergency were reduced, based on our understanding of the technology capability and customer response
- The mix of benefits generated from innovative tariffs and demand management was revised, with benefits associated with time of use tariffs reduced and the assumptions on critical peak pricing amended to incorporate incentive payments for critical peak responses

- A range of smaller benefits were removed from the analysis, due to our views on double counting between benefits and feasibility of the benefit delivery.

The following figure demonstrates the profile of estimated benefits over 2008-28.

Estimated benefit realisation over 2008-28

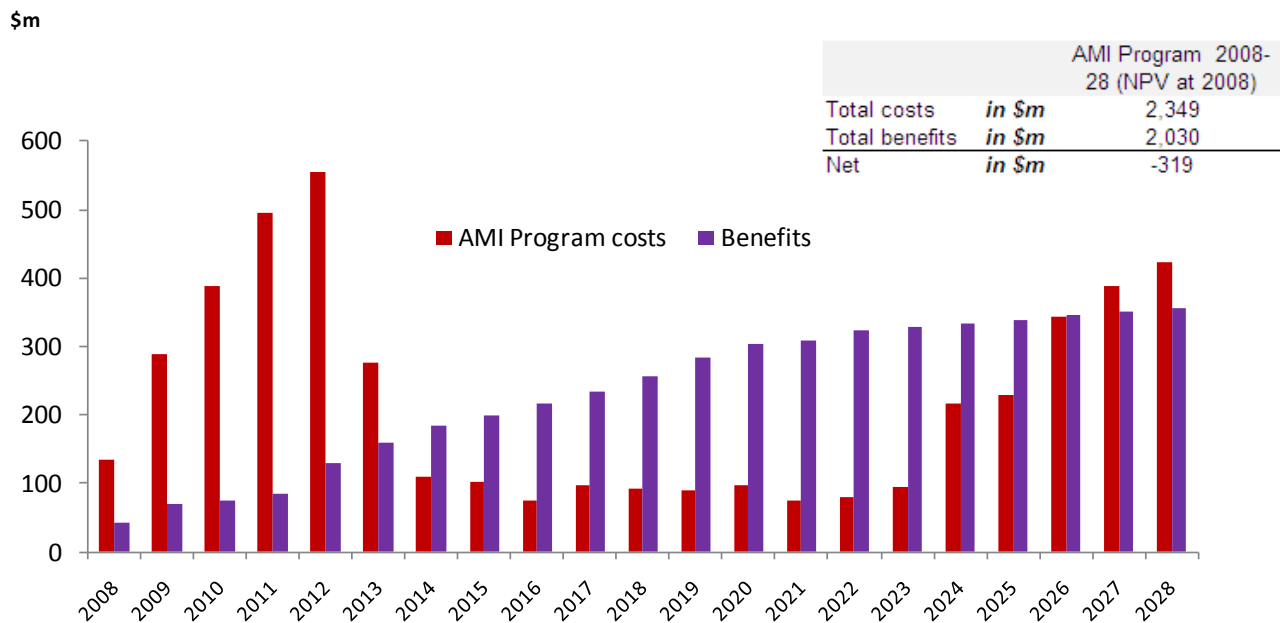


As this figure suggests, there are several ways in which AMI benefits will accrue to customers over 2008-28:

- Avoided cost benefits are already being realised by customers, as lower meter reading costs and accumulation meter capex are being passed through to customers via the AMI charges determined by the AER (although given the AMI costs and accelerated depreciation of accumulation metering is also driving the AMI charges, this reduction in network costs is not obvious as yet)
- Benefits driven by innovative tariffs, network and generation cost deferral and improved service levels will be realised after 2013, once the rollout is complete
- Many of the benefits will require regulatory changes and depend upon customer response to electricity prices and other incentives.

The following figure contains our conclusions on AMI Program costs and benefits over 2008-28.

Conclusion - Total costs and benefits of the AMI Program over 2008-28



Forward looking analysis from 2012

Our review has concluded that continuing with the AMI Program from 2012 will deliver a net benefit to customers of \$713 million (NPV at 2012), while 'Slowing the pace' will deliver a net benefit of \$343 million (NPV at 2012). This suggests that continuing with the AMI Program will result in the best outcome for customers.

Costs

While our 'Continuing the AMI Program' cost analysis is based on the total AMI Program costs, minus sunk costs, our forward looking analysis under the "Slowing the pace' scenario is based on the following key assumptions:

- Despite the removal of the AMI mandate, distributors are able to recover the costs of installing AMI meters on a new and replacement basis from 2012-15, following which metering will be incorporated with other distribution assets for regulatory purposes
- Distributors will complete the implementation of their AMI communications and IT infrastructure over 2012-13 (which is largely complete by the end of 2011), and continue to install AMI meters on a new and replacement basis.

Benefits

As most of the benefits are yet to be realised, the 'Continuing the AMI Program' benefits are similar to those of the total AMI Program over 2008-28, with a 13% increase due to the impact of shifting the net present value from 2008 to 2012. It is noted that, consistent with the analysis of the AMI Program over 2008-28, the estimated benefits in the 'Continuing the AMI Program' scenario are based on the assumption that a targeted, sustained AMI customer engagement program is undertaken from late 2011.

Under the 'Slowing the pace' scenario, benefits differ according to the categories established above:

- All AMI Program avoided cost benefits will be fully realised over 2012-28 as we have assumed the total stock of meters is replaced by 2027
- Benefits derived from efficiencies in network operations will be realised in line with the gradual rollout of AMI meters
- Benefits generated by innovative tariffs and demand management will be affected by customer sentiment, pushing the achievable demand reductions and energy efficiency four years into the future
- Smaller benefits will be realised in proportion to AMI meters installed.

In determining the benefits under the 'Slowing the pace' scenario, we have also assumed that a customer engagement program is undertaken.

As noted above, we consider that the 'Slowing the pace' scenario involves significant risks, which if they eventuate, could significantly reduce net benefits. These include risks associated with a significant customer backlash and rejection of smart metering technology and the potential for a lack of customer engagement which would reduce the benefits delivered by innovative tariffs and demand management.

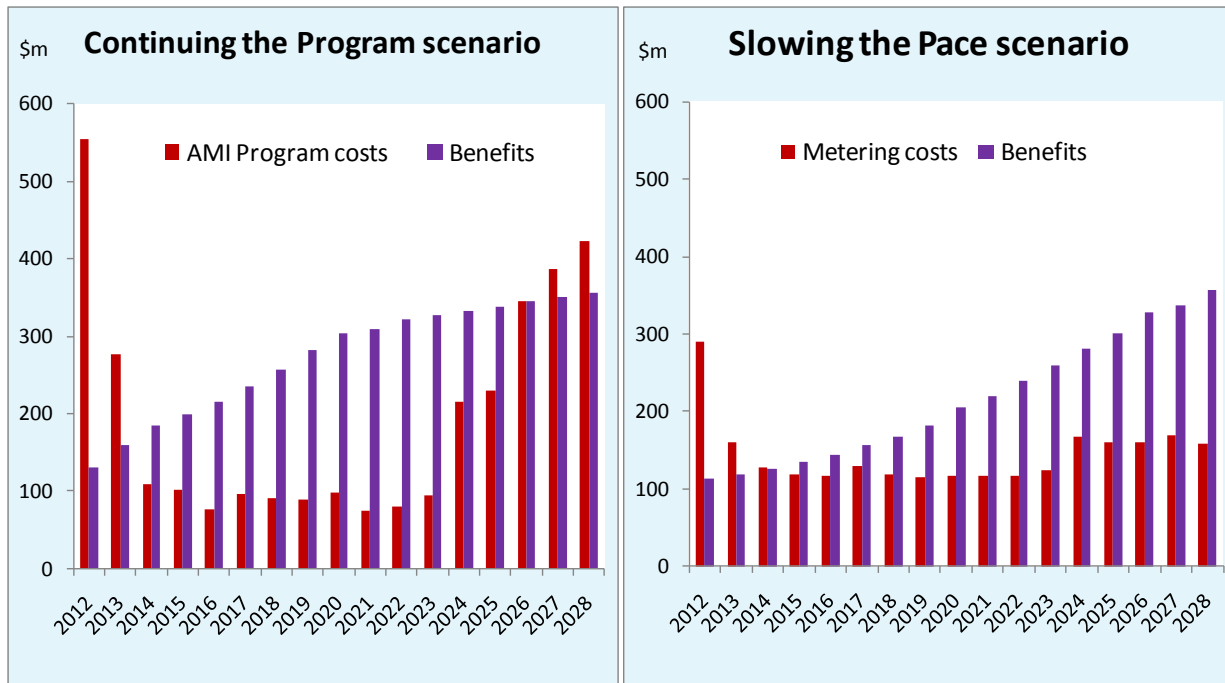
Conclusion – forward looking analysis

The following table outlines the results of our forward looking analysis.

Scenarios from 2012 – 'Continuing the AMI Program' and 'Slowing the pace'

NPV (at 2012, million, \$2011)	Continuing the AMI Program	Slowing the pace
Total costs	1 572	1 394
Total benefits	2 285	1 736
Net benefits	713	343

The following figures demonstrate the estimated profile of costs and benefits of each scenario over 2012-28.



Risks of cost increases

We have identified the following risks to the estimated costs of the AMI Program:

1. Technology risks—Of the AMI meters installed to date, less than 30% are ‘live’ and communicating with the distributors.⁶ Any problems with the performance of the technology could increase costs to customers. In addition, any changes to the radio frequency on which the distributors’ communications systems operate (as is currently being considered by the Australian Communications and Media Authority) could lead to significant cost increases.
2. Regulatory incentive risks—The AMI cost recovery framework enables the distributors to overspend on their approved budgets by up to 10% for 2012-15, without triggering a review by the AER. Given they have overspent by on average 14% over 2009-11 (where the threshold for 2009-11 is 20% before triggering a review), we consider this is a potential risk. Also, there are risks associated with transitioning AMI from a cost pass through framework to the National Electricity Rules regulatory framework from 2016, where a base year is used to determine on-going operating allowances.

In addition, we consider there is a significant risk of cost increases related to customer opposition to the AMI Program. We have assumed that the customer engagement program will reduce this risk, however if customer engagement is not undertaken, costs due to customers rejecting the technology will be incurred.

⁶ AMI Deployment Dashboard, June 2011

Comparison to previous analyses

The results of our analysis are significantly different from previous reviews of the costs and benefits of the AMI Program. There are two key drivers of this difference:

1. Our analysis of costs is based on the distributors' 2012-15 AMI Budget Proposals, submitted to the AER in February 2011. Prior to these proposals, the analysis of the total AMI Program costs were based on lower cost estimates. In addition, we have included some IT system costs as AMI Program costs, which were previously considered to be business as usual.
2. We have revised downwards some of the benefits previously estimated, based on our discussions with stakeholders.

Enhancing the benefits of the AMI Program

In calculating the benefits of the AMI Program for Victorian electricity customers, we have assumed a number of steps to improve the AMI Program are undertaken in the latter half of 2011. These recommendations will be further developed in the next phase of our work:

1. Customer engagement program: As discussed above, a targeted, sustained customer engagement program is needed to realise the benefits associated with innovative tariffs and demand management
2. Removing the barriers to remote connection and disconnection: At present, one of the key benefits of AMI is not being realised by customers due to a liability issue between retailers and distributors. By resolving the issues preventing remote connection and disconnection, customers will be able to commence receiving the benefits of the AMI Program. Our analysis of the benefits of the AMI Program has assumed that this barrier is removed by the start of 2012
3. Developing a process framework for connection of in home displays: There is currently no process to enable customers to connect in home displays to their AMI meters, meaning that retailers are unable to offer in home displays to their customers. Enabling this connection will facilitate customer engagement in the AMI Program and deliver benefits. Our analysis of the benefits of the AMI Program has assumed that this barrier is removed by the start of 2012

In addition, in undertaking our cost benefit analysis a number of further options to modify and potentially improve the AMI Program have been identified. The impacts of these additional options on the costs and benefits of the AMI Program have not been included in our cost benefit analysis. These options will be investigated further within the next phase of our work:

1. Improve AMI Program governance: Our review has highlighted problems with the AMI Program that suggest the overall governance of the rollout needs to be improved. Improving governance would enable issues such as the barriers to remote connection and disconnection and in home displays to be avoided, or resolved in a more efficient manner. This recommendation is consistent with that made by the Victorian Auditor General.
2. Encourage the deployment of in home displays: They have the potential to deliver a tangible understanding of the AMI Program to customers. By encouraging or facilitating the deployment of in home displays, the Victorian Government could improve customer engagement and enhance the benefits of the AMI Program.

3. Revise the AMI cost recovery arrangements to reduce 2012-15 costs: Revising the cost recovery arrangements and improving the ability of the AER to more closely scrutinise costs and apply international benchmarking could reduce the costs of the AMI Program for customers. However, significant work to understand the implications of such changes is required.
4. Amend the rollout timeframe requirements to avoid the most costly areas: International experience of smart meter rollouts suggests that the most expensive and difficult areas to install and remotely connect are left to the final stages, and the costs associated with connecting them are often (a) well above those for other areas, and (b) significantly underestimated by utilities. The AMI OIC requires that by 31 December 2013, the distributors roll out remotely read interval meters to, as far as practicable, 100% of Victorian customers. This requirement could be eased by either reducing the required percentage coverage, or providing a longer time period to connect the most difficult areas (by which time lower cost solutions may be available). While these options will also eliminate some benefits, the benefits lost may be significantly outweighed by the costs avoided. We recommend analysis of the costs and benefits of lowering the requirement to roll out meters to 100% of customers by 2013.

1. Introduction

1.1 Context

The former Victorian Government mandated a program for the accelerated rollout of advanced metering infrastructure (AMI, also referred to as smart meters) in February 2006. The AMI Program involves the replacement of older accumulation meters with new meters in approximately 2.66 million Victorian homes and small businesses.

Victorian electricity Distribution Network Service Providers (referred to in this report as distributors) are responsible for installing smart meters and consumers pay for AMI Program-related costs through the metering services charge determined by the Australian Energy Regulator (AER) and incorporated in a customer's electricity bill.

The rollout commenced in 2009, and is due for completion in 2013. As at 1 June 2011, more than 650,000 smart meters had been installed across Victoria.

Key elements of the regulatory framework supporting the rollout are found in Division 6A of the Electricity Industry Act 2000 and two Orders in Council made under that Division (the AMI Cost Recovery Order (OIC) and the AMI Specifications Order).

Victorian consumers commenced paying for the AMI meters on 1 January 2010, and have paid between \$160 (United Energy Distribution (UED) customers) and \$270 (Jemena Electricity Network (JEN) customers) over 2010-11.⁷ The AMI Program requires the AER to set separate annual metering charges until 2016 when the AMI cost recovery framework expires and metering services rejoin other distribution assets under the AER's 2016-20 distribution determination for Victoria.

1.2 Terms of reference

In accordance with a letter from the Department of Treasury and Finance (DTF) dated 30 May 2011, Deloitte has been appointed by DTF to undertake a reassessment of the costs and benefits of the AMI Program. Our objective was to determine the likely costs and benefits to be realised by Victorian electricity customers due to the AMI Program, and identify ways to improve the realisation of benefits for customers.

DTF outlined two separate Work Streams. This report reflects the outcomes of Work Stream 1. Work Stream 2 will involve more detailed assessment of the identified options to enhance the AMI Program. Our analysis within this report includes the following three elements:

1. A cost benefit analysis of the AMI Program for the period 2008 to 2028 (referred to as the AMI Program lifecycle analysis)
2. Forward looking analysis to estimate the cost and benefits of
 - a. continuing the AMI Program as currently mandated from 1 January 2012, and

⁷ AER, *Decision – Advanced Metering Infrastructure - 2011 revised charges*, October 2010. Note that this includes the cost of the continual installation of accumulation meters in some cases, and the accelerated depreciation of the old metering stock.

- b. removing the Government mandate for the AMI rollout from 31 December 2011
3. Identifying and analysing options which could improve customer benefits and/or minimise AMI Program costs.

1.3 The Deloitte and WorleyParsons team

We partnered with WorleyParsons to ensure that the team had the required expertise in the technical aspects of this review. The combined team of Deloitte and WorleyParsons has brought together all of the required expertise, as follows:

- Deloitte – Electricity network regulation, energy retail and generation markets, financial and commercial analysis expertise, prior smart metering analysis
- WorleyParsons – AMI and smart metering technology, distribution network operations and metering.

1.4 Report structure

The remainder of this draft report is structured as follows:

- Section 2 provides background information on the DTF's review of the AMI Program, the history of AMI in Victoria and other states and legislative arrangements supporting the Victorian AMI rollout
- Section 3 provides an outline of the AMI technology deployed in Victoria and the current status of the Victorian AMI rollout
- Section 4 presents a cost benefit analysis of the AMI Program over 2008-28, including the base case, AMI costs and benefits. It also discusses some risks of cost increases to the AMI Program, and presents some high level sensitivity analysis of our key assumptions
- Section 5 presents an analysis of the forward looking costs and benefits of the AMI Program from 2012, testing the likely impact of two key Government decisions – continuing the AMI Program, and removing the AMI mandate ('Slowing the pace')
- Section 6 outlines the options we have identified for enhancing the net benefits of the AMI Program, which are to be analysed further as part of Work Stream 2
- Appendix A presents our detailed assumptions.
- Appendix B contains two key reports on AMI benefits and international smart meter rollouts.

2. Background

2.1 Department of Treasury and Finance Review of the AMI Program

This report forms part of a broader review of the AMI Program being conducted by the DTF, including a public consultation process currently underway. The DTF published an Issues Paper on 31 May 2011 (*Review of the advanced metering infrastructure program-Issues paper for public consultation*), which sought stakeholder comments on a number of issues discussed in this report. In forming the advice in this report, Deloitte has reviewed submissions to the DTF Issues Paper.

In addition, during the review Deloitte consulted with the key stakeholders outlined in Table 2.1, to obtain their views on a broad range of issues related to the AMI Program. This consultation was extremely useful in testing our assumptions and seeking input on the outcomes of the AMI Program to date and possible AMI Program scenarios for 2012 and beyond.

Table 2.1: Stakeholders consulted during our review

Distributors	CitiPower Pty (CitiPower) and Powercor Australia Limited (Powercor)
	Jemena Electricity Network (JEN)
	United Energy Distribution (UED)
	SP AusNet Pty Ltd (SP AusNet)
Retailers	AGL Energy Limited
	Origin Energy
	TRUenergy Pty Limited
	Simply Energy
	Lumo Energy
Customer advocacy groups	Consumer Utilities Advocacy Centre
	Consumer Action Law Centre
	Alternative Technology Association
	Brotherhood of St Lawrence
Government agencies	Department of Primary Industries
	Australian Energy Regulator

2.2 History of AMI in Victoria and other jurisdictions

This section outlines the development of the Victorian Government's decision to replace the existing accumulation metering stock in Victoria with smart meters. Victoria was the first jurisdiction in Australia to consider a state-wide rollout of smart meters, preceding the National Smart Meter Project (NSMP).

Box 1 provides a description of the general meter types referred to in this report.

Box 1: Definitions of accumulation meters, interval meters and smart meters

Accumulation meter

The most common type of meter is the 'accumulation meter'. It records energy consumption over time. Consumer premises are visited regularly to read the meters and assess how much power has been used in a billing period. Tariff structures which operate under accumulation meters can include single-rate tariffs, which means the consumer pays the same price per kWh regardless of when electricity is used, and dedicated circuit (controlled load) tariffs, where an off-peak meter is tied to specific appliances such as hot water that work only at certain times. Where an off-peak meter is also in operation, a lower price is paid on electricity used by these dedicated circuits. Tariffs are usually structured at either a flat rate or with an inclining block, that is, where the price of electricity rises past a predetermined point of use.

Interval meter

An interval meter records energy use over short intervals, typically every half hour. This allows suppliers to settle promptly on wholesale prices and to better understand and manage the pattern of electricity demand, thus enabling flexible pricing to reflect demand and cost of supply. Tariff structures typically associated with interval meters are 'time-of-use' (TOU) tariffs, where electricity use is charged according to the time at which it is consumed.

Smart meter

The smart meter is more advanced than the interval meter as it allows remote communication between the electricity supplier and the meter, enabling the supplier to deliver efficient and innovative services to consumers such as real-time display of usage information and automated control of power levels in appliances such as air-conditioners. Tariff structures typically associated with smart meters are TOU tariffs, where electricity use is charged by the time at which is consumed. However, it is possible to maintain flat tariffs where a customer has a smart meter.

Source: Victorian Auditor General (2009) 'Towards a Smart Grid – the roll-out of Advanced Metering Infrastructure', accessed online: http://download.audit.vic.gov.au/files/111109_AMI_Full_Report.pdf, last accessed 14 May 2011

2.2.1 ESC 2004 decision on mandatory rollout of interval meters

In 2004, the Victorian Essential Services Commission (ESC) mandated the rollout of manually read interval meters throughout Victoria, termed the 'Interval Meter Rollout' (IMRO) program. The Commission's decision to mandate a rollout of interval meters was predicated on the following assessments:

- Market forces alone would fail to deliver a timely interval meter rollout on a scale sufficient to provide economies in meter manufacture, installation and reading
- Regulatory intervention would be required to achieve the economic benefits that would result from a more timely and larger scale rollout
- Based on the Commission's cost-benefit analysis, a net economic benefit would arise from a timely, mandatory rollout of interval meters
- The existing differential between the cost of accumulation and interval meters was expected to fall over time.⁸

2.2.2 Victorian Cabinet 2006 approval of the new AMI mandate

In view of developments in metering technology and the possibility that the IMRO decision could be expanded to deliver greater benefits to customers, the then Department of Infrastructure (DOI), together with the electricity

⁸ See Essential Services Commission, Mandatory rollout of interval meters for electricity customer, Final decision, July 2004, p2. Available at: http://www.esc.vic.gov.au/NR/rdonlyres/8FCF80D2-F7EB-4071-9C7F-A0721A95B004/0/IMRO_FinalDecisionFinal9July04.pdf

distributors and retailers, commissioned a cost-benefit study in 2005 to examine the net societal benefits of adding advanced functionality to the IMRO mandate. The study consultants, CRA International and Impaq Consulting, established a societal business case for adding two-way communications and core advanced functionality – remote meter reading and remote connection and disconnection – to the IMRO mandate, and conducting the rollout according to an accelerated four year schedule. The original communications technology recommended was distribution line carrier (DLC).

According to CRA / Impaq, at best, the revised metering plan would produce benefits of \$432 million and costs of \$353 million, while at worst, benefits would remain at \$432 million and costs could increase to \$954 million (NPV at 2005).⁹

Cabinet approved the new Advanced Metering Infrastructure (AMI) mandate (also known as AIMRO) in early 2006. An amendment to the *Electricity Industry Act 2000* was passed in August 2006 providing the Government with legislative heads of power to make Orders-in-Council (OIC) establishing requirements for the AMI deployment.

As a consequence of the Victorian Cabinet decision, AMI was to be installed in all residential and small business premises over four years, commencing in 2009. Enabling legislation was established, and a specific AMI cost recovery framework established (following several amendments over 2007-09). Technology trials were also conducted to determine the functionality and performance level specifications to be mandated for Victoria.

2.2.3 MCE sponsored 2008 national smart metering analysis

In April 2007, the Council of Australian Governments committed to a national roll-out of electricity smart meters to areas where benefits could be demonstrated to outweigh costs. A national AMI cost-benefit report prepared by NERA, released in mid-2008, informed this national decision. On the basis of the NERA analysis, a distributor-led rollout of AMI in Victoria was estimated to offer net benefits in the range from negative \$101 million to positive \$690 million (NPV at 2007).¹⁰

The National Smart Metering Program (NSMP) established a leadership body (the National Stakeholder Steering Committee) to facilitate consistent technical and operational development of smart meter rollouts. Jurisdictional ministers in each state were tasked with determining whether to implement smart meter rollouts under the NSMP framework. The Australian Energy Market Commission (AEMC) has recently provided advice to the MCE on the cost recovery arrangements for future smart meter rollouts (which would not affect the Victorian AMI rollout). The AEMC advised that the current National Electricity Rules framework could adequately accommodate the recovery of efficient costs for mandated smart metering infrastructure (including rollouts or pilots and trials), subject to some incremental amendments to the National Electricity Rules being made.¹¹

⁹ CRA International and Impaq Consulting (for DoI), Advanced Interval Meter Communications Study, December 2005. Available at: <http://share.aemo.com.au/smartmetering/Document%20library/Smart%20meter%20background%20info/AMI%20Communications%20Study%20Draft%20Final%20Report.pdf>

¹⁰ Ibid.

¹¹ See NERA Economic Consulting (for MCE) 'Cost Benefit Analysis of Smart Metering and Direct Load Control, Overview Report for Consultation', February 2008, p87. Available at: http://www.ret.gov.au/Documents/mce/ documents/SmartMetering%20BAPhase2Stream1_overviewNERA20080305175957.pdf

¹² See AEMC, *Final Report - Request for Advice on Cost Recovery for Mandated Smart Metering Infrastructure*, 30 November 2010. Available at: <http://www.aemc.gov.au/Market-Reviews/Completed/Request-for-Advice-on-Cost-Recovery-for-Mandated-Smart-Metering-Infrastructure.html>

To date, no states have determined to mandate the rollout of smart meters under the NSMP (although some distributors in other states are conducting large smart meter and smart grid trials, partly funded by government, as discussed in section 2.4). While the Victorian AMI rollout moved ahead of the NSMP, there is considerable Victorian involvement in the NSMP. NSMP plans are being developed to ensure the Victorian AMI Program is consistent with the national framework, where appropriate.

2.2.4 Victorian Auditor-General's criticism of AMI decision making process

The cost-benefit analysis that supported the Victorian decision to mandate the rollout of AMI (commissioned in 2005 by DoI), was subject to criticism by the Victorian Auditor-General's Office (VAGO) in 2009. VAGO's conclusions and main findings included the following:

The AMI project has not used the checks and balances that would ordinarily apply to a major investment directly funded by the state. This highlights a gap in the project's accountability framework.

There have been significant inadequacies in the advice and recommendations provided to government on the roll-out of the AMI project. The advice and supporting analysis lacked depth and presented an incomplete picture of the AMI project in relation to economic merits, consumer impact and project risks.

The cost-benefit study behind the AMI decision was flawed and failed to offer a comprehensive view of the economic case for the project. There are significant unexplained discrepancies between the industry's economic estimates and the studies done in Victoria and at the national level. These discrepancies suggest a high degree of uncertainty about the economic case for the project.

2.2.5 DPI sponsored 2009 – 2010 review of AMI costs and benefits

In response to the VAGO criticism, DPI commissioned further analysis of the benefits and costs of the AMI Program in 2009 and 2010. This involved separate analysis of benefits (conducted by Futura) and costs (conducted by EMCA).

The review culminated in the release of a report by Oakley Greenwood that concluded the AMI rollout would deliver low case benefits of \$2.577 billion against expected costs of \$1.813 billion (\$2008).¹⁴

The Oakley Greenwood report has, itself, been subject to a review sponsored by DPI and conducted by Deloitte. In late 2010, Deloitte was engaged to review whether the Oakley Greenwood work aligned to Victorian Government guidance material on best practice. The Deloitte review found that although the Oakley Greenwood work effectively articulated the cost and benefits of the project, the work could have been enhanced by more closely following the Victorian Government guidelines in relation to clearly defining the base case and incorporating analysis around the impacts on different types of stakeholders.

¹³ See Victorian Auditor General (2009) 'Towards a 'smart grid' – the roll-out of Advanced Metering Infrastructure', pp viii-ix. Available at: http://download.audit.vic.gov.au/files/111109_AMI_Full_Report.pdf last 4 June 2011

¹⁴ See Oakley Greenwood for DPI (2010) Victorian Smart Meter Cost Benefit Analysis Report. This report incorporated an acceptance of the costs as estimated by EMCA and a review the benefits as estimated by Futura Consulting. Available at: <http://www.new.dpi.vic.gov.au/smart-meters/cost-benefit-analysis/victorian-ami-program>

2.3 Victorian AMI rollout – Legislative and regulatory framework

In mandating the rollout of AMI, the former Victorian Government determined minimum functionality and service level specifications to which the distributors' AMI solutions had to conform. Four key services were specified for the rollout period (noting that additional services may be provided post rollout):

- Recording of energy imported or exported from a metering point by half hour trading interval
- Remote reading of the AMI meters
- Remote de-energisation
- Remote energisation.¹⁵

Minimum functionality and performance levels for the AMI systems were determined according to the following elements:

- Meter configurations
- Remote and local reading of meters
- Supply disconnect and reconnect
- Time clock synchronisation
- Load control
- Meter loss of supply detection and outage detection
- Quality of supply and other event recording
- Supply capacity control
- Interface to the home area network (HAN).¹⁶

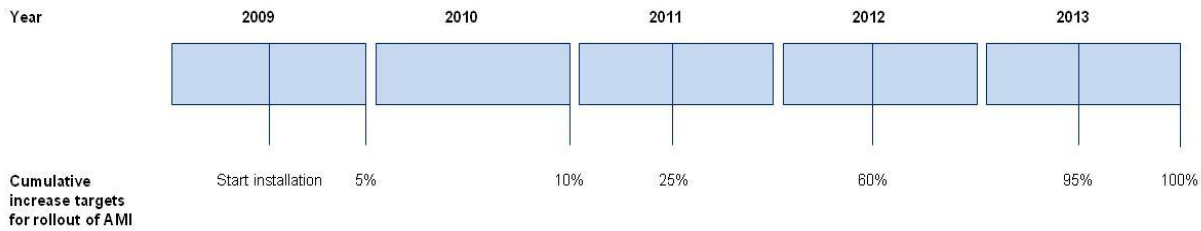
The Victorian distributors commenced rolling out AMI meters and communications and IT infrastructure in late 2009. While there are differences among the distributors in the progress of their individual rollouts, approximately 650 000 AMI meters had been installed at the end of May 2011, along with a significant portion of the communications equipment necessary to enable the meters to transmit data. The majority of the IT capex required to support the large volumes of AMI data, organise and manage the rollout has also been incurred.

Figure 2.1 illustrates the rollout schedule stipulated within the AMI Order in Council (OIC), which the Victorian distributors are required to meet (and which is a condition of their distribution licences). Each percentage target represents the proportion of meters that must be installed and capable of being remotely read.

¹⁵ DPI, *Minimum AMI Service Levels Specification (Victoria), Release 1.1*, September 2008. The full functionality of AMI metering is specified in DPI, *Minimum AMI Functionality Specification (Victoria), Release 1.1*, September 2008. Available at: http://new.dpi.vic.gov.au/_data/assets/pdf_file/0014/13109/Minimum-AMI-Functionality-Specification-Victoria.pdf

¹⁶ Ibid.

Figure 2.1: Regulatory targets for AMI rollout



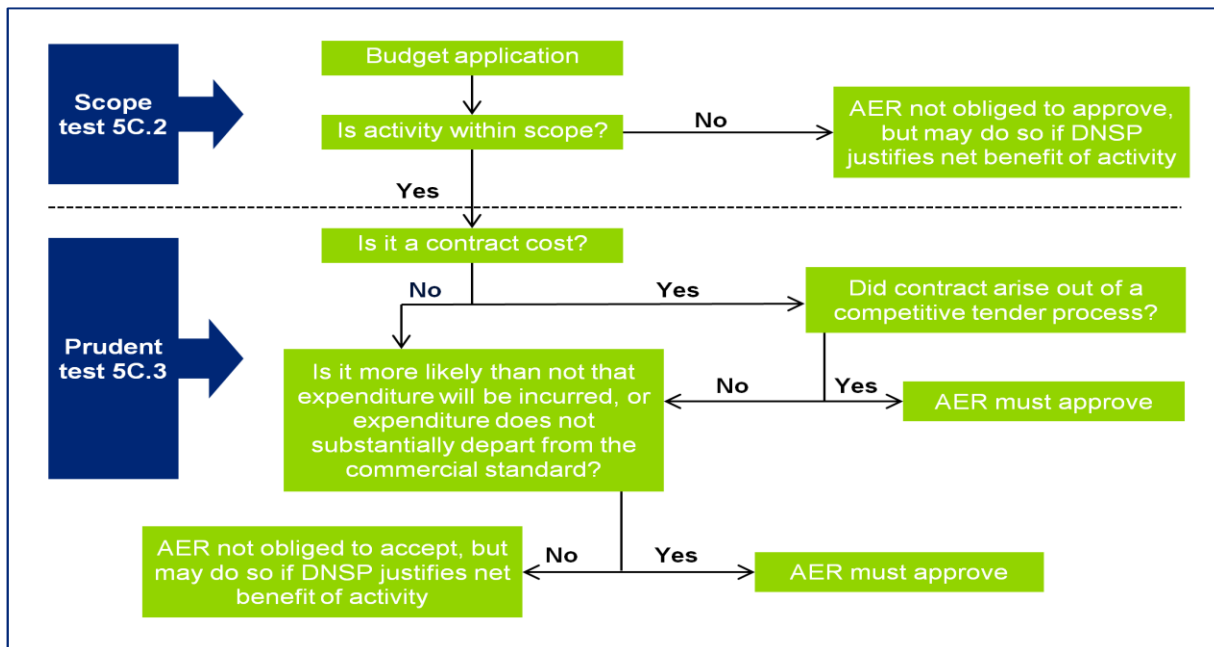
Source: Victorian Auditor General (2009) 'Towards a Smart Grid – the roll-out of Advanced Metering Infrastructure', accessed online: http://download.audit.vic.gov.au/files/111109_AMI_Full_Report.pdf, last accessed 14 May 2011. Note that the percentages required to be achieved at each stage of the rollout are subject to the qualifier 'or as close as is practicable.'

As Figure 2.1 demonstrates, the rollout of AMI meters is expected to significantly accelerate from the second half of 2011, with over 75% (approximately 2 million) meters to be installed and commissioned (able to be remotely read) in the next 30 months.

The AMI OIC sets out the regulatory and cost recovery framework for the interim rollout period over 2009-15. Cost recovery is split into two budget periods, over calendar years 2009-11 and 2012-15. From 2016, metering will again become part of the distributors' Regulatory Asset Bases (RAB), and will fall under the National Electricity Rules.

The cost recovery framework within the AMI OIC is best described as a cost pass through arrangement, which differs significantly from the incentive regime under the National Electricity Rules to which other distribution assets are subjected. Approximately 10 months prior to the commencement of each Budget Period, distributors were required to submit applications outlining their forecast AMI budgets and associated customer charges to the AER. The OIC states that proposed budgeted costs must be approved, unless the AER can establish that they do not meet a series of tests, as set out in Figure 2.2.

Figure 2.2: AMI Order in Council – Budget tests



Source: AER, *Final determination- Victorian advanced metering infrastructure review - 2009–11 AMI budget and charges applications*, October 2009, p. 3.

For the 'Scope test', the AMI OIC requires that activities associated with the proposed costs must be those that are required to deliver metering (AMI and accumulation metering) services. Broad lists of specific 'in scope' activities associated with the distributors' obligation to roll out AMI are contained in the AMI OIC.

For the 'Prudent test', the relevant tests that the AER must apply are dependent upon whether the cost is associated with a signed contract that has been competitively tendered. Where this is the case, the cost is automatically approved. Where costs are 'non-contract', they are also automatically approved unless the AER can establish that either the cost is more likely than not to not be incurred, or that the expenditure will be incurred but that incurring it involves a substantial departure from the commercial standard that a reasonable business would exercise in the circumstances.

The AER Approved Budgets are converted into separate charges for metering via a 'building block' methodology. It is worth noting the following key points:

- All Victorian small customers commenced paying for their AMI meters as at 1 January 2010
- Only actual incurred costs are paid by customers. There is an annual process whereby the AER adjusts the charges set in its 2009-11 or 2012-15 AMI Budget Decision to ensure only actual costs are passed through to customers. Distributors must provide independent auditor statements that detail actual costs, and where actuals differ from the Approved Budget, can seek to recover up to 120% of the Approved Budget costs in 2009-11, and 110% of the Approved Budget costs for 2012-15 without triggering a review by the AER
- The AMI OIC provides that distributors may elect to under-recover their costs over 2010-15. All distributors have elected to under-recover over 2009-11, and JEN has also elected to under-recover its AMI costs over 2012-15
- Recovery of costs for the distributors' accumulation meter asset bases is accelerated as part of AMI charges over 2010 to 2015.

2.4 Smart meter trials and pilots in other states

While the NSMP continues to develop plans for mandated smart meter rollouts, pilots and trials, some distributors have moved ahead to trial new metering infrastructure.

2.4.1 ETSA Utilities

Following extensive research and trials of technologies to reduce peak demand, South Australian distributor ETSA Utilities is now trialling up to 1,000 Peakbreaker+ devices throughout the Adelaide metropolitan area and a regional area.

The Peakbreaker+ program is a refinement of earlier direct load control schemes. A communications module is fitted alongside the customer's conventional electricity meter and is capable of controlling air conditioning compressors on a rotational basis. It has two way radio communications, which offers a range of additional features to its load switching capability.¹⁷

¹⁷ ETSA Utilities, *Demand Management Program Interim Report No. 3*, June 2010.

2.4.2 Ausgrid

2.4.2.1 Smart Grid Smart City

In mid-2010 a consortium led by NSW distributor Ausgrid (formerly EnergyAustralia) won the tender for the Australian Government's \$100 million 'Smart Grid Smart City' project.¹⁸

The three-year project runs across five sites in Sydney and the Hunter Valley (Newcastle, Scone, Sydney CBD, Ku-ring-gai and Newington). It will represent Australia's first commercial-scale smart grid, and is one of the largest and most integrated smart grid projects anywhere in the world.

The consortium has committed to rolling out up to 50,000 smart meters to homes across the trial sites. The technology will allow residents to see real-time analysis of electricity usage for their households, as well as for individual appliances. The smart grid demonstration will also test real-time, complex data on grid performance in order to the efficiency and control of network operations for energy transmission and distribution companies.

2.4.2.2 Smart Village and Smart Home trial

Ausgrid has also undertaken to build Australia's first Smart Village and Smart Home as part of a two-year trial, aimed at helping 1,000 households in Newington and Silverwater (NSW) reduce their utility bills and carbon impact. This trial is partly funded by the NSW Government's Climate Change Fund.¹⁹

Homes in the trial are being connected to a smart grid featuring greater information and control of energy consumption. These households will be able to obtain real time data on their energy and water use, turn their appliances on and off remotely using iPhones and websites, and compare energy use through neighbourhood competitions. A Smart Home is also being fitted out in Newington to test the latest energy and water efficient appliances and how renewable energy interacts with the grid.

2.4.2.3 Smart meter trials

Independent of the two Government funded trials, Ausgrid has also been rolling out smart meters and time of use pricing to a subset of its customers as part of its move towards a smart grid.

More than 4,000 smart meters with communications have been installed to date, and about 200,000 customers have been involved in time of use tariff trials.²⁰

2.4.3 Essential Energy

NSW distributor Essential Energy (formerly Country Energy) has been involved in smart grid and smart meter trials since 2004. Essential Energy conducted Australia's first demand management trial including smart meters, in-home displays, and critical peak pricing tariffs.²¹

¹⁸ The consortium consists of technology companies including Smart Grid Australia members IBM, Newcastle City Council and GE Energy Australia, as well as AGL Energy, Sydney Water and Hunter Water.

¹⁹ Ausgrid website – Smart Grid Facts. Available at: <http://www.ausgrid.com.au/Common/Network-projects/Network-projects/Smart-grid-projects/Smart-grid-facts.aspx>

²⁰ Ausgrid website – Smart Grid Facts. Available at: <http://www.ausgrid.com.au/Common/Network-projects/Network-projects/Smart-grid-projects/Smart-grid-facts.aspx>

²¹ Essential Energy website – Quick facts. Available at: <http://www.intelligentnetwork.com.au/content/quick-facts-country-energy-is-transforming-the-electricity-distribution-network.aspx>

The trial involved around 150 customers in and around Queanbeyan, NSW. The trial confirmed the importance of real time consumption data in driving energy efficiency. Customers involved in the trial achieved an overall reduction in energy consumption and up to 30 per cent reduction in their peak demand. Essential Energy has noted that education was key to the success of the trial, helping customers maximise the benefits of the technology to save on their costs and cut greenhouse gas emissions.

2.4.4 Western Power

Western Australian distributor Western Power has been trialling smart meters across its network as part of a number of projects.

As part of its Green Town Project, which aims to trial multiple energy efficiency initiatives, Western Power has installed more than 1500 smart meters.²²

In addition, the Perth Solar City project involves trialling smart meters for 8700 residents in the East Metropolitan area. At the end of this project, Western Power has indicated that it will evaluate the trial results and make decisions on the roll out of smart meters to the remainder of its network.

2.5 International smart meter rollouts

There are many examples of smart metering programs around the world, however the technical features of the smart metering devices installed vary greatly between rollouts.

Italian distributor Enel has carried out the world's largest rollout of smart meters, with 27 million meters deployed. Unlike the Victorian AMI meters, Enel's smart meters do not have Home Area Network capability.

In Texas, several utilities are deploying smart meters concurrently, however, unlike in Victoria, their meters do not have the ability to remotely connect and disconnect customers.

In California three major utilities will complete deployments of more than 10 million smart meters by mid-2012.

The following tables provide selected examples of international smart meter rollouts which share some characteristics with the Victorian AMI Program.

Table 2.2. HydroOne – Ontario, Canada

Location details	Electricity distributor HydroOne in Ontario Canada serves 1.2 million customers that inhabit 2 million square kilometres of Ontario. The network area includes some small cities, towns and all of the rural areas in Ontario. HydroOne is also responsible for all of the transmission network construction and maintenance for Ontario.
Number of meters installed	As of June 2011, 1.2 million smart meters are installed and communicating remotely.
Timeframe for rollout	Meter testing was carried out from 2004 to early 2006. A first scale test of deployment was completed in late 2006, and the full deployment of smart meters

²² Western Power website. Available at: http://www.westernpower.com.au/aboutus/mediaCentre/mediaReleases/2010/Smart_meter_trial_starts_in_Denmark_and_Walpole1.html

started in early 2007. The Ontario Government mandated that meters were to be installed before the communications network, and as such the first 700,000 meters were deployed ahead of the network. In 2010 the vast majority of the smart meter and communications network deployment were completed. HydroOne is currently carrying out network tuning and the final 3% of the meter installation. This is expected to be completed in early 2012.

Technology adopted Initial smart meter testing involved a older mobile phone technology called GSM from the communication vendor Smart Sync, of which 25,000 meters were deployed. Once this meter testing was complete, HydroOne decided to use Trilliant's communications network (mesh radio) for 95% of customers and Aclara's power-line carrier for the final 5%. The Aclara system has had very limited rollout in practice accounting for less than 1% of the customers instead of the planned 5%.

Customer engagement HydroOne started an extensive customer engagement program in the summer of 2004, setting up booths at community agriculture fairs and other community events, including information on bills and sending customers letters in business envelopes. HydroOne carried out extensive questioning on incoming calls to its call centres and offered its executives for radio and television interviews. The smart meter program was branded with logos which were added to HydroOne employee shirts and trucks including the phrase "Ask Me About it?".

Before TOU pricing commenced (which is mandatory in Ontario), another round of communication was sent to customers, such that in most cases each customer had 3 to 5 examples of various smart meter and then TOU pricing information from HydroOne. Smart meter specific 24 hour call centres were established, with specially trained staff to answer inquiries. Customer questions that could not be handled by the call centre staff were personally responded to by HydroOne executives, including the program director or the CEO.

Results As at June 2011, 1.2 million smart meters are installed and operating, and approximately 900,000 customers are on TOU transmission and distribution charges, while being free to choose a retailer for energy pricing. All HydroOne customers will be on TOU tariffs by the end of October 2011

HAN Similar to Victoria, a Zigbee home area network (HAN) was deployed within the meters. Approximately 2000 homes now have Zigbee thermostats and another 1,000 have in-home displays (IHDs).

A specific HAN engagement program was carried out, including a lived in demonstration HAN-home. The demonstration home has had over 10,000 visitors to see over 50 Zigbee devices in action, including a remote pet feeder. The HAN engagement program has involved a major home building company that has agreed to build fully HAN equipped housing in Ontario.

Other features Similar to Victoria, HydroOne's smart meters communicate consumption data to market daily, however they do not have remote connection and disconnection

capability. Prior to the rollout, HydroOne customers faced quarterly bills.

Significant cost increases above budget included a 24 hour operations centre that was not initially anticipated.

Table 2.3. Southern California Edison (SCE), California

Location	<p>Californian utility SCE covers the area outside of the City of Los Angeles, from just north of San Diego to north and west of LA. SCE has one of the fastest growing customer bases in the US, adding an average of 50,000 customers a year.</p> <p>SCE's network area includes what were rural areas in the late 1940s and early 1950s, while the older cities and towns each have their own municipal utilities. SCE also owns and operates a gas network that does not match its electricity network. Accordingly, SCE's network area is inconsistently covered by SCE, which has complicated its smart meter rollout.</p>
Number of meters installed	<p>At last report over 4 million smart meters were installed and communicating in SCE's network. The total deployment objective is 5 million meters.</p>
Timeframe for rollout	<p>SCE commenced testing smart meters in 2004, and similar to Italian distributor Enel, decided to design its own meter. However, this was abandoned in late 2005 and SCE settled into a long testing period, involving almost every meter vendor in its field trials.</p> <p>In 2006 a decision was made to deploy Itron's OpenWay system and a customer pilot was undertaken in early 2007. During the pilot, Itron upgraded the meter and communications capability, creating OpenWay 2.0. This upgraded technology was supported by another electricity and gas distributor which borders SCE to the south, with some scale and scope efficiencies generated.</p> <p>Building on the lessons learned from HydroOne's rollout, SCE opened its operations centre early in the rollout and started operating the communications network almost immediately.</p>
Technology adopted	<p>SCE adopted Itron's OpenWay communications system with a combination of G3 and Fibre Optic backhaul from the collectors in the field. The communications system is mesh radio based, and uses an unlicensed 900Mhz frequency, (which is identical to the Silver Springs mesh radio).</p>
Customer engagement	<p>SCE followed Hydro One's example with extensive pre-rollout communications to its customers, and extensive follow up communications, including a personal phone call from the call centre to each customer where a meter was installed.</p>
Results	<p>SCE has more than 4 million meters communicating data to market daily.</p>

HAN

The SCE deployment also includes a Zigbee based HAN. The HAN is not active in the meters today, aside from in a handful of SCE-employee homes. SCE expects to start enabling the HAN for customers who sign up in late 2011 or early 2012.

Other features

Similar to Victoria, SCE's smart meters feature remote connection and disconnection capability, and a Zigbee HAN. SCE's network operations centre is staffed 24/7 with outage information being immediately routed to SCE's Outage Management System.

SCE has a web portal where customers can see their own usage data, and has released an iPhone and Android app that allows customers to get their consumption data on their smart phones or iPads.

Unlike Victoria, prior to the smart meter rollout, SCE manually read its customers' meters on a monthly or more frequent basis. Accordingly, the business case for the smart meter rollout was largely substantiated by the reduction in manual meter reading costs. It is noted that SCE's meter reading costs included significant costs associated with staff injuries, with California being the highest cost location in the world for settling industrial injuries. In some cases, a dog bite has cost SCE over US\$1 million.

3. Technology deployed in Victoria

This section provides a detailed outline of the wireless communications technologies that the Victorian distributors are deploying as part of their AMI rollouts, and our analysis on the appropriateness of these technologies in meeting the mandated Victorian AMI specifications. It also provides a summary of the current status of each distributor's rollout, based on the June 2011 AMI Deployment Dashboard.

3.1 Communications technology

In Victoria, two major types of smart metering systems have been deployed by the distributors. The first is based on technology created by Silver Springs Networks (SSN), and the second is based on technology created by GridNet. GridNet technology is being deployed by SP AusNet, while the remaining four distributors are deploying the SSN network.

3.1.1 WiMAX and GridNet

Associations or trade alliances such as WiMAX, WiFi, Zigbee and Bluetooth are made up of manufacturers and users that have agreed upon a standard set of protocols, channel definition, channel spacing, and security mechanisms that have been found compliant and interoperable with other devices.

WiFi is a very successful alliance, based upon the IEEE 802.11 standard, which is responsible for the proliferation of small, short range wireless networks in homes and offices. It is important to note that these alliances do not govern the use of any particular radio band and in the case of non-licensed frequencies, often have to compete for available bandwidth from other technologies.

WiMAX (Worldwide Interoperability for Microwave Access) is also an alliance, capable of operating on many different frequency bands, primarily 2.3, 2.5, 3.65 and 5GHz. The IEEE 802.16 covers spectrum ranges from at least 2 GHz through 66 GHz.

WiMAX, the basis for the communications system installed by SP AusNet, is an Internet Protocol (IP) based Device to Device (P2P) wireless protocol with defined quality of service requirements. GridNet has taken advantage of WiMAX protocols and standards to create communications networks such as that deployed by SP AusNet. WiMAX, like WiFi is based on an IEEE standard, in this case IEEE 802.16.

Product literature suggests coverage ranges approaching 48 kilometres for WiMAX. It is our view that, while this may be possible under ideal conditions, 5 to 16 kilometres is more realistic for fixed installations (IEEE standard 802.16 d), or 5 to 8 kilometre range for mobile applications (IEEE 802.16e). However, these estimates can vary widely depending on antenna height, antenna type, local terrain, urban environment, ground conditions and local topography as these have a major impact on the range of a base station at any given location.

In terms of data throughput (or data transfer rates), in theory WiMAX could support up to 200 megabytes per second (Mbs) per channel. However, based on the anecdotal evidence to date, the reality is closer to 25 Mbs and at longer ranges, it is about 5 Mbs.

WiMAX offers speed or distance, but not both. An endpoint close to a base station may see effective rates of 45 Mbs, while an endpoint at the edge of the coverage cell may only see data rates of 1 to 2 Mbs. As distance

increases, the number of incorrect messages received on each end of the communications link also increase, resulting in requests to retransmit the message. This rapidly reduces the effective data rate of WiMAX.

The complexity of setting up a WiMAX network can be compared to the complexity of setting up a new mobile phone network. Towers, fibre optics for backhaul, network management software, backup generators, and other equipment, as well as installation and tuning, are similar to that required in the deployment of a commercial phone network.

WiMAX, like a mobile phone network, can support multiple connections to devices at the same time. In the network of WiMAX that GridNet selected, approximately 200 devices can communicate with a tower at one time. It is noted that not every device will communicate at exactly the same time, but towers are capable of remembering 200 devices that they want to communicate with at one time.

3.1.2 900Mhz and SSN

Another option for communications is a 900 MHz system. Unlike WiMAX which operates within a defined community standard, most 900MHz systems are custom designed by the vendor with little regard for interoperating with other vendors' equipment.

900 MHz systems are available for licensed and unlicensed frequencies. 900 MHz offers better penetration capabilities through walls and vegetation than the longer range WiMAX operating in the gigahertz bands. In general, the lower the frequency, the better the distance and penetration capabilities. Gigahertz frequencies tend to be very reflective, bouncing off trees, houses and other obstacles more so than the 900 MHz band.

In Victoria, SSN selected an unlicensed part of the radio spectrum and shares that spectrum with other unlicensed devices like baby monitors, wireless phones, taxi dispatchers and others. Because of the very short messages sent by the meters, frequency regulators have allowed the SSN system to use more power than most other equipment in this unlicensed spectrum. That provides a longer range, and fewer incorrect communications.

Unlike the GridNet system, where the meter communicates directly with the tower, the SSN system involves individual meters communicating with each other (mesh). As messages 'hop' between meters, eventually messages are passed to a collection system. This method of communicating reduces the power and complexity required for the data collection system and also reduces the overall cost of the collection system. It does, however, require more collection points than GridNet's WiMAX system.

Mesh is an architectural configuration that allows endpoints to act as repeaters for other endpoints that would normally be out of range of the base station or access point. It is an effective method of extending the range and reducing the number of collection points required. Theoretically, the number of hops (transmissions between endpoints) can be in the hundreds, however in practice, if transmissions exceed two or three hops before arriving at a collection point, excess latency and other issues emerge. Unlike mesh communications from many other vendors, SSN mesh is "shallow", keeping transmission to 3 to 5 hops in a fully formed area.

Mesh adds robustness to a communications network, allowing for multiple paths in and out of geographic areas. This technology is moving towards a 'self-healing' or adaptive network, able to route around problems until they can be corrected.

Typical data rates for 900 Mhz systems range from 10 to 250 kilobits per second (Kbs), however some systems can deliver more than 1000 Kbs. The SSN mesh system can achieve data rates of up to 100 Kbs, however given

each meter needs to listen for communications from its neighbours and information from the collection points, the effective throughput of the SSN system is approximately 20 Kbs.

3.1.3 Capabilities

In our view, both the GridNet and SSN communications networks are fully capable of meeting the Victorian Government's AMI specifications, and both systems have potential benefits and capabilities beyond the minimum Victorian specifications.

The GridNet (WiMAX) communications system has enough bandwidth and short enough turn around on messages (latency) that the system could be used for downloading data to utility vehicles in the field, and potentially for sending System Control and Data Acquisition (SCADA) messages. Additionally the GridNet system has the capability to provide limited broadband capacity in remote areas, such as remote substations or wind farms. The GridNet system also has sufficient bandwidth to move security information from remote equipment.

The SSN communications system is capable of routing messages around equipment with problems and reforming its network in a different fashion to limit the impact of communication equipment outages. If SCADA equipment is situated close to mesh collection points, and is capable of communicating directly with the collection points, the SSN system could support SCADA.

3.1.4 Security

Security and data privacy are important considerations for smart metering deployments. In the case of GridNet, the WiMAX standard has a minimum operating requirement for encryption that exceeds the minimum standard set by most security regulators. In addition GridNet has selected a stronger version of encryption for their system and provided a "firewall" like capability in each piece of equipment that increases the difficulty of a hacker getting into a device.

SSN built its own security from the ground up, including security in the design of the system. SSN's communications network also exceeds the minimum encryption standards, but unlike GridNet, does not have that additional "firewall" like capability.

To date, neither SSN nor GridNet have reported any major breaches of security. However, like any computing device, both are subject to attempts by hackers to compromise their devices. Both GridNet and SSN subscribe to the US Department of Energy's NESCOR[1] security system and have been active in setting up methods for managing vulnerabilities until they can be patched.

Firmware upgrades of the GridNet system should take approximately a week per 100,000 meters in the field. A similar firmware upgrade carried out on the SSN network can take 2 to 3 weeks.

As GridNet's system is built on top of an alliance standard, it has the support of the alliance in finding and fixing software that is used as part of the common transport protocol. By contrast, SSN is responsible for its own firmware updates.

3.1.5 Summary

In our view, from a technology performance standpoint, due to the longer range and the additional capabilities within the GridNet communications system, SP AusNet's decision to employ GridNet as its AMI communications system is reasonable. Similarly, the deployment of SSN by the other Victorian distributors is also a reasonable

decision. All of the distributors appear to have selected communications systems which exceeded the Victorian Government’s minimum specifications, and both systems were, at the time they were selected, leading vendors of meter communications technology.

However, as is discussed in detail below (risks of cost increases), the most recent data on the performance of the AMI rollout suggests that problems may be emerging in enabling the AMI communication systems for certain distributors.

3.2 AMI Program status

The progress of the Victorian AMI Program varies widely among the distributors. All of the distributors are making progress with the physical installation of AMI meters, however there are vast differences in the reported numbers of meters meeting the requirement for ‘Logical meter exchange,’ which occurs when the meter is registered in the market as a remotely read interval meter that provides interval data to market on a daily basis.

Table 3.1 outlines the latest available data on the distributors’ AMI rollouts, as reported to DPI at the end of June 2011.

Table 3.1. June 2011 AMI Deployment Dashboard statistics

Distributor	AMI meters installed	Total number of Logical meter exchanges completed	% of Logical meter exchanges per AMI meters installed
CitiPower and Powercor	342 957	1 864	1%
JEN	64 774	62 388	96%
SP AusNet	161 541	2	0%
UED	137 015	127 102	93%

Source: AMI Deployment Dashboard, June 2011. Provided to Deloitte by DPI.

3.2.1 JEN and UED

The joint JEN – UED AMI rollout continues to move forward at the required regulatory pace, and is by far the most progressed rollout of the Victorian distributors’. The IT and interface systems are substantially in place and operating. The internal processes and procedures needed to operate the AMI network are in place and operating. Of the entire Victorian AMI Program, JEN and UED meters reflect the bulk of the meters that have completed the Logical exchange process.

Based on current installation rates and logical exchanges completed, both distributors are close to having 20% of the total expected meter population installed. Both distributors are reporting a lag of approximately 3 weeks between installation and Logical exchange, however we understand this lag is reducing as more meters are rolled out.

3.2.2 CitiPower and Powercor

As part of their joint AMI rollout program, CitiPower and Powercor continue to install meters at a pace that exceeds the installation requirements of the AMI OIC. Unlike JEN and UED, CitiPower and Powercor are completing the Logical exchange process for installed meters only once an entire area has been completed and the associated manual meter reading route can be discontinued. We understand that the AMI network and meters are communicating and data is being received by the distributors' Meter Data Management system.

While there have been very few Logical meter exchanges completed to date, given the decision to complete the rollout area by area, we expect that the current Logical exchange rate of less than 1% will rapidly improve as meter installation areas are completed. However, it is our understanding that CitiPower and Powercor's AMI processes and procedures have not been fully tested at scale and so some teething problems may also be slowing the overall rate of Logical exchanges.

3.2.3 SP AusNet

SP AusNet is installing meters in the field at a pace that falls just short of that required by the AMI OIC, and from a meter installation viewpoint, is on track.

However, SP AusNet has recently advised DPI that it will not be ready to meet the AMI OIC specifications of providing daily remotely read interval data to market, nor providing remote connection and disconnection until August 2012 (an eight month delay from that specified in the AMI OIC).

We understand that the issues causing this delay are related to SP AusNet's need to re-tender for Systems Integration. It appears a large number of questions surround SP AusNet's AMI rollout, from the implementation of WiMax in the field, to the implementation of the IT systems in the data centre.

It is notable that SP AusNet elected to install a modular meter, which means that should it decide to abandon the WiMax network and move to a different communications technology, only the communications card in the meter would need to be exchanged, avoiding the full cost of replacing meters.

4. Analysis of costs and benefits: 2008-2028

The key conclusions of this chapter are:

- Over 2008-28, the AMI Program will result in net costs to customers of \$319 million. This is a significant change from previous analyses of the AMI Program, the most recent of which suggested that the AMI Program would deliver \$775 million of benefits.
- This change is driven by the fact that AMI costs have increased, while total expected benefits have reduced and benefit realisation has been delayed.
- Our analysis assumes that from late 2011, a sustained customer engagement program is undertaken to address issues related to smart meter safety, and to engage customers on the tariff and non-tariff benefits of AMI. We have also assumed that current barriers to the provision of remote connection and disconnection services and in home displays are resolved by 2012.
- There are a number of risks that if realised, could substantially increase the costs of the AMI Program beyond that calculated by Deloitte. These risks are related to the performance of the AMI technology, the incentives within the AMI cost recovery framework and the transition to the National Electricity Rules from 2016.

4.1 Objective of analysis

The first element of our analysis was to re-evaluate the economics of the entire AMI Program as currently mandated, over 2008 to 2028. This involved reviewing the previous cost benefit analysis conducted by Oakley Greenwood in 2010 (and the prior analyses of the AMI Program costs and benefits that fed into Oakley Greenwood's work, by EMCa and Futura), and updating it to account for new information on costs and benefits.

Given the AMI Program is already underway, the objective of this entire AMI Program lifecycle analysis was to consolidate the previous cost benefit studies of the same period in line with new information and apply our own views on the cost benefit analysis approach, assumptions or calculations. This also provides a starting point for the second element of our analysis, being the forward looking analysis of the costs and benefits of continuing the AMI Program or removing the AMI mandate ('Slowing the pace') from 2012.

At present, there is growing reluctance in the Victorian community to embrace the AMI Program. This has the potential to significantly reduce the benefits and increase the costs of the AMI Program if community engagement is not undertaken immediately. Accordingly, our analysis of the benefits of the AMI Program has assumed that a

community engagement program is undertaken from the second half of 2011, to bring the AMI Program back on track. Our assumptions on community engagement are detailed in section 4.4.5.1.

Our analysis has focused on the costs and benefits of the AMI Program to Victorian electricity customers. As such, we have not included costs incurred by the Victorian Government, Australian Energy Regulator or consumer advocacy groups, noting that most of these costs are passed onto taxpayers. In addition, we have not included costs incurred by electricity retailers in preparing for and implementing AMI data and processes.

Given the competitive retail market, some proportion of these costs would have been absorbed by retailers, and some proportion passed onto customers. These proportions will depend upon the competitiveness of the market, the pre-AMI state of each retailer's IT and billing systems, and the extent to which retailers have plans to implement innovative tariff and energy management products and have leveraged some of their IT systems to do so.

4.2 Establishing the base case

4.2.1 Determining the appropriate scenario

In order to carry out a retrospective cost benefit analysis of any policy or decision, it is necessary to clearly articulate and calculate a base case (sometimes referred to as the counterfactual). The base case is typically the 'business as usual' scenario, whereby in the absence of the particular policy having been implemented, expenditure (or, for example, revenue, performance) would have continued along as it had been.

In determining the appropriate base case for our analysis of the AMI Program over 2008-28, it was noted that more than one 'business as usual' scenario for small customer metering in Victoria could be considered realistic. We identified two possible scenario streams, outlined in Box 2.

Box 2: Possible base case scenarios identified

Base case scenario 1

A continuation of the installation of manually read accumulation meters on a new and replacement basis (noting that most distributors were installing electronic, twin register accumulation meters that were capable of separately recording peak and off-peak usage, with a separate hot water off peak rate for customers with electric storage hot water systems)

Base case scenario 2

The gradual uptake of new metering technology (either manually read or remotely read interval meters) by distributors (or retailers) as the market for these more sophisticated meters evolves and they become cost-comparable to accumulation meters. It is noted that this scenario could incorporate the installation of manually read interval meters as per the ESC's 2004 IMRO decision, which was superseded by the AMI decision in 2006. The IMRO program would have involved an accelerated rollout of manually read interval meters to:

- a) All large customers (>160MWh per annum), by 2008
- b) Customers consuming between 20MWh and 160MWh per annum that have off peak metering or three phase metering, by 2011
- c) Customers consuming less than 20MWh per annum that have off peak metering or three phase metering, by 2013
- d) All remaining customers with single phase non-off peak metering on a new and replacement basis, starting from 2008.

After careful consideration and consultation with the DTF and the DPI, it was clear that the first (accumulation meter) scenario was the most appropriate base case for analysis of the AMI Program over 2008-28, for the following key reasons:

- While it is reasonable to assume that metering technology would have evolved away from accumulation metering in the absence of the AMI Program, to establish the costs of scenario 2 would require a significant number of assumptions, including:
 - a. Changes in metering, communications and related IT technology, and the development of markets for such technology
 - b. Distributor and retailer responses to changes in these technologies and their markets
 - c. Regulatory changes to deal with, encourage or simply enable the take up of new metering, communications and related IT technology (noting that the ESC's 2004 IMRO decision was overturned in 2006 due to the decision to move to more sophisticated remotely read smart meters, or AMI)
 - d. The timing in the 2008-28 period by which a, b and c would be expected to occur.
- Such assumptions are difficult to determine and defend, and serve to undermine the quality of the analysis of the AMI Program
- The previous cost benefit analyses of the AMI Program conducted by EMCa and Oakley Greenwood assumed an accumulation meter base case (although it is noted that neither had fully established the costs under the base case, but rather had removed some accumulation metering related costs/benefits from the AMI Program costs/benefits, as discussed below). Adopting an accumulation meter base case enables a direct comparison of our analysis with EMCa and Oakley Greenwood (subject to the comments below).

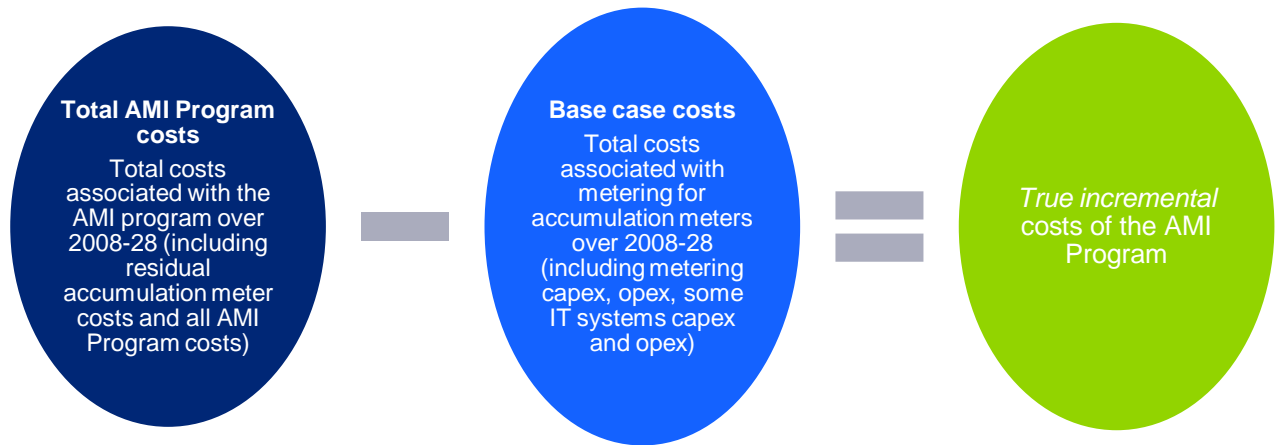
4.2.2 Calculating the incremental costs and benefits of the AMI Program

It is important to note that Deloitte's approach to cost benefit analysis has differed from the analysis carried out by EMCa and Oakley Greenwood.

The previous analysis of the AMI Program costs did not fully establish and calculate a base case to compare the AMI Program costs against. Instead, certain costs were removed from the calculation due the assumption that they would have been incurred under the base case. This approach is not in itself incorrect, however, we consider that it has led to some confusion on the true incremental costs of the AMI Program. It is noted that Deloitte did not receive any cost models used in the previous analysis, and instead has relied on the publicly available report and verbal advice provided by EMCa.

Deloitte's approach to cost benefit analysis differs from the previous work, in that a fully established accumulation meter base case for 2008-28 has been calculated separately to the full costs of the AMI Program over 2008-28. In order to determine the incremental costs of the AMI Program, the base case costs are subtracted from the AMI Program costs (as shown in section 4.5 below). The following diagram demonstrates the approach to calculating the incremental costs of the AMI Program.

Figure 4.1: Calculating the true incremental costs of the AMI Program



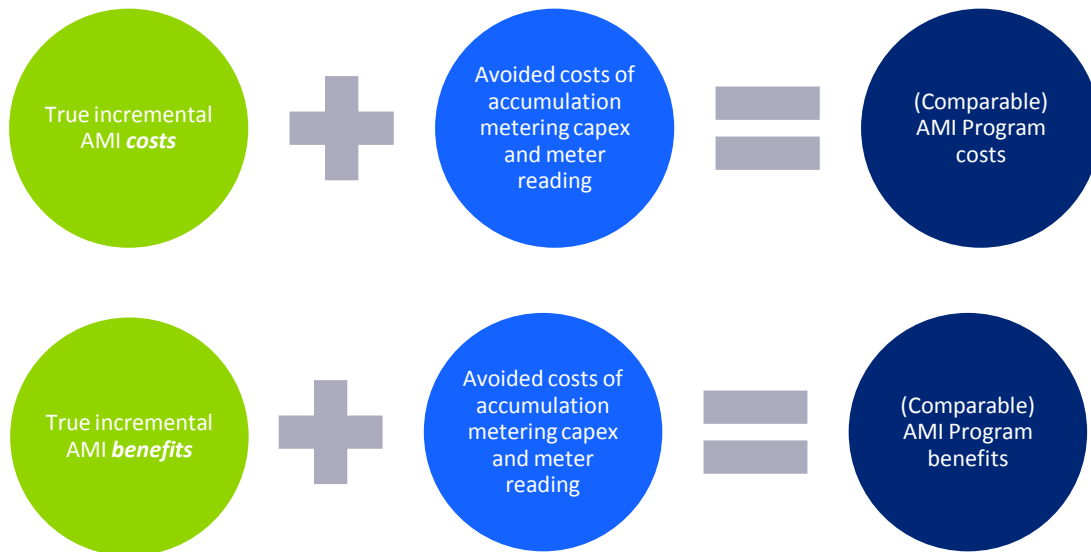
Due to this different methodological approach, in order to compare the previous cost benefit analyses of the AMI Program to Deloitte’s analysis, adjustments need to be made on both sides of the cost-benefit equation. This primarily relates to the treatment of avoided costs of meter replacement and meter reading that the AMI Program brings about.

Given our incremental cost approach, the avoided costs of accumulation meter reading and accumulation meter replacement are accounted for (subtracted from) the total AMI Program costs. In previous analyses of the AMI Program, these avoided costs were counted as benefits.

In principle, Deloitte considers that avoided costs are better accounted for in incremental cost calculations (as is done for other costs that are within the base case), rather than being added to the benefit side of the equation. However, in order to ensure our analysis is comparable to the previous studies and to avoid double counting, we have added the avoided costs of accumulation metering capex and meter reading back to the Incremental AMI Program costs. Accordingly, where this report refers to the total AMI Program costs, the avoided costs associated with accumulation metering capex and meter reading have been added to this equation to avoid double counting of the associated benefit when determining the NPV result of the AMI Program. It is noted that, as the avoided costs are added to both sides of the equation, this does not affect the calculated net cost/benefit result of the AMI Program.

Figure 4.2 demonstrates our treatment of avoided costs to enable comparison to EMCa and Oakley Greenwood’s analysis.

Figure 4.2: Calculating the costs of the AMI Program for comparison to previous analyses



4.3 Base case costs and benefits

4.3.1 Metering capital and operating costs

In order to establish the base case costs and benefits, we relied on publicly available information on the Victorian distributors' accumulation meter costs and functionality over 2001-09. This included data taken from regulatory decisions made by the Office of the Regulator General (ORG) in 2001, the ESC in 2006 and the AER's decision on AMI costs over 2009-11 (noting that this latter decision incorporates metering costs over 2006-08). Historical cost data on meter supply capex, meter reading, meter maintenance and meter data management opex were sourced from these decisions.

4.3.2 Customer service costs

It was also necessary to include some customer service costs which would have been incurred under the accumulation metering scenario. Customer service costs include metering specific call centre costs, and other customer support costs related to metering. Given it is not possible to extract historical customer service costs from the previous decisions mentioned above, our approach to estimating base case customer service costs differed among the distributors.

For CitiPower and Powercor, we have assumed annual customer service costs in the base case are equal to the customer service costs that were incurred in 2009 (the first year of the AMI rollout, when less than 1% of customers had AMI meters).

It was not possible to estimate the base case customer service costs for JEN, UED and SP AusNet using their own 2009 cost data. Accordingly, we have assumed an average customer service cost per customer for JEN, UED and SP AusNet equivalent to the weighted average of CitiPower and Powercor's customer service costs in 2009 (\$3 per customer).

4.3.3 Metering related IT costs

A proportion of IT that is being implemented (and costs recovered) under the AMI Program, while having been brought forward and enhanced due to the AMI rollout, would also have been implemented to some degree in the base case. In order to account for this, we have added the following costs from the AMI Program costs to the base case:

- **Meter data management (MDM) capex** – The distributors' budget templates included significant IT capex related to MDM, in most cases due to the implementation of an entirely new IT system to manage interval data. It is our view that, in order to implement the AMI Program, it is necessary for the distributors to procure new MDM systems to manage the interval data delivered by AMI. However, an AMI MDM system is approximately twice as expensive as that required under an accumulation metering scenario. Accordingly, we have assumed that 50% of proposed AMI Program IT capex for MDM would have been incurred under the base case. We have also allocated 50% of the MDM associated IT hardware costs from the distributors' AMI budgets
- **Customer Information Systems (CIS) capex** – Similarly, one distributor has included significant costs for a major upgrade of its CIS system within its AMI budget for 2009-15. We consider that while the AMI Program will require minor modifications to CIS, major upgrades are unnecessary to meet the requirements of the AMI Program. Accordingly, we have assumed that significant costs for CIS modifications would have also occurred under the base case over 2008-28. We have added the total proposed cost for CIS to the base case, as well as the proportional IT hardware capex associated with CIS that is proposed for 2012-15.

In summary, accumulation meter cost categories included in the base case were:

- Metering capex including maintenance capex
- IT capex (MDM and CIS and associated IT hardware)
- Meter reading opex
- Meter data management opex
- Meter maintenance opex
- Customer service opex.

Metering capital costs over 2008-28 were assumed to continue in line with historical costs, growing with customer number growth (we have assumed 1.6% per annum growth rate, which is in line with that forecast by the distributors). Similarly, metering operating costs were assumed to grow in line with customer number growth.

Costs for outage management systems capex and opex, although included under the AMI OIC as 'within scope', were not included in the AMI Program cost benefit analysis over 2008-28, and were accordingly also left out of the base case scenario. It is our view that outage management system costs are not related to the AMI Program (although may be recoverable under the AMI OIC).

4.3.4 Benefits

Metering benefits assumed under the base case were assumed to be zero, as the benefit analysis of the AMI Program accounts for only incremental benefits delivered by AMI.

While we acknowledge that some of the AMI functionalities driving benefits could be delivered via alternative technologies (for example, direct load control of customer appliances can be delivered without the need for an

AMI meter²³), the base case assumes a continuation of accumulation metering without making assumptions about the uptake of additional technologies.

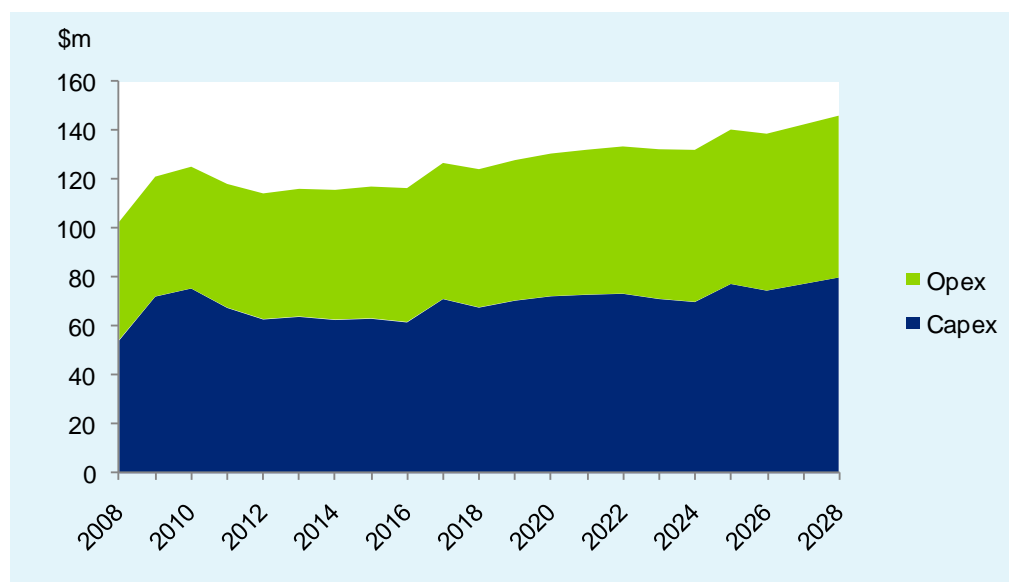
4.3.5 Conclusion

Table 4.1 summarises the base case costs and benefits against which the AMI Program costs are compared.

Table 4.1: Base case costs and benefits

Base case		Total over 2008-28 (million, \$2011)	NPV (at 2008, million, \$2011)
Costs	Capex	1 456	625
	Opex	1 201	592
	Total	2 657	1 218
Benefits	Total	0	0

Figure 4.3: Base case costs, 2008-28



²³ It is noted that the benefits we have attributed to direct load control do not relate to the control of current controlled load appliances, such as electric hot water systems. Our estimate of direct load control benefits assumes the control of air conditioning load.

4.4 AMI Program costs over 2008-2028

In forecasting the total AMI Program costs over 2008-28, we have drawn heavily on the distributors' confidential submissions and budget templates for the AMI budget period 2012-15 (which included actual and forecast cost data over 2009-11).

The budget templates differed among distributors, with certain categories incorporating different costs, and the categorisation of program management varying between capex and opex. In order to carry out the analysis and apply assumptions regarding costs for 2016-28, it was necessary to bring all the costs to a comparable basis.

Due to the structure of the AMI cost recovery framework (separate AMI budget periods), this section describes our cost analysis in three parts: 2008, 2009-15, and 2016-28.

4.4.1 2008 AMI Program costs

Our analysis of the AMI Program lifecycle costs commences in 2008, when distributors were continuing to install accumulation meters for new and replacement sites, purchasing and installing manually read interval meters under the ESC's IMRO decision, as well undertaking planning and investment in IT for the AMI Program. We have included all of these costs in our AMI Program costs, noting that the accumulation metering costs and associated IT expenditure is also included in the base case, and will accordingly be netted out in order to calculate the incremental AMI Program costs.

We have relied on the distributors' charges templates submitted to the AER in February 2011 in order to calculate 2008 AMI Program costs. Costs included in our 2008 AMI Program costs include:

- Net costs (or revenue) associated with providing metering services
- Expenditure on interval meter trials
- Expenditure on installing, commissioning and maintaining telecommunications and IT systems to support AMI
- Relevant project management expenditure
- Relevant interest rate and exchange rate hedging costs.²⁴

4.2.2 2009-15 AMI Program costs

In calculating the costs of the AMI Program over 2009-15, we have generally relied on the distributors' AMI Budget Templates submitted to the AER as part of their Budget Applications on 28 February 2011. The Budget Templates contain detail on the distributors actual (2009), forecast (2010-11) and proposed (2012-15) costs for the AMI Program. We consider that the templates provide a good basis for calculating the total costs of the AMI Program, however in our analysis we have made the following adjustments to the template data:

- Outage management system costs were removed,²⁵ as it is our view that these costs are not related to metering (although may be recovered under the AMI OIC)

²⁴ Detail on the charges template costs was taken from AER, *Draft determination: Victorian advanced metering infrastructure review 2009—AMI budget and charges applications*, July 2009, p. 107.

²⁵ It is noted that AMI benefits associated with improved outage management discussed below would not be facilitated by the proposed expenditure on outage management system. Improved outage management is driven by the communications infrastructure and its ability to communicate with customer meters.

- SP AusNet's metering capex for 2012-15 was reduced to account for the AER's final determination on SP AusNet's Revised Budget Application for 2009-11, as amended in the AER's corrigendum on 30 May 2011. The impact of this decision was a 12% reduction on SP AusNet's proposed metering capex over 2012-15²⁶
- Proposed program management costs for 2014 were reduced to 25% of that proposed, and removed altogether for 2015. The AMI rollout will be completed in 2013, and while there is likely to be some management cost in completing the transition to BAU over 2014, the full proposed costs are unlikely to be necessary. It is our view that these costs are unlikely to be approved by the AER, and therefore, unlikely to be incurred by customers. (This affects all distributors)
- One distributor's (SP AusNet) proposed program management costs for 2012-13 were significantly higher than all other distributors' equivalent proposed costs, and in fact, around 40% higher than the next highest proposal. We have assumed that these costs are unlikely to be approved by the AER, and have reduced that distributor's program management costs to equal the next highest distributor (Powercor).

4.4.2.1 Reasons for not applying further efficiency adjustments to 2012-15 proposed costs

While we have provided some advice on the efficiency of the distributors' proposed opex for 2012-15 based on international benchmark costs (in section 4.4.6 below), Deloitte has not applied any adjustments to the distributors' proposed 2012-15 AMI costs to account for potential AER rejection of certain costs, with the exception of project management costs, as discussed above.

Our objective in carrying out the cost benefit analysis of the AMI Program, was to advise the DTF on the 'likely costs to be incurred by customers' due to the AMI Program. Our reasons for not adjusting the distributor proposed costs over 2012-15 are due to our views on the effectiveness of the AMI OIC in allowing efficient costs to be passed through to customers. We note that these views are also expressed within the AER's submission to the DTF's Issues Paper.

The current AMI OIC provides a cost pass through mechanism, which provides limited scope for the AER to reject proposed costs.²⁷ The AMI OIC provides that proposed costs are deemed approved, unless the AER can establish that costs are outside scope or not prudent, placing the onus of proof on the AER. This creates a significant information asymmetry.

The classification of costs as 'contract' or 'non contract' affects the tests that the AER can apply to expenditure:

- For tendered, contracted costs, it is our view that the AER has limited scope to reject costs. It is noted that the majority of the distributors' proposed contract costs are under framework agreements with suppliers, which were executed in 2009. The AER's Final Decision on the AMI Budgets for 2009-11 approved the general contracting approach and procurement policies and procedures being conducted by the distributors as it made

²⁶ On 28 February 2011, SP AusNet applied to the AER to have its Approved AMI Budget for 2009-11 increased to account for increases in its meter and communications equipment supply costs, among other changes to its program costs. The total change sought by SP AusNet to its 2009-11 budget was \$12.2 million (\$2008). The AER rejected part of SP AusNet's proposed increases relating to metering capex, which resulted in a net decrease to SP AusNet's previous metering capex budget of \$13.5 million (\$2008). It is our view that this decision will not affect the total costs of the AMI Program to customers, given distributors are able to automatically recover up to 120% of the Approved Budget. However, given SP AusNet's 2012-15 AMI budget templates assumed that the AER would approve the proposed increases in costs over 2009-11, in order to incorporate the AER's decision into our analysis, we reduced the proposed metering capex from 2012 by 12%, assuming that the AER will maintain its decision that SP AusNet's proposed metering capex did not meet the relevant tests in the OIC.

²⁷ The AER's submission to the DTF's Issues Paper states its view that the tests in the OIC are less stringent than the National Electricity Rules, with distributors facing a lower hurdle for the recovery of expenditure.

its decision.²⁸ Many of the contract documents provided as part of the distributors' 2012-15 proposals are supported by probity audit documents, to which the AER must have regard. We acknowledge the AER's recent final decision on SP AusNet's Revised Budget Application for 2009-11, which rejected a proportion of retrospective cost increases stemming from signed contracts. Notwithstanding this AER decision (of which the circumstances were unique to SP AusNet), it is unlikely that the AER will establish that the distributors' 2012-15 contract costs were not let in accordance with competitive tendering processes

- For non-contract costs, proposed budgets are approved unless the AER can establish that there has been a substantial departure from the commercial standard that a reasonable business would exercise in the circumstances. Noting again the AER's recent decision on SP AusNet's Revised Budget Application for 2009-11 and putting SP AusNet's unique situation aside, gaining the information required to establish the commercial standard for metering and smart meter related IT and operating costs at the time the distributors committed to the expenditure, and then determining what a substantial departure from this would constitute, is difficult for the AER to do.

The AER's final determination on the distributors' 2009-11 AMI Budgets made only minor reductions to the distributors' proposed costs. The overall adjustment to proposed costs was a reduction of 6% (with approximately one third of this reduction then being re-instated following a successful appeal by two distributors to the Australian Competition Tribunal, meaning in effect 96% of proposed costs were approved).

4.4.3 2016-28 AMI Program costs

This section details our source data and assumptions for the on-going costs of the AMI Program from 2016 to 2028.

4.4.3.1 Recurrent capital costs

Metering and communications capex

Refresh timing

The AMI OIC specifies that metering capex (including meter supply, installation and capitalised program management costs) is depreciated over 15 years, while communications and IT capex is depreciated over seven years.²⁹ Some of the Victorian distributors have indicated they have obtained warranties on their AMI meters for up to 15 years, however they also indicated that this length was difficult to negotiate with suppliers.

Given there is limited real experience to draw from, we considered it reasonable to assume that the meters will be replaced 15 full years after they were installed in the mass rollout. Accordingly, we have assumed that AMI meter capex refresh commences in 2025, in the same profile as carried out over 2009-13. While it could be assumed that the distributors will extend or alter the rollout profile in the second cycle, for the purposes of our analysis we have not assumed that this would have an impact on the total costs of the AMI Program. Sensitivity analysis on the impact of assuming meter replacement after 20 years is outlined in section 4.9 below.

²⁸ AER, Final Decision – note where the AER approved the contracting approach and procurement policies etc. Note also the AER's decision on SPA.

²⁹ AMI OIC clause 4(g).

Despite the shorter seven year depreciation schedule in the AMI OIC for communications equipment, we have assumed that related capex will recur in the 15th year after the initial rollout (or 14 full years later). This reflects our view on the economic life of communications equipment, and the fact that we consider it likely that the distributors will coincide their communications refresh with the meter refresh, commencing one year earlier than meters, in 2024.

Refresh costs

The distributors have generally contracted for their AMI meter supplies six months in advance, and have forecast their proposed meter capex costs based on unit rates being incurred in 2009-10. Previous analysis of the AMI Program costs carried out by EMCa assumed that the market cost of metering equipment will decline over time, similar to other electronic devices. EMCa assumed a real cost decline of 1% per annum.³⁰

Taking into account the materials and manufacturing process of the individual meters (meter, Home Area Network, disconnect/re-closers, Communications card), we expect that the average contracted cost of smart meters could reduce in the order of 25% by 2028. It is noted that this price is sensitive to exchange rates, as well as commodity prices (copper, aluminium and steel).

Accordingly, we have assumed that by 2016, the market for AMI meters will have matured, and that the distributors will be able to obtain more competitive prices for their AMI meters installed for new customers and meter failures. Our assumption is that there will be cumulative efficiencies in metering supply costs of 1.5% per annum from 2016.

We have assumed the same rates of growth and meter failure as that assumed by EMCa, however, given the unit costs of meter supply and installation assumed in 2016-28 are higher than that assumed by EMCa, the overall impact of our analysis is a higher cost. We note that in order to account for the fact that two element meters will not be installed for new customers from 2015 onwards (as no new customers are put on dedicated circuit tariffs – these tariffs are closed), we have assumed a lower cost per meter than that proposed by the distributors, adjusted for the proportion of two element meter customers receiving a two element AMI meter over 2009-13. We note that this does not affect JEN, which has indicated that it will not install two element AMI meters as part of its AMI rollout.

In calculating the total NPV costs of the AMI Program, (as with all capex in our analysis) we have factored in the terminal value of the capital asset. An asset's terminal value is the value of its remaining economic life. Terminal value is calculated separately, then netted off the total costs of the AMI Program. This means that, in effect, the cost of replacing assets towards the end of the period is lowered.

IT capex

Our assumptions regarding recurring IT capex costs vary according to the IT programs, as per the following:

- Outage Management Systems – We consider that these systems are not strictly related to metering, and therefore have excluded associated IT capex costs in the distributors' budget templates

³⁰ EMCa, DPI AMI cost assessment, Appendix A: Cost analysis, p. A-11.

- Asset Management, Meter Data Management Systems – we have assumed capex will recur after seven years, at the same cost as proposed for the initial rollout. This is consistent with the depreciation asset life for IT capex in the AMI OIC
- Field Scheduling and Mobility (also Field Implementation capex) – Given these systems are principally related to the management of the AMI rollout installations, we have assumed that this capex will recur at the same time as the AMI meters, being 15 years after the initial rollout costs, at the same costs as in 2009-15
- Connection Point Management – CitiPower’s and Powercor’s approved IT capex costs for Connection Point Management over 2009-11 are significantly above the costs approved/proposed for JEN, UED and SP AusNet (2 times higher for CitiPower, 4 times for Powercor). While we consider that the 2009-15 costs reflect the likely costs that will be incurred by customers, we have adjusted CitiPower’s and Powercor’s refresh costs to make them equivalent to those of the other distributors. We have assumed this IT system will be refreshed at the same time as the meters, commencing in 2024
- Network Management Systems (NMS) – This capex is assumed to refresh in line with metering, commencing one year prior, in 2024. Noting that SP AusNet’s proposed NMS IT capex over 2012-15 is approximately 50% higher than that proposed by the other distributors, we have assumed that it will refresh at 50% of the costs proposed for 2012-15. All other distributors’ NMS systems are assumed to refresh at the 2009-15 costs
- Performance and Regulatory Reporting and Revenue Management Systems, Geospatial Information Systems, Logistics Management Systems, Other Systems Integration – These costs are assumed to be related to one-off, minor system enhancements incurred due to the AMI rollout, and accordingly we have not assumed any recurring costs
- IT Infrastructure (Hardware, Business to Business and Business to Market) – IT infrastructure costs are related to each of the IT systems discussed above. We have assumed that costs will recur after seven years at the same rate as over 2009-15.

4.4.3.2 Recurrent program management costs

There are some differences in the categorisation of program management costs among the distributors, with one distributor electing to expense all program management for 2009-15. For the purposes of our analysis, we have treated all program management expenditure (including IT program management) as capex by assuming that it will recur in the meter refresh cycle from 2024. This is based on our view that in replacing the AMI meters after their useful life, given the short profile of the replacement program, there will again be some significant program management costs to plan, organise and manage the replacement of, by 2024, approximately 3.2 million meters. We have assumed that given this will be the second time the mass rollout is conducted, program management costs will be incurred at two thirds of the actual/proposed program management costs over 2009-13.

Business integration capital costs (in some cases categorised as program management) were assumed to be one-off costs that will not recur once the mass rollout is complete.

4.4.3.3 Ongoing operating costs

The distributors have indicated in discussions that their proposed operating costs for 2014 and 2015 are likely to be representative of the on-going AMI operating costs. As is discussed in more detail below in section 4.8.2.2, our analysis indicates that the distributors’ proposed opex for 2014-15 is significantly higher than international benchmarks of ongoing costs. We consider that the proposed opex for 2014 and 2015 likely reflects the costs of transitioning from the mass rollout scenario to a steady state of operations. While we consider that the proposed

operating costs for 2014-15 are likely to be incurred by customers, we have assumed that from 2016, international benchmark AMI operating costs will be incurred by customers.

We have conducted a review of typical operating costs for established smart metering systems internationally. Based on the actual operating costs of more than 40 utilities across the US, Europe and Asia, we consider that the efficient cost of operating an AMI or similar system is \$2 per customer per month (US \$2011).³¹

This benchmark suggests that the Victorian distributors' proposed opex for 2015 is approximately 21% overstated. Assuming that only efficient on-going costs are passed through to customers from 2016 (which is discussed further below), we have applied an aggregate 21% efficiency adjustment to proposed 2015 opex costs to generate annual costs from 2016. This efficiency adjustment recurs annually, and decreases as customer numbers increase. Opex categories to which this on-going efficiency is applied include:

- IT (all systems and hardware/infrastructure)
- Metering (meter data services, meter maintenance)
- Communications
- Customer service.

In addition to this aggregate efficiency benchmark adjustment, we have made the following assumptions regarding the on-going operating costs of the AMI Program over 2016-28:

- IT opex – Where a distributor has proposed IT systems opex in 2014-15, our general assumption is that these costs will recur annually at the same rate as in 2015 (subject to our efficiency adjustment). Exceptions to this are noted:
 - Outage Management System opex is excluded, as discussed above
 - On-going Network Management and Meter Data Management system opex is assumed to be equal to 2016 opex, increasing in line with customer number growth
- Other opex:
 - Annual ongoing Meter Data Management and Communications opex is assumed to be equal to 2015 proposed costs
 - Annual ongoing Meter maintenance and customer service opex is assumed to be equal to 2015 proposed, increasing with customer numbers.

³¹

This benchmark was taken from a confidential data base. Operating cost data included in the benchmark is from the following utilities: Alabama Power - [Southern Company]; Bangor Hydro – Maine; Black Hills Corporation - in the Dakotas; Central Maine Power Company; Centerpoint; Detroit Edison – Michigan; Edison International - Southern California Edison (SCE); Florida Power & Light Company; Georgia Power - [Southern Company]; Gulf Power Company - [Southern Company]; IDACORP; Indianapolis Power & Light Company - [IPALCO]; Kansas City Power & Light Company; Minnesota Power; Mississippi Power Company - [Southern Company]; NV Energy; Pacific Gas & Electric; PP&L, Inc; San Diego Gas & Electric; SCANA Corporation - SCE&G; Tucson Electric Power; Wisconsin Public Service Corporation; Southern California Edison; Alliant; Pacificorp; Coops and Munis; JEA; Plymouth Utilities; United Electric Coops; City of Camrosa; City of Anaheim; Lee County Coop; City of Ocean Springs; EdF; Vattenfall; ENEL; Birka; Nuon; ESB; All South Korean Utilities.

4.4.4 Conclusion – Total AMI Program costs 2008-28

Our estimated total AMI Program costs are outlined in Table 4.2. These costs reflect the sum total costs of the AMI Program, including some accumulation metering costs incurred by distributors during the rollout, as provided for in the AMI OIC.

Table 4.2 AMI Program total costs

AMI Program total costs	Total over 2008-28 (million, \$2011)	NPV (at 2008, million, \$2011)
Capex	3 567	1 727
Opex	1 765	924
Total	5 332	2 651

Note: Costs presented here are prior to netting off the base case costs or making adjustments to bring costs into a comparable basis to EMCA's analysis.

4.4.5 Other costs required to achieve benefits

As noted above, our analysis is focused on the costs and benefits of the AMI Program to Victorian electricity customers, as opposed to taxpayers. This section discusses additional costs that we assume need to be incurred by customers and Government in order to achieve the benefits we have assumed below.

4.4.5.1 Customer engagement program

Our discussions with stakeholders revealed a consistent view across the industry that to date, there has been insufficient customer engagement in relation to the AMI Program.

At present, there is growing reluctance in the Victorian community to embrace the AMI Program. This has the potential to significantly reduce the benefits and increase the costs of the AMI Program if community engagement is not undertaken immediately. International experience suggests that small groups with interests in preventing the installation of smart meters can draw on this community uncertainty, particularly in regards to perceived concerns regarding the safety of smart meters and radio frequency (RF) radiation.³² In Victoria, in addition to the concerns regarding the safety of smart meters, other concerns with the AMI Program are affecting its overall public perception and acceptance.

There is a view among non-Government stakeholders that it is solely the Victorian Government's role to manage and facilitate community engagement for the AMI Program. We understand that this view has stemmed from various stakeholder meetings over 2008-11. This view is limiting and in most cases preventing any action on the behalf of retailers, distributors or other stakeholders with regards to community engagement.

International experience suggests that consistent, targeted education on the objectives and benefits of smart metering is the key to the successful realisation of benefits. The actions of Victorian customers are critical to achieving the benefits of AMI, in particular benefits that rely on voluntary take up of time of use tariffs, critical peak

³² The Victorian Government has recently commissioned a field study of the RF and electromagnetic emissions from smart meters, which is currently on-going. In our analysis, we have assumed that this study will not identify any significant detrimental health impacts stemming from the AMI meters.

pricing or incentives, direct load control and use of in-home displays. In addition, customer acceptance of the Program is fundamental to ensuring that costs of rolling out and maintaining the infrastructure are efficient (see discussion on risks of cost increases below, in section 4.8). Box 3 describes the program carried out by Canadian distributor HydroOne in relation to its smart meter rollout, which is widely viewed as the most successful example of customer education and consultation to date.

Box 3: HydroOne – Customer engagement program

Canadian distributor HydroOne has installed more than 1.2 million smart meters across Ontario (close to 100% of meters are installed), and as at June 2011, had transferred around 900 000 customers to TOU pricing. The Ontario Energy Board (Government) mandated that all HydroOne customers must be transferred to TOU pricing by October 2011,

To date, there has been very limited negative feedback from customers. This positive outcome is largely due to an extensive customer communications process that commenced prior to the rollout and continues today, involving door hangers, newsletters, community meetings and substantial media outreach. Innovative web portals provide customers with information on real time prices, peak demand and weather adjusted consumption data. Transitioning³³ to monthly billing as soon as possible enabled customers to realise the benefits of their new smart meters.

It is our view that a sustained customer engagement program needs to be undertaken immediately to mitigate the risk of further cost increases and to ensure that benefits are able to be realised from 2014 onwards. Our estimates of the benefits to be delivered by AMI are dependent on this customer engagement program.

We have identified three separate issues that need to be targeted through customer engagement: Smart meter safety; general network and energy efficiency and other non-tariff benefits of the AMI Program; and innovative tariffs and demand management benefits of the AMI Program.

1. Smart meter safety

There is some concern in the Victorian community that RF radiation emissions from smart meters could cause health effects. There is also concern about the ability for parties to determine when someone is at home, based on their consumption data transmitted via the AMI network. Other concerns regarding the safety of smart meters have been expressed in recent media. To date, very limited information regarding smart meter safety has been provided to customers.

In our view, the concerns regarding RF radiation from smart meters are most troubling because of the potential ripple effect to the deployment of G4 cellular networks, RF based rural broadband networks and other future RF communications technologies. We note that this is becoming an issue in California, where reports of the impact of smart meters on health and the resulting community concern has spread to concerns regarding mobile phone use.

In our view, if left unaddressed, concerns about smart meter safety could de-stabilise customer acceptance of the AMI Program and place the achievement of any benefits at significant risk. We consider this issue to be one that the Victorian Government must address immediately in any event, whether it decides to continue or amend the

³³

HydroOne website: Smart meters. Available at: <http://www.hydroone.com/MyHome/MyAccount/MyMeter/Pages/SmartMeters.aspx> ; Johnson, JF, *Smart Grid Consumer Engagement: where does the education campaign begin?*, Smart Grid Update, 7 March 2011, available at: <http://analysis.smartgridupdate.com/industry-insight/smart-grid-consumer-engagement-where-does-education-campaign-begin>

AMI Program.³⁴ Our analysis assumes that community engagement on smart meter safety is carried out in every scenario.

2. General network and energy efficiency and other non-tariff related benefits of the AMI Program

General AMI benefits that do not stem from innovative tariffs and peak demand management need to be communicated with the Victorian community. In our view, there is a very limited understanding in the general population on the reasons for installing smart meters and what they are to be used for (and a concern regarding TOU tariffs, which is why separate communication on this issue is important).

Shorter outages, better energy consumption information, and the ability to integrate more renewable resources and electric vehicles into the grid are all benefits of AMI that have not been communicated to Victorian customers. It is important that customers understand the role of smart meters and the related AMI systems in making these and other technology changes possible. While the market take up and rate of change of embedded generation and energy efficiency appliances is in the hands of the consumer, AMI will help direct the efficient use of capital to speed the implementation of these devices in the electricity network, while helping to maintain the reliability of the network during this potential period of change in electricity consumption.

AMI will deliver fewer estimated bills, and fewer unexpectedly or unexplainably high bills, and will also reduce the need for customers to phone in outages. These are all AMI benefits that will have a real impact on customers, and which to date have not been effectively communicated to customers.

Our analysis under each scenario (Continuing the AMI Program and Slowing the Pace) assumes that the Government carries out a customer engagement program to identify the benefits associated with network and energy efficiencies generated by AMI.

3. Innovative tariffs and demand management benefits of the AMI Program

Customer benefits delivered by TOU tariffs, critical peak incentives, or direct load control are the most controversial benefits that can be derived from deployment of smart meters, as they require customers to change their behaviour (or agree to have their energy controlled) in response to price incentives. We consider that community engagement to facilitate an understanding on the issues regarding innovative tariffs and demand management, and to encourage customers to take up innovative tariffs and respond to price incentives, is critical to achieving approximately \$490 million of benefits over the total AMI Program lifecycle (NPV at 2008).³⁵

Our analysis under each scenario (Continuing the AMI Program and Slowing the Pace) assumes that the Government carries out a customer engagement program regarding TOU tariffs, critical peak incentives and direct load control, as part of a general AMI customer engagement program. However, noting the controversy surrounding this category of benefits, we have separately identified the benefits under each scenario that are associated with this customer engagement.

³⁴ It is noted that the Victorian Government has recently commissioned a field study of the RF and electromagnetic emissions from smart meters, which is currently on-going. In our analysis, we have assumed that this study will not identify any significant detrimental health impacts stemming from the AMI meters.

³⁵ This figure reflects the total estimated benefits attributable to innovative tariffs and demand management and energy conservation (driven by IHDs), over 2008-28.

Assumed costs of customer engagement

Our analysis of the AMI Program costs does not include costs to Government or any other party incurred in implementing customer engagement. We consider that, where implemented by Government, community engagement costs are likely to be costs to taxpayers more generally and not Victorian electricity customers, and where implemented by retailers, costs will be absorbed in the competitive market. We have not assumed that distributors have a role in community engagement for the AMI Program, however note that this is possible where distributors elect to offer TOU tariffs or other demand management contracts.

4.4.5.2 In home displays and direct load control devices

In previous analyses, the costs associated with supply and installation of in-home displays and direct load control devices needed to control appliances have been added to the AMI Program costs.

As is discussed in detail below, we have assumed in-home displays and direct load control will be taken up by 1% of customers in 2014, increasing to a maximum of 25% of customers in 2020. Based on international experience, we assume the average cost of an in-home display is \$125, while the assumed cost to purchase and install a direct load control device to an air-conditioner is estimated at \$75 per customer.

Potentially, in-home displays and direct load control could be offered to customers by their retailers as part of a contract. In this case, some of the costs of the devices would presumably be absorbed by competitive retailers and therefore would not be a cost to Victorian electricity customers. However, given there is some potential that customers could independently purchase and install in-home displays, we have assumed that these costs are AMI Program costs, and therefore incurred by customers.

4.4.6 Cost prudence assessment

Part of our brief in developing the cost benefit analysis of the AMI program was to make an assessment of the distributors' 2012-15 AMI budget applications that were submitted to the AER in February 2011. In particular, we were asked to ensure that the 'expenditure is prudent and based on rigorous assumptions and commercial principles'.

We have outlined in our analysis of the AMI Program costs some adjustments made to the distributors' 2012-15 proposed AMI program management costs to account for our view that they are unlikely to pass the prudence test in the AMI OIC and therefore will not be approved by the AER. While we consider the remainder of the 2012-15 proposed costs reflects the 'likely cost to be incurred by customers', there are areas of the distributors' proposed costs that may not be prudent. In estimating the AMI Program costs from 2016-28, we have only included those costs we consider to be the efficient costs of the AMI Program.

Our approach to testing the prudence of the distributors' proposed budget expenditure relied on internal benchmarking of distributor costs against each other, and international benchmarking of broad capex and opex cost categories on a per customer basis.

Drawing on a significant bank of international smart meter rollout experience, we make the following observations about the distributors' proposed budgets for 2012-15, as set out in table 4.3. The table provides the estimated impact that not approving the distributors' proposed costs would have on our estimate of total AMI Program costs over 2012-15.

Table 4.3: Assessment of the prudence of proposed costs over 2012-15

Cost category	Comments	Estimated impact on our total AMI Program costs over 2012-15 (\$,2011)
Program Management	One distributor (SP AusNet) proposed program management costs of over 40% higher than the other distributors in 2012-13. Also, all distributors proposed significant program management costs for 2014 and 2015 (CitiPower and Powercor). It is our view that these costs are unnecessary.	\$0 (these were adjusted within our estimate of the total costs of the AMI Program)
IT capex - Connection Point Management (CPM)	Two distributors (CitiPower and Powercor) proposed CPM costs significantly above the other distributors' costs over 2009-15. However, the majority of the costs were approved for 2009-11 and are therefore sunk. Recommend that further proposed CPM costs for 2012-15 be rejected.	\$4.9 million
IT capex – Network Management System (NMS)	One distributor (SP AusNet) has proposed significantly higher NMS costs than the other distributors over 2009-15. Again, most of this difference was approved over 2009-11. Recommend that further proposed NMS costs for 2012-15 be rejected.	\$3.8 million
Ongoing opex	As discussed in section 4.4.3.3 above, the distributors' metering operating costs for 2015 are approximately 21% higher than international benchmarks.	\$33.2 million

4.5 Incremental costs of AMI Program over 2008-28

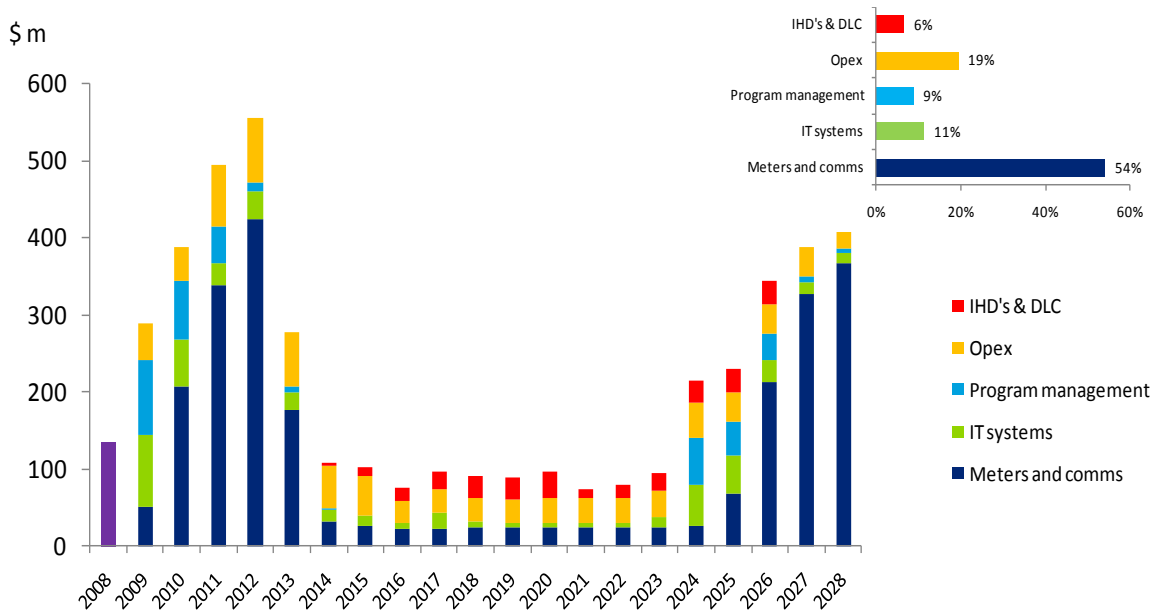
As discussed in section 4.2, subtracting the base case costs from the total AMI Program costs results in the incremental costs attributable to the AMI Program. To this, we added the avoided costs of accumulation metering and meter reading to develop 'total comparable costs', which can be compared with the previous analyses of the AMI Program. Table 4.4 lists the total costs the AMI Program over 2008-28, and Figure 4.4 presents the profile of AMI Program costs over the period.

Table 4.4: AMI Program costs

	Total over 2008-28 (million, \$2011)	NPV (at 2008, million, \$2011)
AMI Program total costs	5 332	2 651
Base case total costs	2 657	1 218
<i>True incremental AMI costs</i>	2 676	1 434
Avoided costs of accumulation metering and meter reading*	1 676	802
Other costs required to achieve benefits (IHDs and direct load control)	292	113
(Comparable) AMI Program costs	4 644	2 349

* As discussed in section 4.2, to maintain consistency with the previous AMI Program cost benefit analyses, we have accounted for the avoided costs of accumulation metering capex and reading as 'avoided cost benefits'. As such, these costs need to be added to incremental AMI Program cost assessment to avoid double counting.

Figure 4.4: Total AMI Program Costs over 2008-28



Note: 2008 costs are total, terminal values (ordinarily subtracted in 2028) have not been subtracted in this graph in order to show total profile of AMI costs

Table 4.5 presents the AMI Program costs by the key cost categories.

Table 4.5: AMI Program costs by cost categories

Cost category	Total cost (\$ m)	(NPV at 2008, m)
Meters and communication	2 440	1 135
IT systems	512	261
Program management	393	250
Opex	874	456
IHD's & DLC	292	113
2008 total costs	134	134
Total	4 644	2 349

Note: 2008 costs are difficult to segment into the various categories. Terminal value has been incorporated in the NPV values

The total AMI Program cost NPV of \$ 2 349 million is split into the following three time periods as follows:

- 52% of the costs are incurred in NPV terms over the period 2008-11 (these costs are largely approved by the AER).

- 32% of costs in NPV terms are projected to be incurred over the period 2012-15.
- 18% of costs in NPV terms are projected to be incurred over the period 2016-2028 (terminal value benefits have been included in this period).

4.6 AMI Program benefits over 2008-28

In forecasting the benefits of the AMI Program, we have reviewed the previous benefit analysis undertaken by Futura and Oakley Greenwood, updated parameters based on current market development and technology maturity and applied relevant international and local benchmarks. We have also ensured that our analysis reflects the current state of play in terms of interaction between the distributors and retailers in delivering AMI services.

As outlined in section 4.4.5 above, we have assumed that a Government-led, targeted community engagement program is undertaken over 2011-13 such that customers are better informed and ready to take up time of use tariffs, critical peak pricing incentives and direct load control from 2014.

The benefits of the AMI Program can be categorised into four broad categories:

1. Avoided costs associated with accumulation meters resulting from the AMI Program
2. Benefits derived from efficiencies in network operations
3. Benefits generated by innovative tariffs and demand management
4. Other smaller benefits (incorporating minor efficiencies in network and retail operations).

Our analysis for each of the benefit categories is presented in the following sections.

4.6.1 Avoided costs resulting from the AMI Program

This category comprises of two key benefits:

- Avoided cost of replacing accumulation meters and time switches
- Avoided cost of manual meter reading.

As noted in the discussion on the base case in section 4.3 above, we have relied on publicly available information on the Victorian distributors' accumulation metering costs over 2001-09 to determine the avoided costs. This included data taken from regulatory decisions made by the ORG in 2001, the ESC in 2006 and the AER's decision on AMI costs over 2009-11 (noting that this latter decision incorporates metering costs over 2006-08). Historical cost data on meter supply capex and meter reading were sourced from these decisions. Both accumulation meter replacement and manual meter reading costs were escalated by the projected growth in meter numbers over 2008-28.

Table 4.6 presents our estimates of the avoided costs resulting from the AMI Program, as compared to the previous analyses.

Table 4.6: Avoided costs resulting from the AMI Program (millions, NPV at 2008)

Benefit	Futura 2010 ³⁶	Oakley Greenwood	Deloitte
Avoided cost of replacing accumulation meters	492	492	649
Avoided cost of replacing time switches	75	75	Incorporated in avoided cost of replacing accumulation meters
Avoided cost of manual meter reading	288	288	154
TOTAL	855	855	802

Note: This report presents Futura’s and Oakley Greenwood’s benefit estimates as per their models, in \$2008. Deloitte’s estimates are based on \$2011 inputs.

We have been unable to verify the calculation underpinning the Futura benefit estimate of avoided costs. Oakley Greenwood accepted Futura’s estimate of avoided costs.

4.6.2 Benefits derived from efficiencies in network operations

This category of benefits relates to the improvements in network management and efficiency that are expected to result from the AMI rollout. In valuing the avoided unserved energy resulting from network efficiencies, we have used the most up to date data available on the value of customer reliability, taken from a recent AEMO study.³⁷ We have also used data on service charges taken from the AER’s Victorian Distribution Determination, released in November 2010. Appendix A contains a list of the assumptions used in calculating AMI benefits.

This category comprises of the following benefits:

- Reduction in unserved energy due to faster detection of outages and restoration times
- Avoided cost of special meter reads, manual disconnections and reconnections (and avoided revenue loss)
- Avoided additional cost of energy from time switch clock errors
- Savings from reduction in non-technical losses (theft)
- Avoided cost of proportion of transformer failures on overload and avoided unserved energy
- Ability to set emergency demand limits to share limited supply at times of network stress or supply shortage.

³⁶ It is noted that the Oakley Greenwood final report refers to Futura estimates of benefits taken from Futura’s December 2009 analysis. Futura updated its assessment in May 2010. When referring to Futura estimates, our report is referring to the May 2010 updated analysis.

³⁷ Oakley Greenwood, Valuing Reliability in the National Electricity Market, March 2011.

4.6.2.1 Reduction in unserved energy due to faster detection of outages and restoration times

An AMI meter has an in-built capability of sending a signal back to a distributor control room to indicate that that it has no electricity supply. Futura and Oakley Greenwood estimated that this functionality alone would result in a 10% improvement in the System Average Interruption Duration Index (SAIDI) of Victorian distributors.

We have considered the specific drivers for this benefit in detail, and have found that the previous benefits analysis significantly overestimated the potential SAIDI improvements delivered by AMI.

Features of the existing Victorian distribution network – high voltage system SCADA

The Victorian electricity distribution network has a high penetration of Supervisory Control and Data Acquisition (SCADA) monitoring. The vast majority of 11kV, 22kV and 66kV high voltage (HV) feeders in the distribution network can be remotely monitored and switched at the circuit breaker (CB) supplying the HV feeders in zone substations. In some cases, segments of HV feeders can also be remotely monitored and switched by use of appropriately enabled and positioned Automatic Circuit Reclosers (ACR) and other switches.

A HV feeder outage can affect thousands of customers. In the event of an HV feeder outage, an alarm in the distributor's control room will indicate which automatic feeder switching element has operated. Since the customers and areas controlled by this switching element are known, the control room has immediate knowledge of the extent of the HV feeder outage. Whilst the cause of the HV feeder outage may not be known, the control room will usually know that it has occurred before any customers ring in to a call centre to report the outage.

Accordingly, an AMI meter sending a signal back to a control room that it has no supply will have little benefit, in terms of reducing outage notification time, for an outage on a HV feeder which is SCADA enabled.

Benefit of smart meters for the low voltage system

SCADA does not generally extend to the monitoring and control of the low voltage (LV) system. An outage occurring on the LV system can affect up to a few hundred customers, depending on the population density of the area it supplies and the size of the distribution transformer supplying those customers. A fault on the LV system will usually result in the operation of an LV fuse. This fuse will need to be manually replaced to restore supply. Moreover, the control room may not know that an LV outage has occurred until customers ring in to the call centre to report an outage.

AMI provides some benefit for LV outages, as it enables the control room to quickly verify if an outage is affecting a single premise or an isolated set of customers. Whilst this benefit would be unlikely to significantly reduce SAIDI results due to the smaller numbers of customers affected in LV outages, it will allow those affected customers to be remotely identified and appropriate schedules developed for the restoration of their supply.

AMI meters will improve the distributors' ability to respond to multiple HV feeder and LV outages resulting from severe storm conditions. Whilst control rooms currently have knowledge, via SCADA, of the HV feeder outages due to the storm conditions, they may not know about embedded LV faults. The HV feeder faults will be repaired and supply restored, however the LV embedded faults can remain. There have been instances of single customers being off supply for a number of days as a result of this scenario.

There is also potential benefit in reduced restoration times in semi-rural and rural areas, where repair crew notification time and travelling time to a fault are significant components of overall outage duration time.

In addition, this particular AMI functionality provides additional information that a control room and its associated Outage Management System can use to analyse and prioritise outage restoration. Is it likely that given this

additional information, innovative strategies will be developed over time to improve outage times. However, this additional benefit is difficult to quantify.

Given the distribution network’s current functionality, the following percentage SAIDI improvements rates have been applied in our estimate of the benefits of faster outage detection and restoration of supply:

- A – LV network monitoring improvement – 2%
- B – Semi-rural area notification time improvement – 1%
- C – Rural area notification time improvement – 1%
- D – Outage Management innovation – 1%

This results in the following percentage SAIDI improvements rates being applied to the distribution businesses:

- CtitPower (A+D) = 3%
- JEN (A+B+D) = 4%
- UED (A+B+D) = 4%
- Powercor (A+B+C+D) = 5%
- SP AusNet (A+B+C+D) = 5%

Calculating the benefit

Using our assumed SAIDI improvements for each distributor, this benefit is calculated according to the following variables:

- Penetration of AMI meters - as forecast by the distributors. Our assumption is that the associated benefits will start accruing once 80% of the AMI meters are installed and communicating.
- Value of unserved energy – taken from the recent AEMO update of the Value of Customer Reliability (VCR):³⁸
 - Residential VCR \$20 395/MWh – 80%
 - Commercial VCR \$90 769/MWh – 20%.

Table 4.7 compares our estimated benefit resulting from faster detection of outages and restoration times to that calculated by Futura and Oakley Greenwood.

Table 4.7: Reduction in unserved energy due to faster detection of outages and restoration times (millions, NPV at 2008)

Futura 2010	Oakley Greenwood	Deloitte
238	375	66

³⁸ Oakley Greenwood, Valuing Reliability in the National Electricity Market, March 2011.

4.6.2.2 Avoided cost of special reads, avoided cost of manual disconnections and reconnections (and avoided revenue loss)

AMI offers the ability to provide some common customer services via remote communication, negating the need to send a linesman or field officer to a customer's address. Services that AMI enables remotely include special meter reads, de-energisation and re-energisation. Approximately 22% of Victorian electricity customers request these services annually, which are generally required when a customer moves house. Special reads are also required when a customer wishes to re-check their meter read, change retailers or when meters are exchanged.

In the previous benefit analyses, given it is typical for a distributor to charge a combined special read and de-energisation charge when a customer moves out (assumed by Futura and Oakley Greenwood to be \$30), the value of the avoided charge was multiplied by the number of customers requesting the service each year. For re-energisations, Futura and Oakley Greenwood calculated the avoided manual charge, as well as the value of unserved energy for customers who do not have their premises re-energised on the same day as making the request. Futura assumed that these customers were off supply for 8 hours on average, while Oakley Greenwood revised this to 16 hours. There were also differences in Futura's and Oakley Greenwood's assumed VCR.

In analysing these remote services benefits, we have applied a similar methodology to the calculation of avoided customer charges, however we have updated the assumed customer charges to account for the approved manual charges within AER's Victorian Distribution Determination for 2011-15. We have also calculated the avoided manual special read charge as an additional avoided charge to manual de-energisation, based on our understanding of how distributors charge customers for move-outs.

We have taken a different approach to valuing the avoided loss of supply for customers receiving non-same day re-energisations. Given the distributors have specific regulated alternative control service charges for after hours re-energisations, we consider that the maximum value to customers of being able to be re-energised remotely instead of waiting for a non-same day charge is actually equal to the distributors' manual after hours re-energisation charges. In 2011, the average manual after hours de-energisation charges of the Victorian distributors is calculated at \$75. We have accepted Futura and Oakley Greenwood's assumption that 190 000 non-same day re-energisations were performed in 2008, increasing with customer number growth over 2009-28.

Remote services are able to be performed as the AMI meters are rolled out and connected to the communications network, and should be able to be performed for the approximately 7% of customers who have an AMI meter installed that is communicating remotely (as at 31 May 2011). The AER made a Remote Service decision on interim charges for remote provision of these services in February 2011, in anticipation of the distributors being ready to provide remote services. However, our discussions with distributors and retailers have revealed that these remote services are not currently being provided due to a disagreement between retailers and distributors regarding customer liability. It is our assumption that this disagreement is resolved and remote services are able to be provided from the beginning of 2012.

Table 4.8 compares the NPV of our calculated benefits to that calculated by Futura and Oakley Greenwood.

Table 4.8: Remote special reads, de-energisations and re-energisations (millions, NPV at 2008)

Benefit	Futura 2010	Oakley Greenwood	Deloitte
Remote special reads and de-energisations	147	147	149
Remote re-energisations	145	364	209
Total	292	511	358

4.6.2.3 Avoided additional cost of energy and peak demand from time switch clock errors

Time switches are used to control specific customer loads (typically electric storage hot water systems and slab heating) such that they come on at off-peak times. In replacing accumulation meters as part of the AMI rollout, distributors will also replace time switches for controlled load customers, as the AMI meters contain in-built time switches. Given around 5% of accumulation meter time switches do not correctly control load (due to errors and tampering), and assuming that the AMI meter time switches will be more accurate and less prone to tampering, there is some benefit associated with less peak electricity consumed. We note that the AMI meter time switches are in-built electronic timers, automatically corrected every four hours based on the master GPS clock of the AMI system.

While Futura estimated only the avoided cost of energy associated with correcting the time switch errors, Oakley Greenwood added the additional benefit of lower peak demand on the networks and generators. Oakley Greenwood assumed a value of avoided peak demand of \$200 000/MW/year.

We have agreed with the general approach taken to estimating this benefit, however have amended the calculation as follows:

- Controlled load tariffs (and time switches) have not been available for new customers for some time, due to the phase out of storage hot water heating. As old water heaters are replaced, we have estimated that there is an annual decline in the time switch population of 1%
- In valuing the reduction in peak energy used, we have updated the average Victorian pool prices used by Oakley Greenwood to reflect more recent price data
- The distributors' 2012-15 AMI proposals incorporate information on the number of two element meter customers in each distributor's territory. Based on this information, we have increased the assumed number of time switches from 549 000 to 665 081.

Some consideration was given to Oakley Greenwood's assumed value of avoided peak demand. Oakley Greenwood's estimate of \$200 000/MW/year reflects the avoided costs of investment in peaking generation (Open Cycle Gas Turbine, OCGT) and network augmentation. While this concept has merit, the decisions around investment deferral will depend upon current supply and demand balance, projected growth and capacity requirements. To undertake a more precise assessment of the value of peak demand reduction would require detailed market modelling, which is beyond the scope of this project. Accordingly, we have accepted the simpler approach adopted by Oakley Greenwood, which values the deferral benefit by assuming that every megawatt of peak demand reduction will defer a megawatt of peaking capacity (both generation and network). Based on the current costs of OCGT and network augmentation, we consider that Oakley Greenwood's estimate of \$200 000/MW/year is acceptable.

Table 4.9 compares the NPV of our calculated benefits to that calculated by Futura and Oakley Greenwood.

Table 4.9: Avoided additional cost of energy and peak demand from time switch clock errors (millions, NPV at 2008)

Futura 2010	Oakley Greenwood	Deloitte
51	42	26

4.6.2.4 Savings from reduction in non-technical losses (theft)

Internationally, non-technical losses (or theft of electricity) have a significant impact on distributor and retailer revenue. Many sites of electricity theft are found to be involved in other criminal activities. It is more difficult to steal electricity where a smart meter is installed.

Neither Futura nor Oakley Greenwood calculated any benefits associated with theft rectification due to the AMI rollout. The Victorian distributors have indicated in discussions that electricity theft is not a material issue in Victoria. However, given international experience, we consider that this is likely to be an under-realised issue in Victoria, and have accordingly calculated the benefit associated with the AMI rollout.

Following discussions with the distributors, we have conservatively assumed that theft in Victoria is equal to 0.5% of energy sales. We have also assumed that the uncovering of this theft will result in a 50% reduction in energy use for the theft sites (assuming that thieves will choose to continue to use electricity, however will significantly reduce their consumption once being charged for it). To value this change, we have used actual Victorian pool price data and forecasts based on a recent ACIL Tasman report.³⁹ This is consistent with our estimation of other benefits.

Table 4.10 compares the NPV of our calculated benefits to that calculated by Futura and Oakley Greenwood.

Table 4.10: Savings from reduction in non-technical losses (theft) (millions, NPV at 2008)

Futura 2010	Oakley Greenwood	Deloitte
0	0	27

4.6.2.5 Avoided cost of proportion of transformer failures on overload and avoided unserved energy

Distribution transformers periodically fail when overloaded, sometimes resulting in outages as well as the costs of repairing equipment. AMI enables better monitoring of the loads on transformers, as demand at each point in the network is known to the distributor.

Futura and Oakley Greenwood assumed that as customer loads on a particular transformer approach its maximum capacity, distributors will be able to enact the supply capacity limiting functions of AMI to prevent the overload occurring.

³⁹ ACIL Tasman, *Energy market modelling – expansion of the ESI scheme*, 21 February 2011. Report prepared for The Department of Primary Industries, Victoria.

As is discussed in detail below in section 4.6.2.6, we consider that the ability of distributors to use supply capacity limiting to control loads at times of network stress is limited. However, we consider that there is benefit in the distributor being able to better monitor its equipment and therefore reduce the need to replace some transformers by proactively repairing them. Given fewer transformers will fail, we also consider there is some value in the associated avoided unserved energy.

We have accepted Futura’s and Oakley Greenwood’s estimate of the average cost of a transformer (\$50 000). Consistent with our approach in calculating other benefits, we have used the most recent AEMO data on VCR in estimating the value of avoided unserved energy.

Table 4.11 compares the NPV of our calculated benefits to that calculated by Futura and Oakley Greenwood.

Table 4.11: Avoided cost of proportion of transformer failures on overload and avoided unserved energy (millions, NPV at 2008)

Futura 2010	Oakley Greenwood	Deloitte
20	28	29

4.6.2.6 Ability to set emergency demand limits to share limited supply at times of network stress or supply shortage

We have identified two plausible ways that a distributor could implement demand limits during emergencies or periods of network constraints using the AMI system. The method of implementing demand limits depends on whether there is a voluntary load control contract with the customer, or whether mandatory demand limits are applied to all customers with AMI meters.

Voluntary demand limit contracts

One of the functionalities of an AMI meter is that it has the capability, in conjunction with a Home Area Network, to turn off various customer load elements, such as hot water systems, air conditioners, pool pumps, etc. As a result, in the event of emergency generation or network constraints, this functionality could be used to reduce individual customer loads to alleviate the need to shed load.

In order to reduce customer loads in this manner, the customer take-up of direct load control would have to be significant, and each customer with direct load control would need to have a number of controlled load elements (appliances). In order to achieve 1 MW of load reduction at times of network stress, 1kW of load reduction from 1000 customers is needed.

The nature of the system constraint requiring load reduction will affect any possible benefit. The quantum of load reduction needed, the locality of the area constrained and the short timeframe to achieve the reduction need to be aligned to available demand reduction. Widespread load reductions of hundreds of MW (which is typically what occurs with load shedding) would be difficult, and smaller more localised reductions may also be difficult if the load reduction required is greater than the localised controllable load.

We acknowledge that benefits could be realised for smaller and more widespread load reduction scenarios using voluntary direct load control, however, we believe that this benefit has already been captured in our estimate of the benefits of direct load control, discussed below.

Mandatory household demand limits

During periods of constrained supply or in emergency situations, a demand limit can be determined directly in each household's AMI meter, without requiring direct load control of appliances. This demand limit would be set by the market operator (AEMO), and could vary between events.⁴⁰ Should the determined demand limit be exceeded by the household's consumption, the disconnect in the meter would open for a minimum 'safe period' (typically 5 minutes), completely turning off the flow of electricity. Once that 'safe period' has expired, provided the household demand has reduced to the determined demand limit or below, the house would be re-connected and electricity would again flow. The customer would need to be informed that during the 'safe period' of outage, they need to decide what appliances/loads to switch off in order to prevent being disconnected again.

In order for this AMI facility to be implemented and provide benefit, significant regulatory changes and the establishment of interface messages between AEMO and the distributors are needed.

We have calculated this benefit by reviewing load shedding incidents in Victoria over 2005-10 and making some assumptions regarding:

- the likely available demand reduction from domestic Victorian customers at times of emergency and network constraint, being 1008 MWh per annum.
- customer value of lost load at times of emergency and network constraints, which we have assumed is equal to domestic customer VCR, discounted by 25% to account for the non-linearity of VCR.

We consider that this benefit will not be realised until the AMI rollout is completed in 2013.

Table 4.12 compares the NPV of our calculated benefits to that calculated by Futura and Oakley Greenwood.

Table 4.12: Ability to set emergency demand limits to share limited supply at times of network stress or supply shortage (millions, NPV at 2008)

Futura 2010	Oakley Greenwood	Deloitte
428	0	82

4.6.3 Benefits generated from innovative tariffs and demand management

This category of benefits is highly dependent on customer responses to AMI and associated changes in tariffs and other incentives. In our view, these benefits are the most difficult to estimate, and given their higher potential variability than the avoided cost or network efficiency benefits, pose the greatest risk to the success of the AMI Program.

It is noted that the impact of customer behavioural change at times of peak on the ability to defer network and generation investment is uncertain. Customer demand management is significantly less reliable than supply side responses to network and market constraints. Accordingly, generation and network planning cannot fully rely on demand side response in planning new investment. However, over time, as information on customer behavioural responses improves, the reliability of demand management will improve. Furthermore, demand response provides

⁴⁰ Note that the retailer does not have a role in determining emergency demand limits, and that this function is not related to setting demand limits for credit control purposes.

trading benefits for retailers exposed to peak pool prices, which will be passed through to customers via the competitive retail market. In our analysis, we have assumed that customer demand response results in an immediate deferral of investment. In practice, the impact may be lagged, due to the 'lumpy' nature of network and generation investments. However, given our task is to estimate benefits over a lengthy (twenty year) period, we consider it is reasonable to apply the impact of demand response on investment as it occurs.

Our estimates of the assumed customer take up rates and likely customer behaviour in response to tariffs and other incentives are based on both international and Australian studies and trials. Our assumptions in estimating the benefits of the AMI Program over 2008-28 are outlined in Appendix A.⁴¹

It is important to note that, ignoring the fact that some individual customers may be involved in more than one incentive tariff or demand management project, our assumptions regarding time of use (TOU) tariffs, critical peak incentives, in home displays (IHDs) and direct load control collectively imply that 75% of Victorian residential customers will change their consumption behaviour in response to incentives delivered by the AMI rollout. This is implying a significant change among Victorian electricity customers, and highlights the need for customer engagement and appropriate market offers to enable this to be achieved. Any further Government programs to encourage customer participation (such as the deployment of IHDs) would improve this anticipated effect.

This category comprises the following benefits:

- Energy conservation from TOU tariffs
- Avoided network and generation augmentation due to peak demand response to TOU tariffs
- Avoided network and generation augmentation resulting from critical peak pricing incentives
- Energy conservation from IHDs and enhanced billing
- Reduced peak demand due to direct load control of air conditioners.

4.6.3.1 Energy conservation from time of use (TOU) tariffs

One of the principal features of AMI is the ability to record individual customer energy usage in half hour intervals. Interval data enables retail and network prices to reflect the different costs of supplying electricity at different times of day (via TOU tariffs). Economic theory suggests that when faced with higher electricity prices at peak times, customers will change their behaviour to shift discretionary electricity consumption into off peak periods. Customers may also reduce their total consumption in response to relatively higher peak prices, although if off-peak prices are reduced due to the transfer to TOU, there may be an offsetting increase in off-peak consumption. Multiple trials and studies have attempted to determine likely customer responses to TOU tariffs (refer to Box 4 below).

The previous analyses of AMI benefits did not attempt to design a likely TOU tariff for Victorian customers and determine associated elasticities. Instead, Futura and Oakley Greenwood estimated that 80% and 30%, respectively, of Victorian customers would take up three-rate TOU tariffs from 2013, and that as a result, those customers would reduce their total consumption by 1.5%.

⁴¹

As customers elect to reduce or shift their energy consumption, potentially some utility is lost. This has not been taken into account in our analysis, due to our view that these innovative tariffs and demand management programs are likely to be well designed such that the loss of customer utility is minimised.

Our discussions with distributors and retailers have revealed limited industry development of TOU tariffs. This hesitancy is largely driven by the current moratorium on the mandatory reassignment of customers to TOU, which is due to end in 2012. In discussions, some retailers indicated that they would pass through network TOU tariffs to all of their customers, others indicated that they would likely manage 100% of the risk associated with network TOU tariffs and not pass TOU price signals through. Distributors are in the early stages of designing network TOU tariffs. We expect that the facilitation of a successful customer engagement program regarding AMI and TOU tariffs and other innovative demand management incentives, combined with the end of the moratorium, will drive retailers and distributors to offer TOU tariffs on a voluntary basis from 2014.

We consider that the general approach applied by Futura and Oakley Greenwood in calculating the energy reductions resulting from TOU tariffs is reasonable, in particular given the current uncertainty around the TOU tariff moratorium and retailer behaviour. To design likely network and retail TOU tariffs and estimate customer responses to those particular tariffs would require a significant number of assumptions, which we consider would undermine the analysis. We consider that selecting a maximum customer response to retail TOU tariffs, based on Australian and international studies and trials, is a reasonable approach.

Accordingly, we have applied a similar approach to estimating energy savings from TOU tariffs. However, we have amended the underlying assumptions for the following variables:

- TOU take up rates – Given the current difficulties surrounding the introduction of TOU tariffs, we consider it prudent to assume that Victorian customers will not be mandatorily reassigned to TOU tariffs, rather that TOU tariffs will be offered on a voluntary basis. Based on international experience of voluntary TOU tariffs, we have assumed that a maximum of 15% of Victorian customers will elect to take up TOU tariffs, increasing from 4% in 2014 to 15% from 2017. The TOU tariffs are assumed to be retail TOU tariffs, noting that this may or may not incorporate network TOU tariffs.
- Total energy reduction resulting from TOU tariffs – Where previous analyses estimated customers on TOU tariffs would reduce their total energy consumption by 1.5%, based on trials and studies we have revised this to 0.1%. We consider that customers will shift their consumption from peak to off-peak times, however that the overall reduction in energy due to TOU tariffs will be minimal. Box 4 outlines the results of some studies into the impacts of TOU tariffs on reductions in overall consumption. While some international studies have found that the introduction of TOU tariffs results in reduced energy consumption, trials done in Australia to date have not found any statistically significant change in overall consumption.

Applying these assumptions results in a maximum reduction in Victorian small customer energy consumption of 0.02%, which is achieved from 2017. It is noted that this benefit encompasses only the impact of TOU tariffs on energy consumption, and that we have incorporated a further reduction in energy consumption due to information delivered by IHDs and enhanced billing as part of a separate benefit below.

In order to convert the assumed energy savings into a value of reduced energy, we have taken Net System Load Profile (NSLP) data from 2008, and assumed energy consumption growth equal to that assumed in AEMO's 2008 Statement of Opportunities (SOO). This approach is consistent with Futura and Oakley Greenwood.

Table 4.13 compares the NPV of our calculated benefits to that calculated by Futura and Oakley Greenwood.

Table 4.13: Benefit from reduced energy consumption due to TOU tariffs (millions, NPV at 2008)

Futura 2010	Oakley Greenwood	Deloitte
123	49	1

Box 4: TOU tariff studies

International studies

International studies have found that a basic TOU tariff program can expect to yield peak energy reductions of approximately 5%, however, the impact of TOU on overall energy usage is limited.⁴² However, it has been estimated that a reduction of 2-5% in system demand at peak times could reduce the spot price of electricity by 50% or more.⁴³

A number of studies have been undertaken in the United States and Canada assessing demand responses resulting from TOU tariffs. Of the studies, the Californian State-wide Pricing Pilot was the most extensive. It included 1861 residential customers assigned to different tariff structures, including 200 participants who were subject to seasonal TOU tariffs. The study found that the reaction in peak period energy use resulting from TOU rates during summer of 2003 equalled -5.9%. However, in 2004 the TOU rate impact almost completely disappeared (-0.6%). If the TOU results are accurate, they suggest that the relatively modest TOU tariff prices (US\$0.09-0.10 for off-peak and \$0.22-\$0.24 for peak) tested in this trial do not have sustainable impacts. The study notes that the TOU sample size was small and there were other complicating factors that mean drawing firm conclusions from these results may not be wise.⁴⁴

Also in the US, Puget Sound Energy found between a 5 and 6% reduction in peak demand from TOU tariffs and a 5% reduction in overall consumption.⁴⁵ In Canada, the Ontario Smart Price Pilot found that the reduction in peak demand was not statistically significant, but that overall consumption was reduced by 6%.⁴⁶ In Northern Ireland a 10% reduction in peak demand has been found from TOU tariffs with a 3.5% reduction in overall consumption.⁴⁷

Australian studies

In Australia, distributors Endeavour Energy (formerly Integral Energy) and Energex have conducted TOU tariff trials. Endeavour Energy found no statistically significant difference in the response of participants paying seasonal TOU tariffs relative to the control group. Trials conducted by Energex have also found no change in peak demand as a result of the introduction of TOU tariffs only.⁴⁸ In Victoria, CRA and Impaq Consulting in 2005 calculated a 10% reduction in peak demand using elasticities drawn from the Californian State-wide Pricing Pilot and assuming a 100% take-up of TOU tariffs.⁴⁹ In Tasmania, the Office of the Tasmanian Energy Regulator (OTTER) estimated a 10% reduction in peak demand using smart meters with TOU tariffs. This estimate was based on customer responsiveness factors that were developed using the observed response of customers in Tasmania to Aurora Energy's 'pay as you go' TOU tariffs.⁵⁰ Overall energy reductions were not reported for these studies.

⁴² Newsham, G. R. & Bowker, B. G. 2010. The effect of utility time-varying pricing and load control strategies on residential summer peak electricity use: A review. Energy Policy, In Press, Corrected Proof

⁴³ Rosenzweig, M. B., Fraser, H., Falk, J. & Voll, S. P. 2003. Market Power and Demand Responsiveness: Letting Customers Protect Themselves. *The Electricity Journal*, 16, 11-23

⁴⁴ CRA, *Impact Evaluation of the California State-wide Pricing Pilot*, 2005.

⁴⁵ FERC, *Assessment of Demand Response and Advance Metering - Staff Report*, August 2006

⁴⁶ Ontario Energy Board, *Smart Price Pilot*, July 2007

⁴⁷ Ofgem, *Domestic Metering Innovation*, February 2006

⁴⁸ NERA Economic Consulting 2008, *Cost Benefit Analysis of Smart Metering and Direct Load Control Work Stream 4: Consumer Impacts Phase 2 Consultation Report. Report for the Ministerial Council on Energy Smart Meter Working Group.*

⁴⁹ CRA and Impaq Consulting 2005 *Advanced Interval Meter Communication Study*

⁵⁰ OTTER, *Costs and Benefits of the Rollout of Interval Meters in Tasmania – Draft Report*, August 2006.

4.6.3.2 Avoided network and generation investment due to peak demand response to TOU tariffs

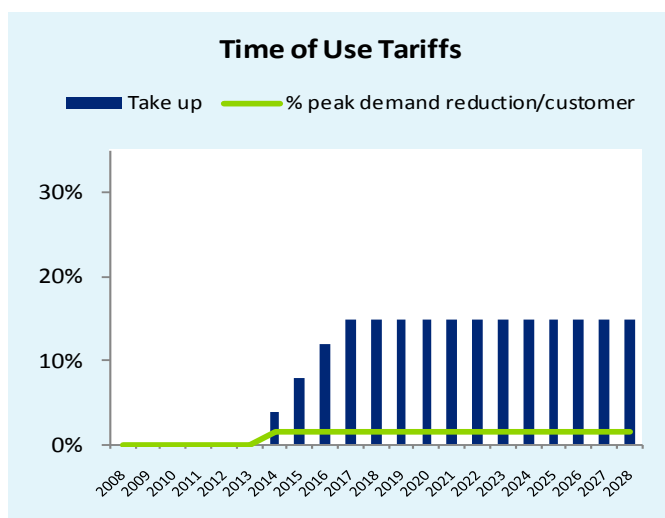
As discussed above, the major benefit of TOU tariffs is the incentive they provide to customers to shift load from peak to off-peak times. Victoria is one of the most peaky electricity markets in the world, meaning a significant amount of network and generation investment is required to supply electricity for the small number of days that reach maximum (peak) demand. The annual load factor for Victorian domestic customers is around 40% and falling over time with the increased penetration of air conditioners.⁵¹ Reducing peak demand results in direct savings in negating or deferring peak driven network and generation investment, which are then passed onto customers.

Futura and Oakley Greenwood applied the same assumptions regarding TOU take up as in their analysis of the energy savings from TOU tariffs (80% and 30% of customers, respectively). Both assumed that those customers that transfer to TOU tariffs would reduce their peak demand by 1.5%. As discussed above, in order to calculate the value of the peak demand reduction, a value of \$200 000/MW/year of avoided peak demand for network and generation investment was assumed.

We have assumed that a maximum of 15% of Victorian customers with an AMI meter will elect to take up TOU tariffs, increasing from 4% in 2014 to 15% from 2017. After considering the previous analyses of peak demand reduction in light of Australian and international experience on TOU tariffs, we consider that the assumed customer response of lowering peak demand by 1.5% is reasonable. International studies have suggested that 5% reduction in peak demand is achievable, however, to date Australian trials have not found any reduction as a result of the introduction of TOU. As such, we consider that 1.5% represents the middle ground (refer to Box 4 above). Applying our assumptions results in a total reduction in Victorian peak demand of 0.1% from 2017, noting that residential customer demand contributes approximately 40% of total peak demand.

We also consider that Oakley Greenwood’s assumed value of avoided peak demand is reasonable, as discussed above in section 4.6.2.3. Figure 4.5 represents our assumed TOU take up rates and impact on peak demand.

Figure 4.5: Assumed TOU take up rates and impact on peak demand



⁵¹ Deloitte analysis based on AEMO net system load profile data. Load factor is defined as the ratio of the average energy demand to the maximum demand during a defined period of time (year).

Table 4.14 compares the NPV of our calculated benefits to that calculated by Futura and Oakley Greenwood.

Table 4.14: Value of avoided network and generation investment due to peak demand response to TOU tariffs (millions, NPV at 2008)

Futura 2010	Oakley Greenwood	Deloitte
89	44	11

4.6.3.3 Avoided network and generation augmentation resulting from critical peak incentives

AMI provides distributors and retailers with the ability to structure pricing incentives to discourage electricity use at times of critical peak demand. Futura’s and Oakley Greenwood’s analyses included benefits associated with the introduction of critical peak pricing (CPP) tariffs, whereby a very high price is declared on a day-ahead basis when periods of extreme demand and high market prices are forecast. Both assumed a CPP tariff take-up rate of 12% (although differed in their assumed profile of customer take-up, with Oakley Greenwood assuming CPP tariffs would be implemented as AMI is rolled out), and demand response rate of 15%. Their assumptions regarding the value of avoided peak demand for TOU tariffs were also applied to this benefit.

There is very limited international experience of CPP tariffs and trials, and there has been notable hesitation on the introduction of CPP by international regulators, due to the implications associated with penalising customers. However, in response to negative customer feedback to the rollout of smart meters in California, critical peak incentives (rewards) for customers to reduce demand at peak times have been approved. It is our view that critical peak incentives are more likely to be considered appropriate for introduction in Victoria than CPP, and have assumed that distributors and/or retailers will follow the Californian developments in critical peak incentives. We have assumed that any Victorian critical peak incentive program will be voluntary. We note that there are a wide number of issues that need to be considered in the development of critical peak incentives, including the assumptions around ‘base’ level consumption against which to compare customer response.

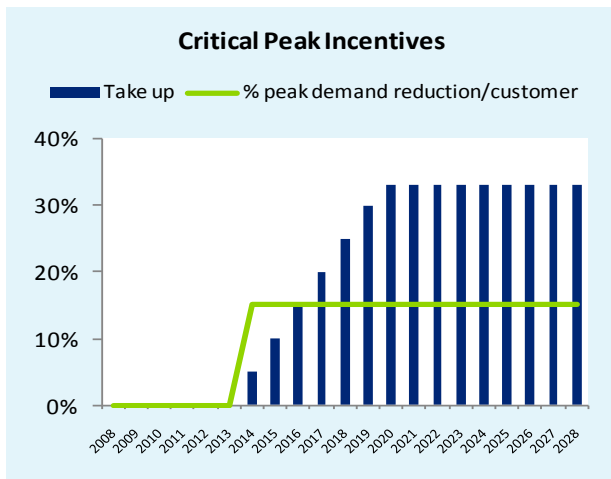
Box 5: International CPP experience

In the California State-wide Pilot Program, participants were exposed to a CPP tariff and were not provided with any automated end-use controls. Under the CPP rate, prices were discounted on non-critical days and participants were given information about how to respond during critical high-price hours. On critical peak days in summer there was a 13.06% reduction in peak demand and 2.4% reduction in overall consumption. During winter the outcomes were 3.91% and 0.62% respectively.⁵² Demand response during CPP events averaged 5.1%; high-use single-family homes responded with an average 7.8 % reduction, while customers in apartments averaged 2.9% and low-use single-family homes 3.2%. Different rates were tested and customer response to the \$0.68/kWh critical-peak price was not higher than response to the \$0.50/kWh critical-peak price, which suggests that as discretionary loads are curtailed, further curtailment becomes increasingly price inelastic.⁵³

Trials conducted in Australia have found higher levels of energy conservation on CPP days than were observed in the Californian Pilot. Country Energy found that it achieved a 25% reduction in peak demand on CPP days and an 8% reduction in overall energy consumption. Preliminary results in trials conducted by EnergyAustralia and Integral Energy found reductions of between 7 and 15%. In both trials, demand was reduced as opposed to just being deferred. It is suggested this is because a large amount of the critical peak usage in Australia is driven by air conditioning, which would not necessarily be deferred and so the energy that would otherwise have been used was saved.⁵⁴

We have assumed that 33% of Victorian customers will voluntarily take up critical peak incentive programs from 2020, each delivering a 15% reduction on their peak demand. Applying our assumptions results in a total reduction in Victorian peak demand of 2% from 2020, noting that residential customer demand contributes approximately 40% of total peak demand. We have used the same assumed value of avoided peak demand as that applied in the TOU tariff benefit above. Figure 4.6 represents our assumed critical peak incentive take up rates and impact on peak demand.

Figure 4.6: Assumed critical peak incentive take up rates and impact on peak demand



⁵² NERA Economic Consulting, *Cost Benefit Analysis of Smart Metering and Direct Load Control Work Stream 4: Consumer Impacts Phase 2 Consultation Report*. Report for the Ministerial Council on Energy Smart Meter Working Group, 2008.

⁵³ Herter, K. & Wayland, S. *Residential response to critical-peak pricing of electricity: California evidence*. *Energy*, 35, 1561-1567, 2010.

⁵⁴ NERA Economic Consulting, *Cost Benefit Analysis of Smart Metering and Direct Load Control Work Stream 4: Consumer Impacts Phase 2 Consultation Report*. Report for the Ministerial Council on Energy Smart Meter Working Group, 2008.

Table 4.15 compares the NPV of our calculated benefits to that calculated by Futura and Oakley Greenwood.

Table 4.15: Avoided network and generation augmentation resulting from critical peak incentives (millions, NPV at 2008)

Futura 2010	Oakley Greenwood	Deloitte
73	133	217

4.6.3.4 Energy conservation from in home displays (IHDs) and enhanced billing

The AMI benefits made possible due to the installation of in home displays (IHDs) are related to the innovative tariff (TOU, critical peak incentives and DLC) benefits outlined above, as some customers are expected to use IHDs to better understand their innovative tariffs and load control. However, international studies have shown that additional information on consumption, absent of any TOU tariffs or critical peak incentives, will drive customers to make additional energy efficiency savings.⁵⁵

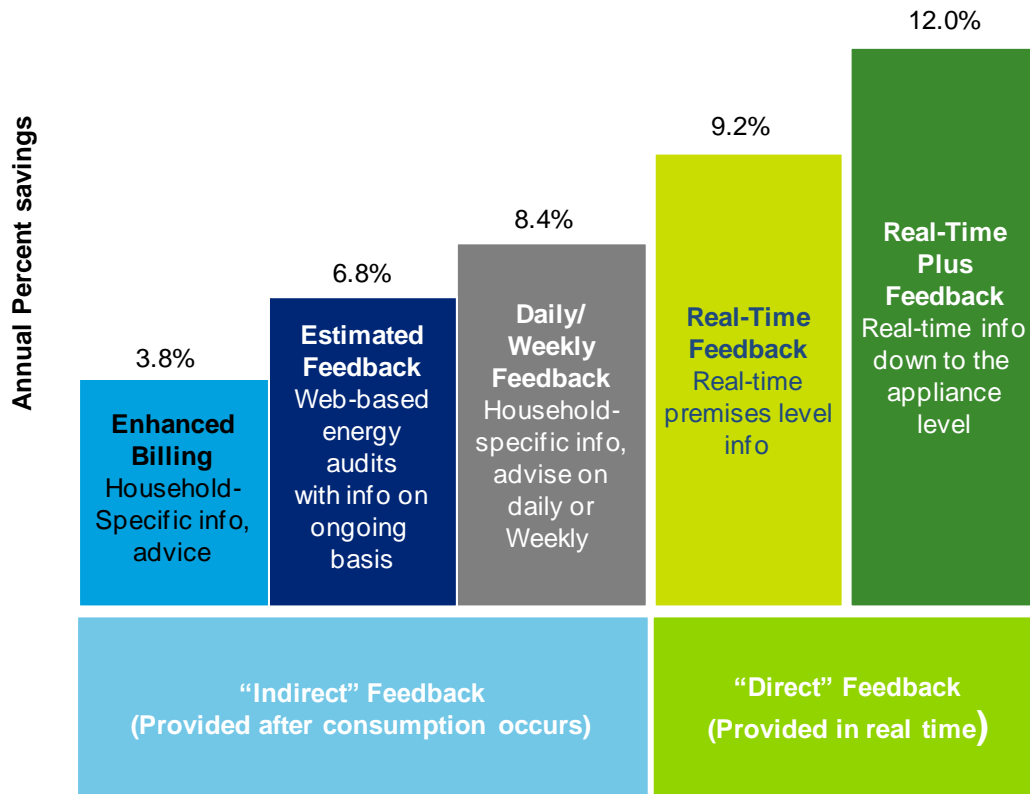
Real time information on consumption is facilitated by IHDs, while enhanced billing is facilitated with an AMI meter only. Enhanced billing involves delivering more detailed information on customer energy use on a more regular basis than the traditional three monthly billing cycle. At best, enhanced billing involves monthly bills, accompanied by detailed information comparing customers' energy use to their neighbourhood, suburb, or city average. The data delivered by AMI has the potential to be used to produce comprehensive comparisons between similar customers (compared on the basis of the number of persons living there, whether they have a swimming pool, gas heating, air conditioner, etc) which can be then communicated back to customers with information on how they can act to save energy. Comparative data has proven to be highly successful in driving customer behavioural change.

The American Council for an Energy Efficient Economy (ACEEE) released a report titled *Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity Saving Opportunities* in June 2010. This report contains data from 57 studies on feedback (or information) effects on domestic customer energy consumption. The report highlights great potential for energy efficiency driven solely by providing more information to customers on their electricity consumption. Figure 4.7 is taken from this report.

⁵⁵

The American Council for an Energy Efficient Economy (ACEEE) *Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity Saving Opportunities*, June 2010

Figure 4.7: ACEEE – customer response to information (feedback)



Based on 36 studies implemented between 1995 - 2010

While we consider that the upper end of the range of estimated customer response to information in the ACEEE report (12%) is likely to be optimistic (and may incorporate some double-counting given it is likely that some customers will be engaged in multiple information programs), we acknowledge that there is great potential for information to drive energy efficient behaviour. At the same time, we also note that the ACEEE is a coalition of parties involved in selling, installing and operating demand response systems, and therefore consider that there may be some optimistic bias in their analysis.

Futura and Oakley Greenwood assumed that 7.5% of customers would receive IHDs, and that those customers would reduce their overall energy consumption by 6%. Oakley Greenwood also added an additional benefit associated with information on consumption delivered by enhanced billing and comparative customer benchmarking. This benefit was calculated on the basis of 70% of Victorian customers receiving information (in addition to IHD information) that would drive a 1% reduction in energy consumption.

We have assumed that the combined take up of IHDs and enhanced billing will reach 25% of customers by 2020, and that those customers will reduce their energy consumption by 6%. We consider this is a conservative estimate, however note that it is extremely difficult to determine separate customer energy reductions in response to IHDs, enhanced billing, TOU tariffs, critical peak incentives and direct load control, and that there is a direct relationship between information and these incentives which could indicate double-counting of customer responses. Accordingly, we consider it is appropriate to adopt a conservative estimate. Applying our assumptions results in a 1.5% reduction in Victorian domestic customer energy consumption from 2022.

In converting energy savings to economic value, we have applied consistent assumptions as in our TOU tariff energy savings benefit (that is, net system load profile and energy consumption growth data from 2008).

Figure 4.8 demonstrates our assumed take up of IHDs and their impact on energy consumption over 2008-28.

Figure 4.8: Assumed IHD take up rates and impact on total energy consumption

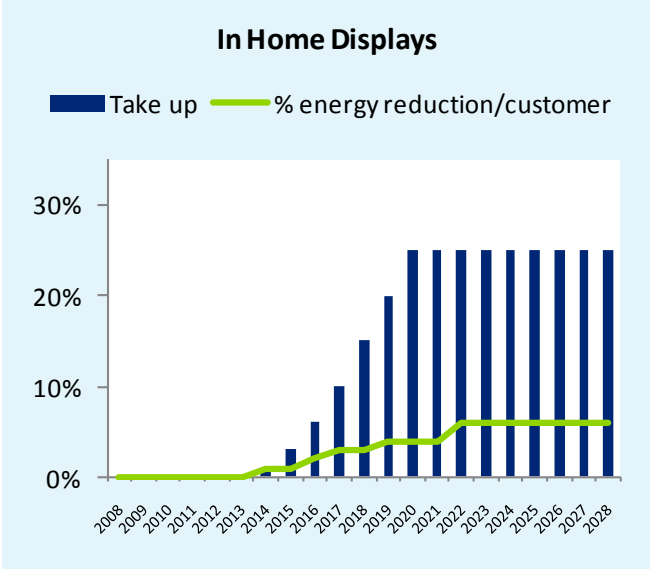


Table 4.16 compares the NPV of our calculated benefits to that calculated by Futura and Oakley Greenwood.

Table 4.16: Energy conservation from in home displays (IHDs) and enhanced billing (millions, NPV at 2008)

Benefit	Futura 2010	Oakley Greenwood	Deloitte
IHDs	50	50	77
Other customer information	0	44	0

4.6.3.5 Reduced peak demand due to direct load control of air conditioners

The Home Area Network (HAN) functionality of AMI meters enables communication between the distributor or retailers, and customer appliances, where those appliances are either ‘smart (Zigbee) enabled’ or are retro-fitted with a communicating device. Direct load control involves using communications devices to limit (reduce or cancel) the supply of electricity to controlled appliances at times of peak demand.

Futura and Oakley Greenwood assumed that 10% of Victorian customers with air conditioners and AMI meters would take up direct load control contracts to enable the management of their air conditioners, and as a result, reduce their peak demand by 19%.

Results from Australian trials suggest that providing customers with positive incentives or rewards for engaging in load control programs to reduce their peak demand can drive significant savings (refer to Box 6 below). Results from voluntary direct load control programs in Utah, Arizona and Nova Scotia indicate customers who opt into load control contracts will reduce their peak demand by 15%.

Box 6: Direct load control

Trials of direct load control in Australia include a pilot study by ETSA Utilities in South Australia, which resulted in a 17% reduction in peak demand from air conditioners in certain suburbs.⁵⁶ Successive results from the ETSA trial concluded that outcomes were dependent on location, housing type and air-conditioner technology and therefore not necessarily effective. In Queensland, Energex found a 12% reduction in peak demand and a 13% reduction in overall consumption for residential customers who were provided with appliance timers that were set to switch appliances off during peak hours. Energex also saw a 34% reduction in peak demand for customers who combined direct load control with a time of use tariff.⁵⁷

Internationally, direct load control programs extend beyond the control of air conditioning. Florida Power and Light (FPL) operates a voluntary direct load control program whereby controls are fitted to five or more appliances in each customer's home. At times of peak demand, FPL selectively controls appliances dependent on the conditions, such that customers are unaware of their appliances being controlled. At times of peak demand, FPL has over 2500 MW of demand at its disposal, reducing peak demand on its network by 10%. This program is highly successful, and demonstrates the potential savings delivered by a well managed, appliance-diverse load control program.

However, given peak demand days in Victoria are always associated with high temperatures, the majority of benefits associated with load control will likely be driven by savings in air conditioner load. As discussed above, we have assumed that in order to participate in direct load control, customers will need to have a device fitted to their air conditioner, at a cost of \$75.

In calculating this benefit, we assumed that a maximum of 25% of Victorian customers would take up direct load control from 2020 (with 1% commencing in 2014), and would deliver savings of 15% on their peak demand. Applying our assumptions on direct load control results in a total reduction in Victorian peak demand of 2% from 2020. In calculating the economic benefit of this reduced peak demand, we have used values consistent with those applied in the calculation of the benefits of peak demand reductions delivered by TOU tariffs and critical peak incentives.

⁵⁶ ETSA Utilities, *Demand Management Program Interim Report No 2*, 2008.

⁵⁷ NERA Economic Consulting, *Cost Benefit Analysis of Smart Metering and Direct Load Control Work Stream 4: Consumer Impacts Phase 2 Consultation Report*. Report for the Ministerial Council on Energy Smart Meter Working Group, 2008.

Figure 4.9 demonstrates our assumed take up of direct load control and impact on peak demand.

Figure 4.9: Assumed take up of direct load control and impact on peak demand.

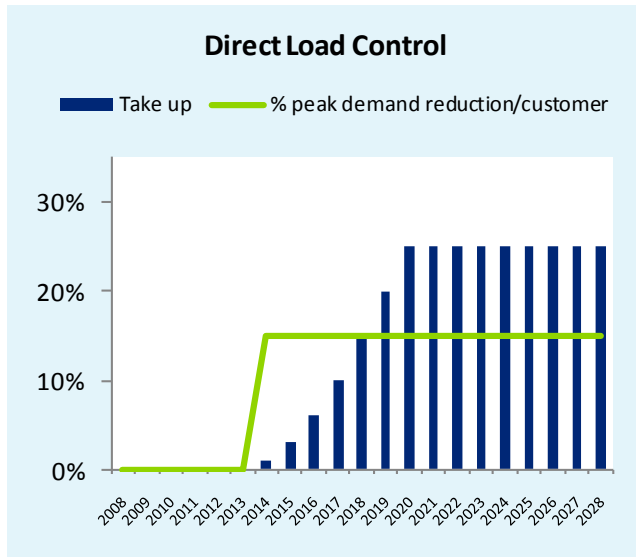


Table 4.17 compares the NPV of our calculated benefits to that calculated by Futura and Oakley Greenwood.

Table 4.17: Reduced peak demand due to direct load control of air conditioners (millions, NPV at 2008)

Futura 2010	Oakley Greenwood	Deloitte
78	177	184

4.6.3.6 Energy conservation from general information programs

Oakley Greenwood added a benefit to account for energy reductions associated with customers receiving general information about energy efficiency, facilitated by AMI. This benefit was considered additional to the benefits derived from information delivered via in home displays, and was associated with enhanced customer billing and the presentation of separate comparative reports regarding customer energy use as compared to their community (neighbourhood or tariff class). Oakley Greenwood assumed that only 7.5% of customers would receive an in home display, yet acknowledged that more than 7.5% of customers would likely respond to information about their energy use due to the interval data facilitated by AMI.

We agree that AMI provides distributors, retailers and other parties with the ability to provide more information to customers regarding energy consumption. As noted above, in our estimates of the impact of in home displays, we have accounted for some additional energy reductions associated with enhanced billing. However, given we have assumed that 25% of customers will receive an in home display, we consider that to add any additional information effect would be double counting the energy savings attributable to information about energy consumption. Accordingly, we have not included any additional benefits associated with general information programs.

Table 4.18 compares the NPV of our calculated benefits to that calculated by Futura and Oakley Greenwood.

Table 4.18: Energy conservation from general information programs (millions, NPV at 2008)

Futura 2010	Oakley Greenwood	Deloitte
0	44	0

4.6.4 Other smaller benefits

In addition to the benefits discussed above, Futura incorporated 18 smaller benefits together contributing less than 5% of the aggregate benefit value. Oakley Greenwood accepted 15 of these benefit calculations without review. Upon review of the remaining three smaller benefits, Oakley Greenwood also accepted Futura's calculations.

As discussed above, we have closely reviewed 16 benefits (including adding an additional benefit associated with the correction of non-technical losses, or theft). Given the smaller magnitude of the remaining benefits, we have also applied a lighter review of the calculations applied by Futura, however have made some amendments where appropriate.

Table 4.19 outlines our consideration of Futura's smaller benefits, as well as the six remaining Futura benefits which were reviewed and accepted by Oakley Greenwood.

Table 4.19: Assessment of smaller benefits (millions, NPV at 2008)

	Futura	Oakley Greenwood	Deloitte	
Revenue from reading smart water meters for water utilities	63	0	0	Not accepted as highly uncertain and depends upon water industry reform and uptake of smart meters
Avoided cost of investigation of customer complaints about voltage and quality of supply, including equipment cost and cost of reporting to regulator	39	39	39	Accepted
Avoided cost of other communications to manage customers' loads for renewable generation tracking, electric vehicle charging and local generation management	37	37	0	Not accepted as highly uncertain, depends upon take up and communications equipment deployed for electric vehicles etc may be different to AMI
Avoided costs of installing import / export metering	35	35	35	Accepted
Peak demand reduction through deferral of refrigerator auto defrost cycle out of peak period	30	30	0	Not accepted, as counted for in direct load control benefit

Reduction in meter data agent costs – putting industrial and commercial customers on distributor AMI networks	26	26	0	Too uncertain as depends upon retailer/meter data agent relationship and access to distributors' AMI network
Avoided cost of investigation of customer complaints of loss of supply which turn out to be not a loss of supply	15	15	15	Accepted
Reduction in calls to faults and emergencies lines	14	14	14	Accepted.
Energy conservation from critical peak incentive implementation	10	10	0	Not accepted, energy conservation is captured in other benefit categories
Reduced cost for post storm supply restoration – avoid delays in detecting and correcting nested outages	9	9	0	Not accepted, captured in outage management benefit category
Reduction in energy trading costs through improved wholesale forecasting accuracy	8	8	0	Not accepted, as improvements in wholesale will result in better matching of peak products across customer classes (domestic and small businesses)
Customer benefit of being able to switch retailer more quickly and more certainly	8	8	8	Accepted
Reduced testing of meters	7	7	7	Accepted, but note that it requires regulatory changes
Reduced cost of network loading studies for network planning	5	5	5	Accepted
Avoided cost of setting demand limits for customers to promote fair sharing and defer augmentation capex	5	5	0	Not accepted as captured in other benefit categories
Avoided cost of replacing service fuses that fail from overload	5	5	5	Accepted
Avoided cost of proportion of HV/LV transformer fuse operations on overload	5	5	5	Accepted
Reduction in calls related to estimated bills and high bill enquiries	5	5	5	Accepted
Avoided cost of supply capacity circuit breaker	4	4	4	Accepted
Avoided cost of end of line monitoring	4	4	4	Accepted
Additional demand response from IHDs at	4	4	0	Not accepted, as captured in IHD

times of critical peak				benefit category
Avoided cost of communications to feeder automation equipment	3	3	3	Accepted
Reduction in the administration cost of bad debt incurred on non-payment on move outs	2	2	2	Accepted
Ability for customers to move to monthly billing on the basis of electronic bills, reducing admin costs, collection costs etc	0	0	0	Not accepted. We consider the more frequent billing could increase admin costs overall.
Total	342.5	279.5	150.5	

Based on our assessment, we have reduced the NPV benefits as proposed by Futura from \$342.5 m to \$150.5 m.

4.6.5 Potential AMI benefits not quantified

The AMI benefits quantified and discussed in this report, while significant, do not fully encompass the benefits that smart metering technology could bring to Victorian electricity networks, retailers and customers. An article published in the June 2008 issue of *Metering International*, titled 'Who benefits from AMI?' identifies over 70 specific benefits of AMI.⁵⁸

A number of potential AMI benefits identified in this article were either technically unquantifiable at present, or would require significant engineering assessments and data collection to quantify for the Victorian distributors. It is noted that in order to achieve some of these benefits, additional expenditure on network equipment, IT and back office systems and training that is not part of the costs incurred and proposed to date may also be required. Key identified but unquantified benefits are outlined in the following sections.

4.6.5.1 Network operations and planning benefits

AMI greatly improves distributors' access to end point data for network management purposes, which will affect and improve almost every aspect of network planning and design. While we have quantified some of the improvements in terms of power quality, outage detection, and general field services efficiency, possible phase and load management improvements have not been determined.

Typically, customers in urban areas are connected to a three phase supply system, and distributors try to maintain an equal load on each phase. AMI provides data on load per phase, which will improve the distributors' ability to correct imbalanced phases for some customers, improving quality of supply. This benefit has proven significant in trials in Ontario, Canada, where distributor HydroOne corrected a sample of customer phase imbalance and achieved 6-7% reduction in peak demand.⁵⁹

In addition, AMI data on load per circuit will enable distributors to more efficiently and accurately segment and move load, improving the quality and security of supply.

⁵⁸ Houseman, Doug, *Who Benefits from AMI?* in *Metering International*, Issue 1 2008.

⁵⁹ Confidential database.

To quantify the load and phase management benefits likely to be realised by the Victorian distributors, detailed studies on the pre-AMI conditions of the networks and quality of supply are needed. Such detailed study is beyond the scope of our analysis in this report, however would be valuable knowledge for the AER in terms of ensuring customers are able to realise these benefits of AMI.

4.6.5.2 Regulatory and reporting benefits

Better network data should improve the general efficiency and accuracy of processes determining efficient regulatory allowances, for both the AER and network businesses. However, it is difficult to estimate this benefit, and in all likelihood it would be minimal.

4.6.5.3 Further customer service benefits

AMI provides retailers and distributors with the ability to more easily and efficiently offer a range of new services to customers at scale. New services that could potentially be offered (without the need for a new meter or related devices) include pre-payment packages for customers who wish to manage their bills, and energy management services to improve customer energy efficiency.

Other potential services that could be provided using AMI following further investment include:

- Appliance monitoring, including medical equipment and home security system monitoring
- Flexible payments for embedded generation, reflecting time of supply, weather conditions, etc.
- Services related to the provision of gas and water, including TOU pricing but also leak detection, flood prevention and gas pressure management.

We have not ascribed a value to these benefits, as they are relatively uncertain and generally rely on additional expenditure being incurred.

4.6.5.4 Stepping stone to smart grid

AMI meters are often considered one of the building blocks for a smart grid. The key features required to enable AMI meters to be a full participant in a smart grid include:

1. A robust, wide area and field area network of smart meters
2. Knowledge of the physical and logical location of each smart meter
3. The ability to have some meters report in an operational time frame, rather than a billing time frame.
4. Additional low latency bandwidth on the wide area network for additional traffic and applications
5. An ability to monitor distributed energy resources and report changes in status in an operational time period
6. The ability to enable demand side management at the individual customer level
7. The ability to communicate autonomously with the network operations centre when conditions at a location fall outside of the accepted operational parameters (e.g. outage, voltage, frequency, etc).

The AMI systems deployed in Victoria are largely capable of meeting these requirements for a smart grid. In some cases, the choice of backhaul communications may limit the ability for the meters to meet the operational time frame for some smart grid related applications. However, aside from this issue, the deployments are technically capable of providing the building block for a smart grid.

Smart grids drive an additional set of network operational benefits that would require additional investment to achieve, and accordingly are not covered in the analysis within this report. Most of the Victorian distributors have made significant moves towards smart grid related activities, including adding automation and switching capability into their networks. Over time, AMI meters can be used to as sensors to improve these smart grid capabilities.

4.6.5.5 Conclusion – Unquantified Benefits

While some of these benefits will accrue to customers over time as competitive retail markets develop, further work to understand, quantify and assess the additional network operational benefits that will accrue to Victorian distributors from the implementation of AMI is recommended, in order to ensure that the benefits are passed back to customers via lower network charges. This may involve conducting extensive trials in conjunction with the Victorian distributors.

4.6.6 Conclusion – Total AMI Program Benefits

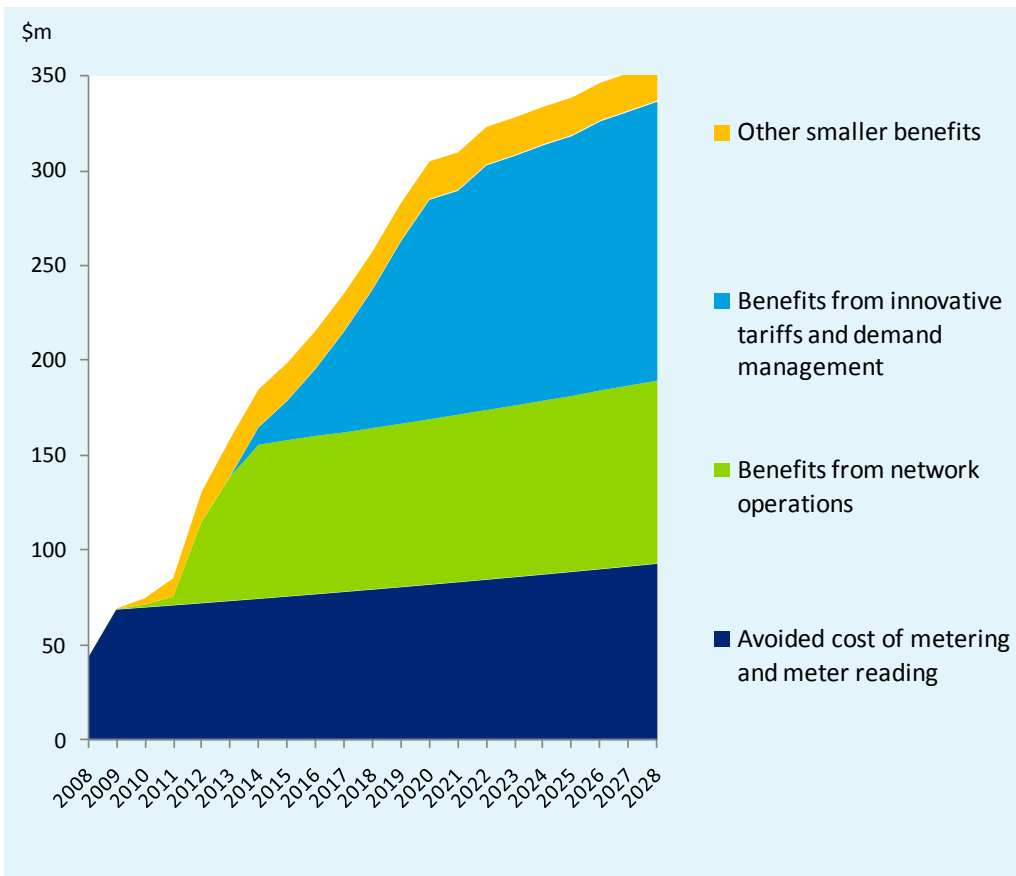
Table 4.20 compares our total benefit calculation to that calculated by Futura and Oakley Greenwood, and Figure 4.10 demonstrates our estimated value of Total AMI Program benefits, and their expected realisation over 2008-28.

Table 4.20: Total AMI Program benefits (millions, NPV at 2008)

Benefit category	Futura	Oakley Greenwood	Deloitte
Avoided costs resulting from AMI Program	855	855	802
Benefits derived from efficiencies in network operations	1 029	956	587
Benefits generated from innovative tariffs and demand management	413	498	490
Other smaller benefits	343	280	151
Total	2 640	2 588	2 030

The figure below presents benefits over time. The key benefits derived from efficiencies in network operations and innovative tariffs start from 2014 (after the smart meter rollout is completed) and ramp up significantly over the next 14 years.

Figure 4.10: Estimated value of Total AMI Program benefits over 2008-28



It is important to note that the method by which benefits will accrue to customers differs among the benefits.

Avoided cost benefits of accumulation metering capex and meter reading costs are already being realised by customers via the approved AMI charges, which incorporate all distributor metering costs. However, given the charges also incorporate costs associated with the accelerated depreciation of accumulation metering stock over the rollout period, the avoided costs are not yet obvious to customers. It is noted that we have assumed some avoided cost benefits commenced being realised in 2008, as distributors avoided replacing accumulation meters as part of their traditional meter replacement cycles, in preparation for the AMI rollout.

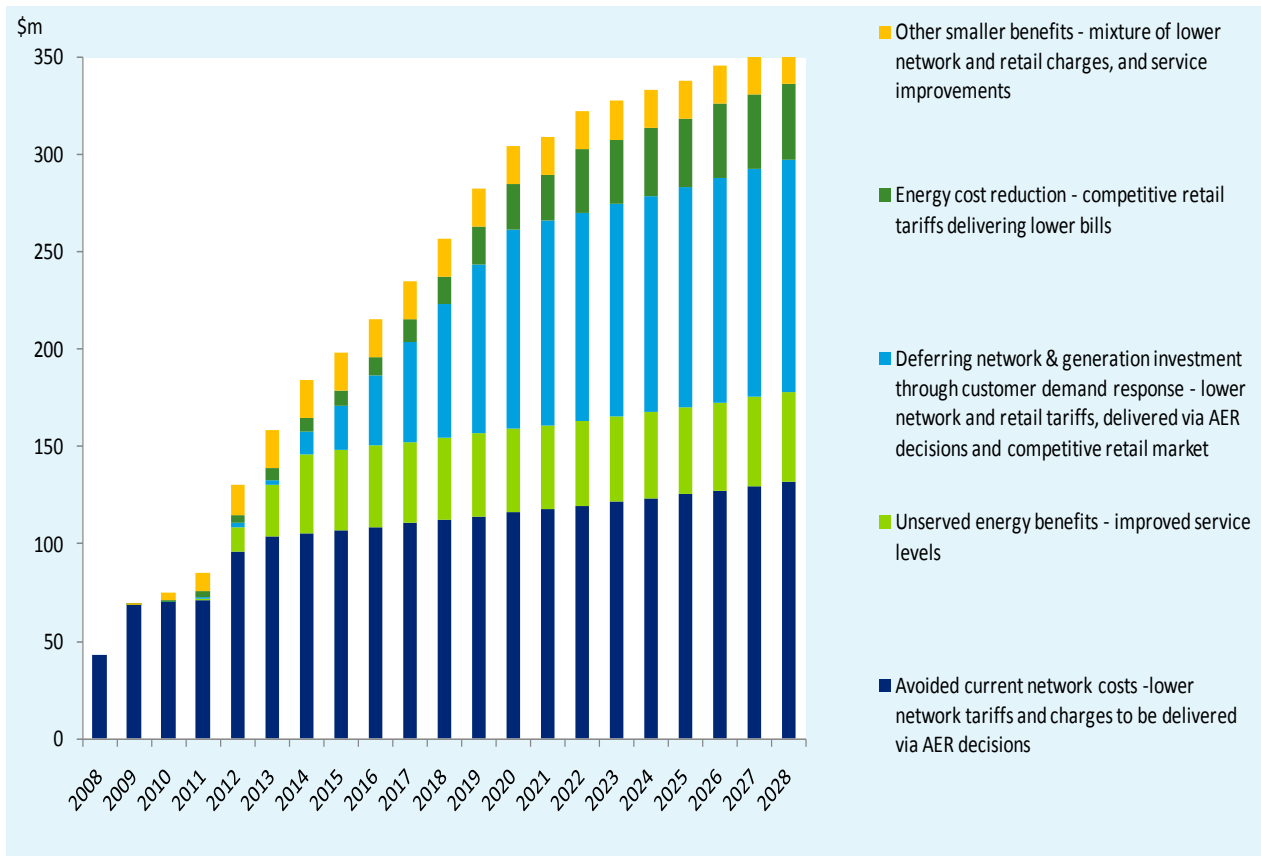
Benefits associated with efficiencies in distributor operations will be realised by customers over time via lower electricity bills, provided that they are reflected in the AER's decisions on distributor operating and capital costs. The AER will need to identify areas where AMI is generating efficiencies in order to pass these benefits onto customers. Any improvements to reliability and service standards generated by AMI will also need to be recognised by the AER, such that targets within the Service Target Performance Incentive Scheme (STPIS) can be adjusted accordingly. Presuming the benefits are identified and passed through to customers, these benefits are likely to impact bills from 2016, once the AER's 2016-20 Victorian Distribution Determination is finished.

Benefits that are generated by innovative tariffs and demand management will be delivered via a number of sources. Benefits associated with network augmentation deferral will accrue via lower network charges (again, dependent on the AER's determinations of charges). The distribution of benefits from deferred generation

expenditure and retail risk management will depend upon the competitive retail market. Given the Victorian electricity retail market is regarded as one of the most competitive in the world, customers can expect that the majority of these benefits will be passed through via lower electricity bills. It is important to emphasise that our calculated benefits generated by innovative tariffs and demand management are based on the assumption that from late 2011, a targeted and sustained customer engagement program is implemented. If this customer engagement program is not undertaken, approximately \$490 million of benefits are at risk.⁶⁰

Figure 4.11 outlines the benefits according to how they are to be realised by customers.

Figure 4.11: AMI Program benefits accrual to customers



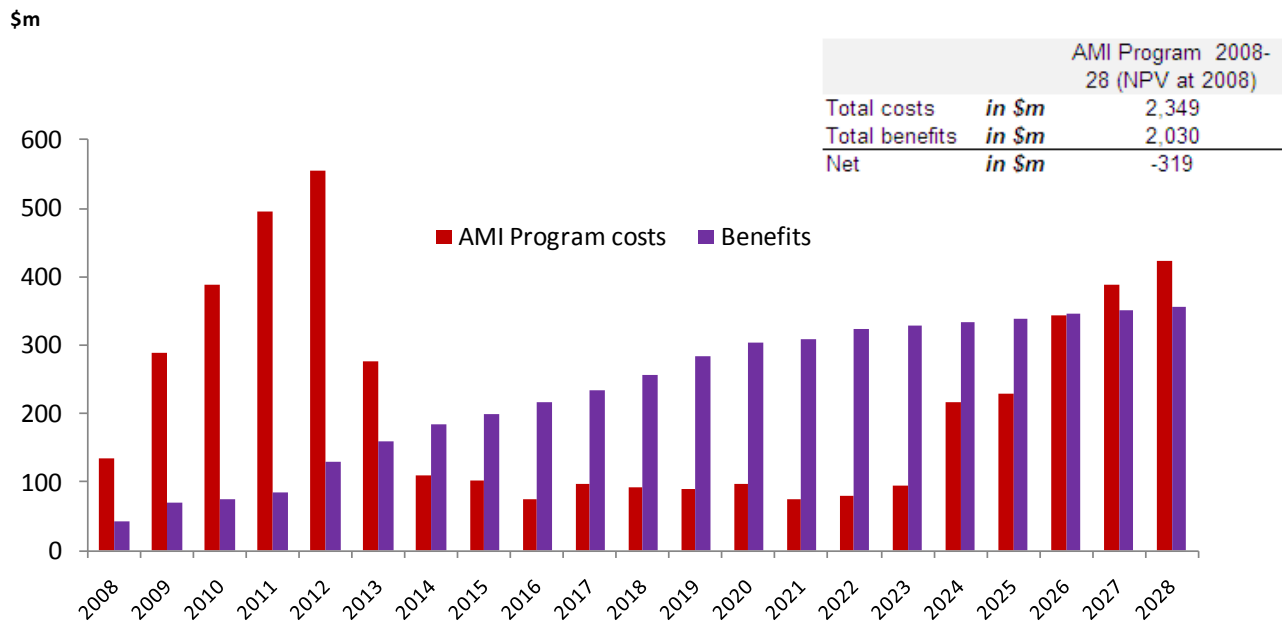
4.7 Conclusion – Costs and benefits of the AMI Program 2008-28

In conclusion, our analysis of the costs and benefits of the AMI Program from 2008-28 concludes that the Program will result in a net cost to Victorian customers of \$319 million, as outlined in Table 20. This negative result is driven largely by the fact that the realisation of benefits has been delayed as compared to previous analyses of the AMI Program, and costs have increased.

⁶⁰ This figure reflects our estimate of the total benefits attributable to innovative tariffs and demand management over 2008-28 (NPV at 2008).

Figure 4.12 presents the profile of AMI Program costs and benefits over 2008-28.

Figure 4.12: Profile of AMI Program costs and benefits 2008-28



4.8 Comparison of findings to previous AMI Program analyses

The results of our analysis have differed from that previously undertaken by Futura, EMCa and Oakley Greenwood. In summary, our analysis of the AMI Program finds that likely costs to customers are higher than previously forecast, while benefits are lower.

As detailed in this report, there are a number of key reasons why our results differ from previous analyses.

Our cost analysis is based on the Victorian distributors’ AMI proposals for 2012-15, which include actual cost data from 2009 and updated forecasts for 2010 and 2011. This is the first analysis conducted with the benefit of a full rollout period cost proposal.

In the previous cost analysis carried out by EMCa in June 2010, adjustments to the distributors’ proposed 2009-11 AMI costs were made to reflect EMCa’s view on the degree to which these costs contributed to an AMI metering asset. In total, EMCa removed \$270 million of non-AMI costs (mainly IT capex and opex, other opex and program management costs) from the distributors’ proposed costs to reflect this view,⁶¹ In April 2011, EMCa updated its AMI Program cost analysis to incorporate the distributors’ 2012-15 AMI budget proposals. This updated report notes that \$505 million of non-AMI costs were removed over 2009-15.⁶² As discussed above, we have also identified some business as usual costs in the distributors’ AMI proposals, and have added these to the

⁶¹ EMCa, *Updated Assessment of AMI Costs for Victoria – A Report to the Victorian Department of Primary Industries (DPI)*, June 2010, p. 11.

⁶² *ibid.* Note that we have not relied on EMCa’s 2011 updated report for any other purposes of this review. All other references to EMCa data refer to EMCa’s 2010 report.

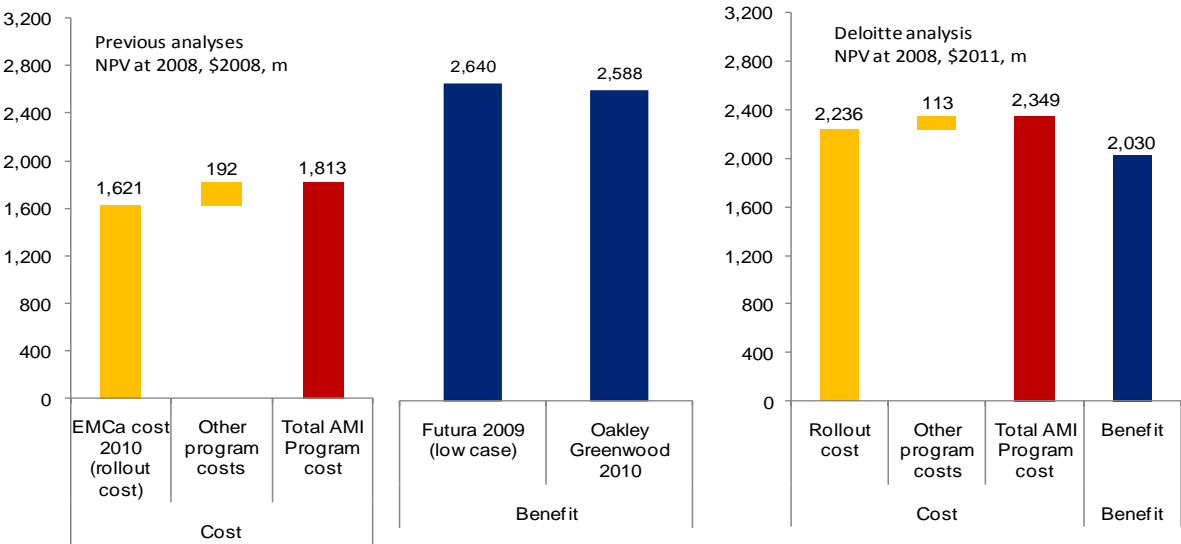
accumulation meter base case (which is then netted off the total AMI Program costs to determine incremental AMI Program costs). Our views on which proposed costs are required to implement the AMI Program differ from those identified by EMCa. Table 4.21 sets out a comparison between Deloitte and EMCa in terms of the business as usual costs removed (or added to the base case) from total AMI Program costs.

Table 4.21: Business as usual costs in distributor’s AMI proposals, EMCa and Deloitte assumptions (total, \$million)

	2009-11 proposed AMI costs removed	2009-15 proposed AMI costs removed
EMCa 2010 and 2011	270	505
Deloitte update 2011	161	277
Difference	109	228

In calculating the AMI Program benefits over 2008-28, we have excluded some categories of benefits included by Futura and Oakley Greenwood which we consider are unlikely to be realised by electricity customers.

Figure 4.13: Comparison to previous analyses of the AMI Program



4.9 Sensitivity analysis

Given our analysis finds the AMI Program over 2008-28 has a net cost to customers, we have carried out sensitivity analysis of some of the core assumptions made in calculating total AMI Program costs and benefits over 2008-28 to test the impact on the net result. In carrying out this sensitivity analysis, we have identified the key value drivers which could significantly improve the economics of the AMI Program. These include:

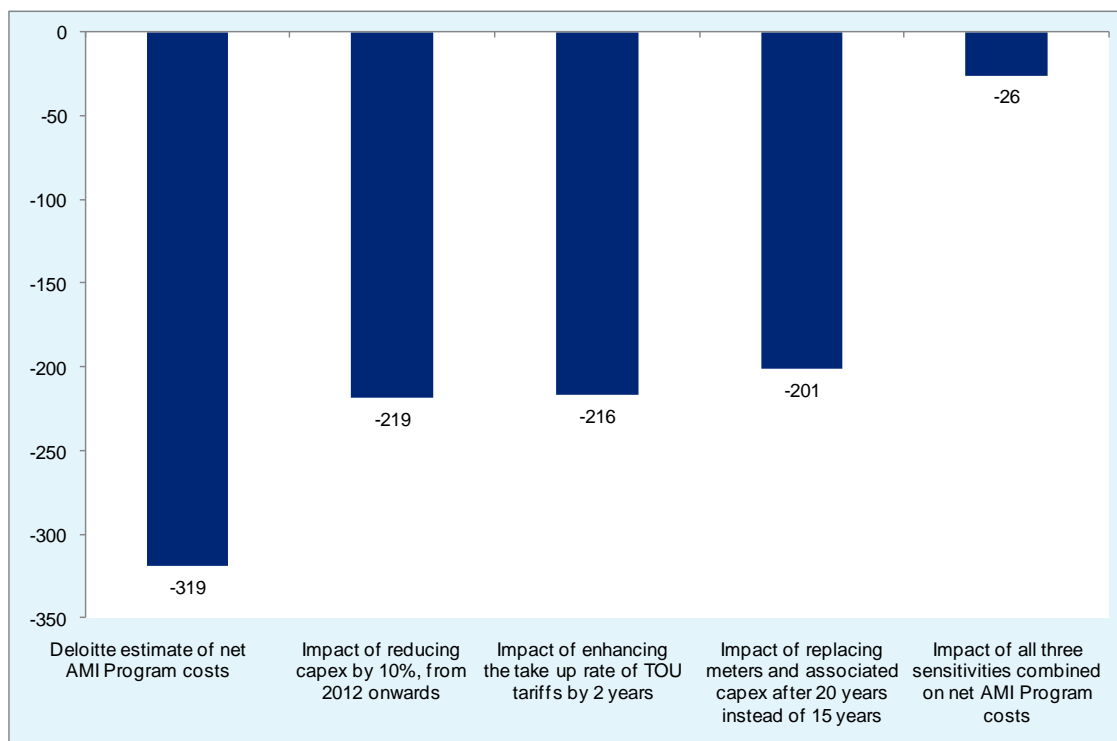
- Capital costs for the AMI Program
- Replacement cycle for the AMI meters
- Take up rates of TOU tariffs, critical peak incentives, direct load control and the deployment of IHDs.

Accordingly, we have tested the following scenarios:

- Reducing distributor proposed capex for 2012-15 by 10% (which also affects capex refresh costs from 2024)
- Assuming take up rates of TOU tariffs commence 2 years earlier
- Assuming that meters and associated capex are refreshed after 20 years (instead of 15 years).

Figure 4.14 outlines the results of this sensitivity analysis, and also shows the impact if all three scenarios eventuated.

Figure 4.14: Sensitivity analysis



4.10 Risks of cost increases

Given the assumptions underpinning our analysis, this section outlines some of the risks to the AMI Program costs and benefits should those assumptions fail to be accurate.

4.10.1 Performance of the technology employed

The latest available data on the performance of the AMI rollout indicates that less than 30% of the AMI meters installed to date are 'live' and communicating wirelessly with the distributors.⁶³ There could be a number of reasons for this low figure, including that the rate of installation of communications network equipment for some distributors is slower than the meters themselves. It is also unclear to what extent the distributors (and therefore customers) are subject to liability in terms of the performance of the communications equipment and meters, as depending on the contracts in place, manufacturers and suppliers of equipment could also be liable to some extent.

However, should significant issues arise in the practical operation of the AMI communications equipment in Victoria, costs to customers of the AMI Program could increase substantially.

Another technology issue that has emerged recently, highlighted within submissions to the DTF's issues paper, is the potential for the Australian Communications and Media Authority (ACMA) to change the radio frequency on which the mesh radio AMI meters communicate. Given the majority of distributors have installed meters that operate within a fixed bandwidth, amending the licensed spectrum could require the retrofitting of installed AMI meters with new communications equipment. This would undoubtedly increase the costs of the AMI Program to Victorian customers.

4.10.2 Regulatory incentive risks

4.10.2.1 AMI OIC treatment of overspends

While the AMI OIC provides that the distributors are able to recover actual costs that are up to 120% of the Approved Budgets for 2010-11 and 110% for 2012-15 without triggering a review of the costs, we have not attempted to estimate any variance from that which was submitted in the Budget Templates to account for budget overspends. The latest cost information indicates that the distributors in aggregate will overspend their 2009-11 Approved Budgets by 18%.

Accordingly, there is some risk that the costs incurred by customers over 2012-15 could be up to 10% higher than proposed costs, based on actual cost data for 2009-11. However, we note that given the distributors will have more experience in installing and implementing AMI meters and systems by 2012, it may be that the proposed budgets contain more accurate cost forecasts than the 2009-11 budget cost forecasts.

4.10.2.2 On-going opex – incentives and risks

As metering is rolled back into the distribution RABs in 2016, the AER will determine the on-going operational costs of AMI as part of its 2016-20 Victorian distribution determinations. The AER's general approach to determining distributors' opex allowances is to establish a base year which represents the historical efficient costs

⁶³ AMI Deployment Dashboard, June 2011.

of operating the network. Adjustments to the base year data are then made to account for network growth, input cost changes and other step changes.⁶⁴

The AER's Efficiency Benefits Sharing Scheme (EBSS) is an incentive scheme developed in 2007 that is applied to distribution opex allowances for distributors across the National Electricity Market. The EBSS provides that any gains or losses achieved by a distributor as a result of actual opex diverging from forecast benchmark opex in one regulatory period are shared with customers in the following regulatory period. The ratio of efficiency sharing between distributors and customers in that subsequent regulatory period is 30:70.

Our view that the distributors' proposed AMI opex for 2014 and 2015 may be approximately 21% overstated, based on international benchmark costs. If this is the case, there is some risk that costs for metering opex incurred by customers could be inflated beyond 2015. If the currently proposed AMI opex for 2015 is approved as annual expenditure over 2016-28, we estimate that the impact of this could be to increase overall AMI Program costs by up to \$192 million (\$2011) over 2008-28, or \$71 million (NPV at 2008). Table 4.22 outlines the effect of this potential risk.

Table 4.22: Impact of assumed opex efficiency from 2016 (\$2011, million)

	Total costs 2008-28	NPV at 2008
Total AMI Program costs with efficiency adjustment applied from 2016	3 482	2 349
Total AMI Program costs with no efficiency adjustment applied from 2016	3 675	2 420
Net – Impact of efficiency adjustment	193	71

Given that future AMI costs are still reasonably uncertain, we therefore suggest that the AER closely consider whether AMI costs should be treated differently to other costs, as far as setting future benchmarks and applying the EBSS is concerned. Applying a different approach may reduce risks to customers as well as distributors (in the event that efficient costs turn out to be greater than forecast).

⁶⁴ AER, *Final decision- Victorian electricity distribution network service providers - Distribution determination 2011–2015*, p. 315.

5. Analysis of costs and benefits: 2012-2028

The key conclusions of this chapter are:

- Despite the total AMI Program over 2008-28 resulting in net costs to customers, due to the fact that by 2012 a substantial proportion of the AMI Program costs will be sunk, a decision to continue to the AMI Program results in net benefits of \$713 million.
- A decision to remove the AMI mandate for distributors to rollout AMI reduces the net benefits to customers to \$343 million (a reduction of \$371 million as compared to continuing the rollout). We consider it likely that, even without the AMI mandate, distributors would continue to install AMI over the next 15 years. We have also assumed that, despite the Government removing the AMI mandate, a customer engagement program is undertaken from late 2011 to maximise the benefits of the infrastructure deployed to date, and minimise cost increases.
- We consider that removing the AMI mandate results in a high risk scenario. We have identified risks associated with customer backlash, rejection of TOU tariffs and other demand management programs, potential further increases in metering capex due to the likely ceasing of current supply contracts.

5.1 Objective of analysis

The second element of our analysis was to provide a platform for Government to make an informed decision about the future of the AMI Program, through presenting the costs and benefits of:

1. Continuing the AMI Program from 1 January 2012
2. Removing the Government mandate for distributors to carry out the AMI rollout (AMI mandate) from 31 December 2012.

This work builds on our analysis of the AMI Program lifecycle costs and benefits from 2008-28, and provides a platform for analysing possibilities for improving the AMI Program in order to bring forward benefits to customers.

5.2 Costs and benefits of continuing the AMI Program from 1 January 2012

In order to test the impact of a Government decision to remove the AMI mandate from 2012, it is necessary to establish the costs and benefits of continuing the AMI Program from 2012. Essentially, this scenario is identical to the AMI Program lifecycle analysis, with costs and benefits taken from 2012 onward.

5.2.1 Costs

We have assumed all AMI Program costs from 2008 to 2011 are sunk. The net present value of costs is from mid-2012 (as compared to the AMI Program lifecycle analysis which calculated the net present value to mid-2008). We have maintained the same assumptions regarding capex replacement from 2024 as applied in the 2008-28 analysis above. Table 5.1 outlines the costs of the AMI Program from 2012 under this scenario.

Table: 5.1 Continuing the AMI Program: costs from 2012

	Sunk costs (2008- mid 2012, million \$2011)	Total over 2012-28 (million, \$2011)	NPV (at 2012, million, \$2011)
Capex	1 152	2 416	925
Opex	342	1 423	785
IHDs and direct load control	0	292	141
<i>Incremental costs</i>	<i>1 494</i>	<i>4 131</i>	<i>1 852</i>
Accumulation meter base case costs (subtracted)	4 67	2 189	1 010
Avoided costs (added for comparison to benefits)	278	1 399	729
Total	1 304	3 340	1 572

5.2.2 Benefits

Similar to the benefits analysis under the 'Slowing the pace' scenario discussed below, given very limited benefits will have been realised before 2012, benefits attributable in this scenario are equal to the total AMI Program lifecycle benefits. However, given the net present value of benefits is from mid-2012, there is a small increase in total benefits. Table 5.2 outlines the benefits of the AMI Program from 2012. More detailed information on the benefits of continuing the AMI Program from 2012 is provided in section 5.3.

Table 5.2: Continuing the AMI Program: benefits from 2012

	NPV (at 2008, million, \$2011)	NPV (at 2012, million, \$2011)
Total benefits	2 030	2 285

5.3 Costs and benefits of removing the mandate for the AMI rollout – 'Slowing the pace'

In determining the impact of a Government decision to remove the mandate for distributors to implement AMI, we have made some assumptions about when the decision would be made and when it would affect costs to customers. Due to the anticipated outcome of removing the Government mandate for distributors to implement AMI, in this report we have referred to this scenario as 'Slowing the pace'.

We have assumed that this decision would be made at the beginning of October 2011. This date is based on our expectation of the timeframe for decision making. Given the distributors' are generally contracting for their supplies of metering and other equipment six months in advance, we anticipate that the rollout would effectively cease from 1 April 2012.

5.3.1.1 Assumptions on cost recovery to date

For the purposes of our analysis, we have assumed that annual costs within the distributors' budget templates have been recovered from customers in the same year that they are assumed to be incurred. It is noted that this is not actually the case, as actual costs for any year are not known until the following year. As part of the AER Budget and Charges Determinations, placeholder charges are established by the AER for each year (t), and then when actual costs are known in year (t+1), placeholder charges for year (t+2) are adjusted to account for any departures from forecast costs. This means that by end 2012, customers will have paid actual costs for 2009 (in their 2011 charges), and estimated charges for 2010 and 2011. This is complicated further by the fact that the distributors can elect to under or over recover costs on any year, which all distributors have done to date.

In analysing the 'Slowing the pace' scenario, we have assumed that the Government decision to remove the mandate for the AMI rollout also enables the distributors to fully recover the costs incurred up until that date (being 1 October 2011, also accounting for any forward orders of supplies). In effect, this means that in calculating the total costs to customers of the scenario, the costs recovered in tariffs to date are somewhat irrelevant.

We have also assumed that in deciding to remove the mandate for the AMI rollout, the Government amends the AMI OIC (or another legislative instrument) to enable the distributors to continue recover their on-going metering costs, given without doing so, there would be no cost recovery for on-going accumulation metering costs between 2012 and 2016 when the AER's next Victorian distribution determination comes into effect.

The impact of a Government decision to remove the mandate for the AMI rollout and not enable distributors to recover their costs incurred to date has not been estimated as part of our analysis. Similarly, the impact of a Government decision that current AMI charges cannot be increased from 2011 levels has not been estimated. We note that these scenarios could be costed in analysing options for the future of the AMI Program (Work Stream 2).

5.3.1.2 Assumed distributor responses to decision

Internationally, the provision of electricity metering is changing. While Victoria is the world's largest scale smart meter rollout to date, utilities across the US, Europe and Asia are replacing accumulation meters with smart, wireless communications enabled interval meters. Anecdotally, we understand that metering manufacturers have started changing their products to meet demand for smart metering. Domestically, the National Smart Metering Program (NSMP) is moving forward in developing frameworks to enable other state jurisdictions to mandate smart meter trials and rollouts in NSW and Queensland.

By the end of 2011, the distributors will have installed AMI meters to almost 50% of Victorian small customers. The AMI communications network for at least two of the distributors will be almost completed (the remaining distributors are installing their communications network in line with the meters installed). AMI IT systems will be around two thirds complete. Some distributors have already shifted all their customers onto new IT and billing systems, while other distributors are gradually retiring the old systems and moving customers across to AMI. Given the shift towards AMI has been anticipated since 2006, distributors have not invested in maintaining their accumulation metering and related IT systems.

Given this, the costs of returning to an accumulation metering base would not be insignificant. The additional costs of operating and maintaining a hybrid accumulation and AMI metering network are also not insignificant.

However, distributor cost recovery for any AMI costs incurred following a decision to remove the mandate for the AMI rollout is currently uncertain. Distributors would need to be satisfied that continuing to invest in AMI, and install AMI meters for new and replacement sites is consistent with the capex and opex criteria within the National Electricity Rules, in order to ensure efficient cost recovery.

Based on experience in other jurisdictions and information gathered in our discussions with distributors, and provided that sufficient regulatory certainty is provided, it is our view that should the Government decide to remove the mandate for distributors to rollout AMI, distributors will not revert to installing accumulation meters or manually read interval meters on a new and replacement basis.

We have assumed that the distributors will continue to replace their remaining accumulation meters with AMI over the next 15 years, with full AMI achieved in 2027, accordingly 'Slowing the pace' of the AMI rollout. However, in our analysis we have not assumed that distributors will avoid replacing the last 5% of accumulation meters, although this is a possibility if the incremental costs of reaching difficult sites (especially for the rural distributors) outweigh the benefits of doing so. At present, we do not have enough information to determine the cost impact of avoiding the most expensive sites. This aspect may require further analysis in Work Stream 2.

We have assumed that the distributors will complete their AMI communications and IT rollouts over 2012-15. Our assumptions regarding the likely operating costs of this 'Slowing the pace' scenario are directly related to the decisions around capex. We have also assumed that the distributors will continue to install AMI meters on the basis that they are enabled to recover their new and replacement AMI metering, IT and communications costs over 2012-15. From 2016 onwards, we assume that the AER will enable the distributors to recover the costs of AMI for new and replacement sites, where proposed costs are consistent with the requirements of the National Electricity Rules.

5.3.2 Costs

In order to forecast the likely costs under the 'Slowing the pace' scenario, we have used our analysis of the total lifecycle AMI costs as a starting point. As discussed above, we have assumed that distributor AMI Program costs from 2008-11 are sunk, and are therefore removed from the cost calculations.

Identical assumptions regarding the likely future costs of capex and opex that were made in our AMI Program lifecycle analysis were applied to the costs from 2012 (including identical assumptions regarding asset lives for meters and IT systems), with the following adjustments:

- Metering capex—Assumed that 25% of costs proposed in 2012 would be incurred (covering the six months of orders after the Government decision), with the remainder of rollout costs (being the proposed metering and installation costs for 2012-13) incurred over fifteen years, 2013-27. We have assumed that metering capex costs under the 'Slowing the pace' scenario will be higher than under the AMI Program, as distributors will be locked into purchasing communications cards (within the AMI meters) from their original communications suppliers. We anticipate that given the lack of competition in the market and the fact that the supply contract for the mass rollout will no longer be valid, the costs of these cards will increase by \$50 per meter.
- IT capex—Assumed that Field Scheduling and Mobility costs would not recur beyond 2015.

- Program management—Assumed that costs for Program Management Office, business implementation and IT Program Management will not be incurred beyond 2012.
- IT opex—We have assumed that the distributors would complete their AMI IT programs despite the AMI mandate being removed, and accordingly ongoing IT opex under the 'Slowing the pace' scenario is identical to that under the AMI Program costs.
- Other opex—Meter Data Services, meter reading, meter maintenance and customer services costs were calculated based on a hybrid of the AMI Program lifecycle and accumulation meter base case costs, calculated proportionally based on the number of AMI meters installed over 2012-28. Backhaul communications costs were assumed to increase according to the proportion of AMI meters installed. Communications opex was assumed to be equal to the AMI Program costs, given it is assumed that the distributors will complete their AMI communications networks.
- Ongoing opex efficiencies - The efficiency applied to post 2016 opex in the AMI Program lifecycle costs in order to bring the distributors' proposed 2015 on-going opex into line with benchmark operating costs has not been applied in the 'Slowing the pace' scenario. Based on international experience, operating in 'mixed mode' (some accumulation meters, some smart meters) results in a premium of 23% on costs that would otherwise be incurred. As we have calculated ongoing opex on the basis of the accumulation:AMI meter ratio over 2012-28, in order to account for the inefficiency of mixed mode operation, we have not applied the on-going opex efficiency adjustment applied to the AMI Program lifecycle costs.

In conclusion, total costs under the 'Slowing the pace' scenario are outlined in Table 5.3.

Table 5.3: Slowing the pace: costs from 2012

	Total over 2012-28 (million, \$2011)	NPV (at 2012, million, \$2011)
Capex	1 645	709
Opex	1 610	870
IHDs and direct load control	202	96
<i>Incremental costs</i>	<i>3 457</i>	<i>1 675</i>
Accumulation meter base case costs (subtracted)	2 189	1 010
Avoided costs (added for comparison to benefits)	1 399	729
Total	2 666	1 394

5.3.3 Benefits

While approximately 50% of the AMI Program costs will be sunk at the end of 2011, conversely, the majority of benefits associated with the AMI Program will not have been realised.

As described above, we have assumed that distributors will continue to install AMI meters over 2012-27 in response to a Government decision to remove the mandate for the AMI rollout. The effect of this decision will be

to delay the realisation of AMI Program benefits, however, all incremental benefits associated with AMI will be realised once the AMI network is complete in 2027.

The estimated impact on AMI benefits of the decision to remove the mandate differs according to the categories of benefits discussed in the AMI Program lifecycle analysis above. Accordingly, rather than discounting the overall benefits under this 'Slowing the pace' scenario, we have applied a detailed analysis to each category of benefits to determine the likely impact.

5.3.3.1 Avoided costs associated with accumulation meters resulting from the AMI Program

Given we have assumed that the distributors will continue to replace their accumulation metering stock with AMI meters over 2012-27, the aggregate avoided costs associated with accumulation meters under the 'Slowing the pace' scenario are equivalent to the total AMI Program lifecycle avoided costs.

The only difference between the calculated avoided costs under the AMI Program lifecycle and the 'Slowing the pace' scenario is due to the impact of shifting the net present value from 2008 to 2012.

Table 5.4 presents the benefits attributable to the avoided costs of accumulation metering capex and meter reading under the AMI Program and 'Slowing the pace' scenario.

Table 5.4: Post 2012 analysis: Avoided cost benefits of AMI (millions, \$2011)

Benefit	AMI Program 2008-28 (NPV at 2008)	AMI Program 2012-28 (NPV at 2012)	'Slowing the pace' (NPV at 2012)
Avoided cost of replacing accumulation meters	649	581	581
Avoided cost of replacing time switches	Incorporated within avoided cost of replacing accumulation meters	n/a	n/a
Avoided cost of manual meter reading	154	148	148
TOTAL	802	729	729

5.3.3.2 Benefits derived from efficiencies in network operations

As discussed above, it is our assumption that a Government decision to remove the AMI mandate would result in the gradual replacement of accumulation meters with AMI over 2012-27. Given this, the benefits associated with improved network operations would still be realised in the timeframe of our analysis, but would take much longer.

To account for this, in calculating the benefits under the 'Slowing the pace' scenario, we have lagged the realisation of network operational efficiency benefits in line with the assumed gradual rollout of AMI meters over 2012-27. As for other benefits, shifting the NPV analysis from 2008 to 2012 results in higher benefits from 2012 in NPV terms.

This has significantly affected the benefit associated with the ability to set emergency demand limits at times of network stress or constraint, as these benefits will not be realised until the AMI rollout is completed in 2027.

Table 5.5 illustrates the impact of 'Slowing the pace' on the total benefits derived from network operational efficiencies in NPV terms.

Table 5.5: Post 2012 analysis: Network operational efficiency benefits (millions, \$2011)

Benefit	AMI Program 2008-28 (NPV at 2008)	AMI Program 2012-28 (NPV at 2012)	'Slowing the pace' (NPV at 2012)
Reduction in unserved energy due to faster detection of outages and restoration times	66	83	32
Remote special reads and remote disconnections	149	187	146
Remote reconnections	209	263	205
Avoided additional cost of energy from time switch clock errors	26	30	23
Savings from reduction in non-technical losses (theft)	27	33	26
Avoided cost of proportion of transformer failures on overload and avoided unserved energy	29	34	26
Ability to set emergency demand limits to share limited supply at times of network stress or shortage	82	103	4
Total	587	733	461

5.3.3.3 Benefits generated by innovative tariffs and demand management

We consider that there is considerable uncertainty on the likely customer behavioural impacts of a Government decision to remove the AMI mandate. Removing the mandate may indicate to customers that the Government does not have faith in the benefits of smart metering technology, and could undoubtedly affect the customer take-up rates of innovative tariffs and other demand management activities. We have assumed that despite the Government's decision to remove the AMI mandate, the continual replacement of accumulation meters with AMI by distributors would still encourage the development of a market for IHDs and other innovative retail tariff options (provided the retailers consider it is in the customers interest and desirable to offer such products, and that there are no regulatory barriers to these products being offered voluntarily and competitively).

Accordingly, the assumed impact of a Government decision to remove the AMI mandate on benefits generated by innovative tariffs and demand management is a delay in the take-up rates by between four and six years. Continuing the AMI Program would result in customer engagement in TOU tariffs, critical peak incentives, direct load control and IHDs commencing from 2014 with maximum benefits realised from 2020. By comparison, we have assumed that 'Slowing the pace' results in maximum customer engagement commencing in 2026, with rates of engagement from 2014 at approximately half of that assumed under the AMI Program benefits analysis. Our assumptions regarding take-up rates are detailed in Appendix A.

As for other benefits, shifting the NPV analysis from 2008 to 2012 results in higher benefits from 2012 in NPV terms. Table 5.6 illustrates the impact of 'Slowing the pace' on the total benefits derived from innovative tariffs and demand management in NPV terms.

Table 5.6: Post 2012 analysis: Innovative tariffs and demand management (millions, \$2011)

Benefit	AMI Program 2008-28 (NPV at 2008)	AMI Program 2012-28 (NPV at 2012)	'Slowing the pace' (NPV at 2012)
Energy conservation from time of use (TOU) tariffs	1	1	1
Avoided network and generation augmentation due to peak demand response to TOU tariffs	11	14	10
Avoided network and generation augmentation resulting from critical peak pricing incentives	217	273	155
Energy conservation from in home displays (IHDs) and enhanced billing	77	96	67
Reduced peak demand due to direct load control of air conditioners.	184	232	147
Total	490	617	380

5.3.3.4 Other smaller benefits (incorporating minor efficiencies in network and retail operations)

In calculating the remaining smaller benefits associated with AMI under the 'Slowing the pace' scenario, we have lagged the realisation of benefits according to the assumed gradual rollout of AMI meters over 2012-27.

As for other benefits, shifting the NPV analysis from 2008 to 2012 results in higher benefits from 2012 in NPV terms. Table 5.7 illustrates the impact of 'Slowing the pace' on the remaining smaller benefits in NPV terms.

Table 5.7: Post 2012 analysis: Smaller benefits (millions, \$2011)

Benefit	AMI Program 2008-28 (NPV at 2008)	AMI Program 2012-28 (NPV at 2012)	'Slowing the pace' (NPV at 2012)
Avoided cost of investigation of customer complaints about voltage and quality of supply, including equipment cost and costs of reporting to regulator	39	53	42
Avoided costs of installing import / export metering	35	48	38
Avoided cost of investigation of customer complaints of loss of supply which turn out to be not a loss of supply	15	20	16
Reduction in calls to faults and emergencies lines	14	19	19
Customer benefit of being able to switch retailer more quickly and more certainly. (Note: this is not the bill saving)	8	11	9

Reduced testing of meters	7	10	8
Reduced cost of network loading studies for network planning	5	7	5
Avoided cost of replacing service fuses that fail from overload	5	7	5
Avoided cost of proportion of HV/LV transformer fuse operations on overload	5	7	5
Reduction in calls related to estimated bills and high bill enquiries	5	6	5
Avoided cost of supply capacity circuit breaker	4	5	4
Avoided cost of end of line monitoring	4	5	4
Avoided cost of communications to feeder automation equipment	3	4	3
Reduction in the administration cost of bad debt incurred on non-payment on move outs	2	3	2
Total	151	205	166

In conclusion, total likely AMI benefits associated with 'Slowing the pace' are outlined in table 5.8.

Table 5.8: 'Slowing the pace': benefits from 2012 (millions, \$2011)

Benefit category	AMI Program 2008-28 (NPV at 2008)	AMI Program 2012-28 (NPV at 2012)	'Slowing the pace' (NPV at 2012)
Avoided costs resulting from AMI Program	802	729	729
Benefits derived from efficiencies in network operations	587	733	461
Benefits generated from innovative tariffs and demand management	490	617	380
Other smaller benefits	151	205	166
Total	2 030	2 285	1 736

5.3.4 Additional risks of 'Slowing the pace' scenario

It is our view that a Government decision to remove the AMI mandate from 2012 would generate a high risk scenario for all stakeholders. We have identified three additional risks that could result from the 'Slowing the pace'

scenario. While we have not quantified the impact of these additional risks in calculating the overall costs and benefits of the 'Slowing the pace' scenario, we consider it is necessary to acknowledge the potential worst-case outcomes here.

5.3.4.1 Customer backlash – costs imposed by customers refusing AMI meters

Since January 2011, the rate of customer refusals to have an AMI meter installed has risen from 2.3% to 8% of installed meters.⁶⁵ Should the Government announce that it intends to remove the AMI mandate, we consider that the refusal rates for AMI meters will significantly increase. We note that recent media articles relating to AMI have served to enhance opposition to the AMI Program.

Given we assume that in response to a Government decision to remove the AMI mandate, distributors will not revert to accumulation meters, rather they will continue to install AMI meters over 2012-27, a significant rate of customer refusals of AMI meters will impact on the distributors' costs, particularly in the years immediately following the decision. Customer refusals could impact on the distributors' ability to finish their contracted meter supply and installation programs (which we have assumed will end at the end of March 2012, given procurement typically occurs six months in advance).

We have not calculated the potential costs associated with the risk of growing customer backlash. Box 7 outlines a case study of potential tariff outcomes of customer refusal to accept smart meters in California.

Box 7: Pacific Gas and Electric Company

Concerns regarding the health impacts of smart meters originated among San Francisco distributor Pacific Gas and Electric Company's (PG&E) customers. The California Public Utilities Commission (CPUC) has worked with PG&E in responding to customer concerns.

Due to the significant customer concerns regarding RF radiation, in March 2011, at the request of the CPUC, PG&E created a tariff class for customers who wished to opt out of smart meters. This tariff incorporates the actual costs of carrying out manual meter reading for these customers, where they are scattered throughout the PG&E service territory. The aim of the tariff is highlight the costs imposed by opting out of the smart meter program, and to prevent cross subsidisation.

PG&E proposed two tariff options for customers opting out of the smart meter program:

1. An initial fee of US\$270 to exchange the smart meter, and a monthly meter reading fee of US\$14
2. An initial fee of US\$135 to exchange the smart meter, and a monthly meter reading fee of US\$20

These tariffs reflect the full cost of an incremental customer opting out of the smart meter program, with the first option being fully cost reflective, the second spreading the cost of the meter exchange out over the year.

The tariffs have not yet been approved by the CPUC. In June 2011, the regulator in Maine adopted a similar tariff scheme.

In our view, a decision to remove the AMI mandate would impede any potential customer engagement, regardless of any advertising or community engagement process. The impact of the mixed message of the Government removing the mandate for the mass rollout as well as a customer engagement program may be confusion on the part of customers, and would probably increase the cost of any customer engagement program. Any net gains

⁶⁵ AMI Program Deployment Dashboard, 31 May 2011 and 31 January 2011.

due to 'Slowing the pace' of the AMI rollout could potentially be lost in the increased costs of a customer engagement program.

5.3.4.2 Potential for tariff and other customer engaged benefits to be delayed further

Our assumptions regarding the take-up rates for TOU tariffs, critical peak incentives, direct load control, IHDs and enhanced billing under the 'Slowing the pace' scenario rely on customer engagement (as described in section 4.4.5) and a number of retail market developments, which are highly unpredictable.

We have assumed that a Government decision to remove the AMI mandate will not significantly impede retailers' ability to offer innovative tariffs and demand management programs to customers using AMI. Depending on the customer response to AMI meters following the Government's decision, the market could take longer to recover than that assumed here.

In a worse-case scenario, significant customer backlash on the take up of TOU tariffs, critical peak incentives, direct load control, IHDs and enhanced billing could place \$380 million (NPV at 2012) of total benefits under the 'Slowing the pace' scenario at risk.⁶⁶

5.3.4.3 Significant increases in costs of meter capex

As noted above, should the distributors be forced break their current contracts with their AMI metering suppliers, we have anticipated that the costs of the communications cards would increase by approximately \$50 per meter due to the lack of competition in the market.

While we have allowed for a \$50 increase, it is worth noting that given the position that the Victorian distributors would be in, with around 50% of their meters and all the related communications equipment already installed under the mass rollout, the costs for completing the AMI network could be up to 200% of the current supply costs.

However, it is also foreseeable that the distributors may elect to complete their current contracts with metering suppliers and warehouse the AMI equipment for installation over 2013-27. This would also impose some costs associated with storing the meters.

Approximately 600 000 two element AMI meters (which are needed to maintain the current tariff arrangements for customers with off peak rates for hot water or slab heating) need to be installed over the AMI rollout. As Victoria is the only jurisdiction in the world installing two element AMI meters, there is only one manufacturer producing these meters. Should the current contracts established for the mass rollout be cancelled, we anticipate that the supply costs of two element AMI meters could increase significantly. This is further complicated by the fact that for all distributors, the implementation of two element AMI meters has been delayed. In our view, it would not be surprising if, if slowed to an installation rate of 60,000 a year (over a 10 year replacement), the price for two element meters doubled from that currently projected. We have not included any increased costs for two element meters in the 'Slowing the pace' scenario.

5.4 Conclusion – Incremental costs and benefits from 2012

Our modelling of the impact of a Government decision to remove the AMI mandate from late 2011, as compared to continuing to the AMI Program, suggests it would result in a net cost to customers of \$371 million.

⁶⁶ This figure reflects the total benefits attributable to innovative tariffs and demand management under the 'Slowing the pace' scenario.

As discussed above, the differences between the 'Continuing the AMI Program' and 'Slowing the pace' scenarios are driven by the following assumptions in the 'Slowing the pace' scenario:

- meter supply cost increases, driven by the cancellation of current supply contracts
- the lagged uptake of benefits associated with AMI network coverage and innovative tariffs and demand management.

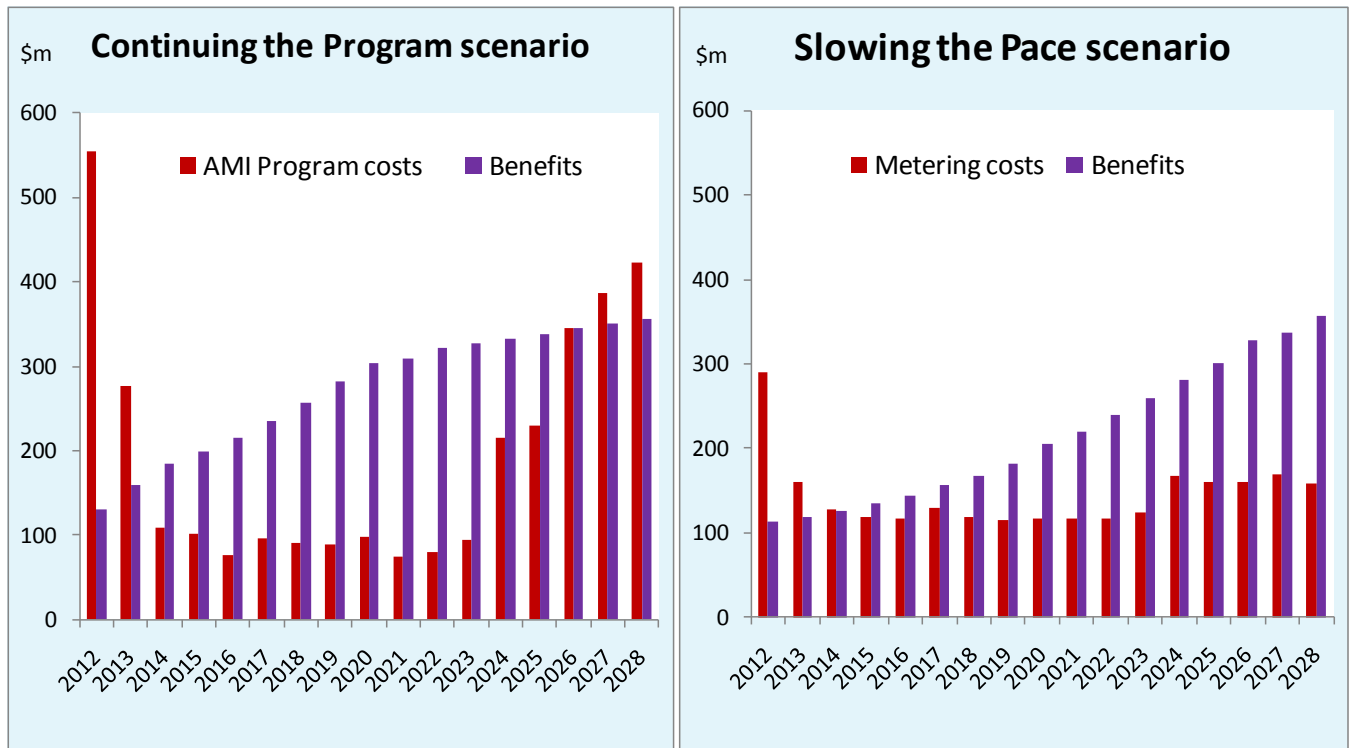
Figure 5.1 presents the findings of our analysis of 'Slowing the pace' from 2012 as compared to continuing the rollout as currently mandated.

Figure 5.1: Conclusion – Costs and benefits of the AMI Program

		AMI Program 2008-28 (NPV at 2008)	Continuing the AMI Program from 2012 (NPV at 2012)	Slowing the pace from 2012 (NPV at 2012)
Total costs	<i>in \$m</i>	2,349	1,572	1,394
Total benefits	<i>in \$m</i>	2,030	2,285	1,736
Net	<i>in \$m</i>	-319	713	343

Figure 5.2 demonstrates the profile of costs and benefits over 2008-28 under the 'Continuing the AMI Program' and 'Slowing the pace' scenarios.

Figure 5.2: Scenarios from 2012 – Profile of costs and benefits



6. Enhancing the benefits of the AMI Program

6.1 Introduction

The third element of our analysis involved the identification of potential modifications to the AMI Program that could maximise and bring forward net benefits to customers. Given our finding that the total AMI Program will result in net costs to customers of \$319 million (NPV at 2008), should the Government decide to continue the AMI Program, modifications to enhance and bring forward the benefits are needed to improve the impact of AMI on Victorian electricity customers.

As discussed above, in calculating the benefits of the AMI Program for Victorian electricity customers, we have assumed a number of steps to improve the AMI Program are undertaken in the latter half of 2011. We have also assumed that the Victorian Government's current study on the RF emissions of smart meters finds no material detrimental health impacts.

In addition, in undertaking our cost benefit analysis a number of further options to modify and improve the AMI Program have been identified. The impacts of these additional options on the costs and benefits of the AMI Program have not been included in our cost benefit analysis.

Further detailed analysis of the identified modifications is the subject of a separate phase of our review, within Work Stream 2.

6.2 Assumed steps taken to modify and enhance the AMI Program from late 2011

6.2.1 Customer engagement program

As detailed in section 4.4.5 our analysis of the AMI Program benefits assumes that from late 2011, the Victorian Government leads a significant and sustained customer engagement program, similar to that undertaken by HydroOne in Ottawa, Canada. Without customer engagement, we consider that significant AMI benefits are at risk. As part of Work Stream 2, we will further develop and quantify an appropriate customer engagement program for the Government to consider implementing.

Options for implementation of customer engagement

We identified three separate issues that need to be targeted through customer engagement:

1. Smart meter safety
2. General network and energy efficiency and other non-tariff related benefits of the AMI Program
3. Innovative tariffs and demand management benefits of the AMI Program.

In our view, if customer engagement on items 1 and 2 above is not undertaken, all benefits associated with the AMI Program are at risk. In addition, there is significant risk that the AMI Program costs will increase as AMI meter refusal rates grow and customers request that their AMI meters be removed. We anticipate additional costs

in the order of \$100 per customer where AMI meters are removed and replaced with accumulation meters, excluding the cost of the new accumulation meter.⁶⁷

However, in our view, customer engagement regarding item 3 above (innovative tariffs and demand management) may not necessarily be the Victorian Government's responsibility. Should distributors or retailers decide to offer TOU tariffs, critical peak incentives or direct load control contracts on a voluntary basis (as we have assumed no mandatory tariffs), responsibility for customer engagement in these voluntary tariffs and contracts will be undertaken by the market.

In our view, the Victorian Government has two options for addressing issues 1 and 2 above:

- a. Undertake a program to address smart meter safety concerns and highlight the general network and energy efficiency benefits of the AMI Program. This approach could be carried out at a low cost to Government, with the expectation that once Government has expressed a clear opinion and objective on these issues supported by credible scientific evidence, customer engagement could be further implemented by other stakeholders (retailers, distributors and other market participants).
- b. Develop a highly involved information program to actively engage the public in the RF radiation debate and other emerging customer safety issues related to the AMI program, providing the facts in a campaign including advertising, media involvement and community events. A similar program was undertaken by San Francisco utility PG&E in response to the emergence of community concerns regarding RF radiation, at an estimated cost of US\$70 million.⁶⁸

6.2.2 Removing barriers to remote connections and disconnections

One of the core functionalities of AMI is the ability to remotely energise and de-energise (referred to in this report as connect and disconnect) customer premises, rather than sending out a field services officer to perform the task manually. As discussed above in sections 4.6.2.2, despite 27% of Victorian customers having installed AMI meters in June 2011, this remote service is not yet being provided.

Discussions with retailers and distributors have highlighted a disagreement between them regarding the process to be undertaken by retailers in checking whether a premise is safe to de-energise or re-energise. We understand that there is an issue regarding which party (distributor or retailer) is liable in the event of an unsafe disconnection (for example, switching off customers on life support) or connection (for example, where a property is unsafe to re-energise and a fire is caused). There are mixed expectations among stakeholders on the ability of this to be resolved quickly. We understand that Energy Safe Victoria and DPI are involved in the discussions on this issue.

We recommend that Government act to resolve the liability issues preventing remote connections and disconnections, via either a regulatory change or the development of a retailer-distributor interface process manual. Enabling remote services provided via the AMI meters will allow customers to experience the benefits of AMI, and contribute to their engagement with the AMI Program.

⁶⁷ This reflects the cost of an electrician removing the AMI meter on request, disabling the communications in the meter and adding it to the distributor's inventory, before updating customer information in the distributor's systems.

⁶⁸ The actual cost of this community engagement program is to be the subject of a September 2011 proposal by PG&E to the CPUC. Once this proposal is submitted, more information on the costs of the PG&E customer engagement program will be available.

Our analysis of the benefits of the AMI Program has assumed that this barrier is removed by the start of 2012. As part of Work Stream 2 we will develop and propose a framework for addressing this barrier.

6.2.3 Developing a process framework for connection of IHDs to AMI meters

Discussions with retailers have revealed another area where retailer-distributor interface issues are creating barriers to customer realisation of AMI benefits. While the AMI Home Area Network technology is designed to easily connect to IHDs and other devices, the processes relating to the connection of devices has not yet been established in Victoria.

Retailers have highlighted that distributors are not required by the AMI OIC and AMI Minimum functionality specifications to facilitate the connection of IHDs. Given this, there is currently no established process for connection of devices, which would require some communication between distributors and retailers, and retailers are unable to offer IHDs to their customers.

We recommend that Government consult with the distributors and retailers to develop this process and facilitate the connection of IHDs to the AMI meters. Again, removing this barrier will allow customers to experience the benefits of AMI, and contribute to their engagement with the AMI Program.

Our analysis of the benefits of the AMI Program has assumed that this barrier is removed by the start of 2012. As part of Work Stream 2, we will consult with the relevant stakeholders and develop an appropriate framework based on the Victorian technology, and advise on its implementation. Preliminary discussions with retailers have revealed that the processes they have proposed for connection of IHDs are similar to those proposed by market participants in Texas, Pennsylvania and New Jersey. This relevant international experience will be drawn upon in finalising a Victorian-specific solution as part of Work Stream 2.

6.3 Further options to modify and enhance the AMI Program

6.3.1 Improve AMI Program governance

One of the key findings of the VAGO review was that 'Governance of the AMI project has not been commensurate with the significance of the market intervention and its direct ramifications for consumers.'⁶⁹ Our stakeholder consultation process supports this finding.

We recommend that Government act to improve the current management of the AMI Program, by revising the structure of its management and re-engaging consultation among stakeholders. Further process, communication and technical barriers to the realisation of benefits (such as those outlined above) could be prevented by revising AMI Program governance.

As part of Work Stream 2, we propose to review the AMI Program governance, and identify necessary amendments to establish an appropriate framework that meets the best practice benchmarks necessary for a program of the scale and scope of the AMI rollout. We will draw from vast international experience in infrastructure and program management.

⁶⁹ Victorian Auditor General (2009) 'Towards a 'smart grid' – the roll-out of Advanced Metering Infrastructure', p. 9.

6.3.2 Encourage the deployment of IHDs

IHDs offer customers a tangible benefit of smart metering that has the potential to improve energy efficiency, enable innovative retail market services, and better enable the introduction of TOU tariffs, critical peak incentives and direct load control.

Encouraging the deployment of IHDs via either direct subsidy, or through another Government energy efficiency program (such as the Victorian Energy Efficiency Target, VEET) would rapidly improve customer engagement with the AMI Program, and help to enhance the benefits of AMI.

As part of Work Stream 2, we will develop options for the appropriate distribution of IHDs to Victorian customers. It is our view that, given the various technological choices and range of available devices and mechanisms to provide in-home energy consumption information, it would not be appropriate to mandate a particular technology, rather it is important to give the market and customers choices.

6.3.3 Revise the AMI OIC to reduce 2012-15 costs

We have identified some areas where the distributors' proposed 2012-15 AMI Program costs are higher than efficient benchmark costs. As discussed in section 4.4.6, of these we have identified approximately \$40 million of proposed costs which we consider are unlikely to be rejected by the AER (and are therefore included in our total AMI Program cost assessment). Amending the cost recovery framework in the AMI OIC to enable more rigorous cost benchmarking assessment by the AER could reduce the AMI Program costs.

In addition, reducing or removing the ability for actual costs above the Approved Budget to be passed through to customers without review could also potentially reduce the costs incurred by customers over 2012-15. This is discussed further in section 4.8.2 .

It is noted that the costs of amending the AMI cost recovery framework (including legal and administrative costs) would need to be fully understood and compared against the potential impact the changes would have on AMI Program costs.

6.3.4 Amend the rollout timeframe requirements to avoid most costly areas

International experience of smart meter rollouts suggests that the most expensive and difficult areas to install and remotely connect are left to the final stages, and the costs associated with connecting them are often (a) well above those for other areas, and (b) significantly underestimated by utilities.

As the distributors prepared their 2012-15 AMI proposals, less than 20% of AMI meters had been installed, and less than 5% of these were remotely communicating.⁷⁰ To date, very few meters have been installed in the most difficult areas of Victoria to serve (where physical barriers such as mountains and long distances between meters and collectors cause problems for the communications network). In most of these difficult areas, the wireless communications networks have not yet been established. We note that some distributors are proposing to use alternative communications technologies (such as 3G) as 'in-fill' to support their mesh radio or WiMax networks for these areas.

⁷⁰ AMI Deployment Dashboard, January 2011.

While it is now clear that the costs of implementing and operating separate communications technology for a small number of customers in rural areas will not be insignificant, given international experience, it may be that the full costs of rolling out AMI to these customers is still uncertain.

The AMI OIC requires that by 31 December 2013, the distributors roll out remotely read interval meters to, as far as practicable, 100% of Victorian customers. This requirement could be eased by either reducing the required percentage coverage, or providing a longer time period to connect the most difficult areas (by which time lower cost solutions may be available). While these options will also eliminate some benefits, the benefits lost may be significantly outweighed by the costs avoided.

We recommend analysis of the costs and benefits of lowering the requirement to roll out meters to 100% of customers by 2013.

Appendix A: Detailed assumptions

Discount rate	8%. This a real pre-tax rate, broadly consistent with the WACC parameters applied by the AER for the Victorian distributors over 2011-15.
Metering capex asset life	15 years. This is consistent with the assumptions in the AMI OIC. Note that sensitivity analysis of this assumption is provided in section 4.9.
IT capex asset life	7 years. This is consistent with the assumptions in the AMI OIC.
Victorian Pool Prices data	Based on actual data from 2008 to 2010. Forecasts based on ACIL Tasman, <i>Energy market modelling – expansion of the ESI scheme</i> , 21 February 2011. Report prepared for The Department of Primary Industries, Victoria.
Value of customer reliability	Sourced from report: Oakley Greenwood, <i>Valuing Reliability in the National Electricity Market - Final Report</i> , March 2011
Customers annually requesting special read, disconnection (de-energisation) and re-connection (energisation)	22% of total customers.
Average SAIDI 2003-08	Based on total actual 2003 to 2008 total SAIDI (adjusted for extreme values). Source: AER, Victorian Electricity Distribution Businesses Comparative Performance Report 2008, Nov 2009.
Cost of special meter reading, manual energisation & de energisation	Charges based on AER Victorian Distribution Determination 2011-15. On average special reading plus manual de-energisation charge of \$32.30, with manual re energisation charge of \$18.73.
Cost of special manual read after hours	Charges based on AER Victorian Distribution Determination 2011-15. On average \$76.7
Avoided augmentation cost	\$200,000/MW/year. This represents the annual cost of OCGT plus avoided network augmentation.
Same day connection	160,000 customers

request not completed	
Customer number growth rate	1.6% on average
Average energy growth rate	0.7%. Source: ESOO 2008 (low case)
Victorian peak demand	9,818 MW based on 2008 data. Domestic customers account for 41% of total demand
Victorian Net System Load Profile	17,746 GWh. Based on 2008 data.
Average cost of IHD	\$125. Based on market knowledge.
Average cost of installing DLC device	\$75. Based on market knowledge.
TOU take up rate and peak reduction	4% commencing 2014, reaching 15% by 2017. Peak reduction of 1.5% (based on benchmarks and market knowledge).
CPI take up rate and peak reduction	5% commencing 2014, reaching 33% by 2020. Peak reduction of 15% (based on benchmarks and market knowledge).
DLC take up rate and peak reduction	1% commencing 2014, reaching 25% by 2020. Peak reduction of 15% (based on benchmarks and market knowledge).
Take up rate of IHD and energy reduction forecast	1% commencing 2014, reaching 25% by 2020. Energy reduction of 1% reaching 6% by 2022 (based on benchmarks and market knowledge).

Appendix B: Key reports

1. "Who benefits from AMI?" A report by Doug Houseman.
2. "Smart Metering: Lessons Learned" A report by Doug Houseman for the Electric Power Research Institute (EPRI)

Doug Houseman was a key member of the Deloitte-WorleyParsons team and provided significant technical and international expertise on AMI and the deployment of smart meters.

Statement of responsibility

This report: Advanced metering infrastructure cost benefit analysis (Final report) was prepared for the Department of Treasury and Finance (DTF) solely for the purposes of assisting the DTF to make an assessment of the costs and benefits of the mandated rollout of advanced metering infrastructure.

In preparing this report we have relied on the accuracy and completeness of the information provided to us by DTF, DPI, consumer representative organisations, electricity distribution businesses, electricity retail businesses and from publicly available sources. We have not audited or otherwise verified the accuracy or completeness of the information. We have not contemplated the requirements or circumstances of anyone other than DTF.

The information contained in this report is general in nature and is not intended to be applied to anyone's particular circumstances. This report may not be sufficient or appropriate for your purposes. It may not address or reflect matters in which you may be interested or which may be material to you.

Events may have occurred since we prepared this report which may impact on it and its conclusions.

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WHO BENEFITS FROM AMI?

By Doug Houseman

In today's world, the question of smart metering is no longer one of will it happen, but is more one of when will it happen and who will pay for it?

As the utility value chain continues to be pulled apart into pieces around the world, the answer to the “who” will pay gets more complex. In the traditional ownership model, all the utility functions had a single owner and so benefits that crossed multiple business segments (e.g. distribution, transmission, generation for electricity) could be paid for by the single owner of the utility. Today with the European Union unbundling their utilities and other utilities splitting into separate companies, as well as new companies building facilities that are not owned by the traditional utility, the question has a much more complex answer. In the end of course the customer will ultimately pay the cost – they always do. But, along the way, where will the costs be allocated and who will have to dig deep into their own pockets to pay for the system, until the customer eventually pays that cost back? How much of the cost has to come from internal savings? How much of the cost is considered new capital or new operations and maintenance (O&M)? New costs are typically passed directly on to the customer. These debates are going on in many regulatory bodies today. It is not an easy question to answer and no two regulatory bodies have given the same answer yet.

One of the issues that has had little open discussion is – Who benefits? It only makes sense to look at the parties that benefit when allocating the cost of the system. The discussion always seems to boil down quickly to one or two parties and the benefits they get from the implementation of smart metering. While this is a good discussion to have, it has its pitfalls. The first pitfall is that if one party is going to pay the whole cost, they may choose a less costly system with fewer benefits for the whole value chain, than if everyone either shared the costs together or the costs were allocated such that the installing party got paid directly by the customer for the other benefits that hopefully they will ultimately benefit from. The second pitfall is that if too much cost savings is pushed at the installing party, they may choose to stall the installation as long as possible or they may end up with an incomplete system that does not really get all the benefits – the meters are installed, but the systems and staffing to support the operations may get short changed.

Smart metering has a large number of components and each of those components generates value and costs (Figure 1).

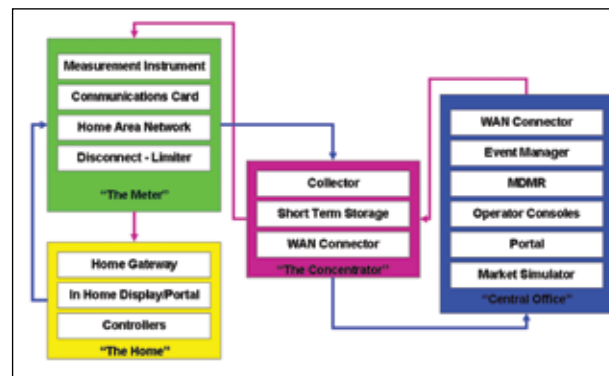


Figure 1 - Major smart meter system components

Most implementations initially focus on the end point and its capabilities to make the system run. This is a useful way to do things in a system where timing of information is not important. In the systems where the timing of information is important, the network components are equally important to focus on. In Figure 1 four main components are shown: the meter, the home, the concentrator, and the central office. Determining which benefits the system will deliver will have a large impact on the first three and very little impact on the central office. So determining the benefits delivered early in the process and using that as a starting point for selections for the meter, home and concentrator is a very useful way to start. If the distribution company is responsible for the deployment and they are asked to find deep cost savings to fund the project, they will probably focus on benefits that will help them make the cost savings and ignore the rest of the benefits, unless they are forced to add them to the system by the regulator. This is an unfair position to put the distribution company in and it ends up in a system that does not provide the highest value to the customer or any other part of the value chain. Remember that integration into the systems in the central office will have to be done in order for any of the benefits to be realised.

CATEGORISATION OF BENEFITS

In Table 1, there is a categorisation of benefits and who benefits from them. There is no attempt to put a value on the benefits, because the business cases vary widely from country to country. Rather this table attempts only to allocate benefits to each part of the value chain. Many will argue that the allocation to the customers is too small and that the allocation to the regulator is too large. The criteria for allocating a benefit to the customer was that the average customer in this class would see a direct cost reduction on their bill; while they will see a benefit in an indirect fashion from almost everything listed, the ones allocated to them show a direct cost reduction to the AVERAGE customer. For the regulator, the allocation was made if the regulator would be able to better regulate the market and have better information available to manage the regulatory process. One area that the table is incomplete is in filling in the value chain for the gas and water benefits. Since the value chain is an electric one, it was not useful to complete the water and gas benefits that did not apply to electricity, but it would not be hard to transform the table to support water or a gas implementations.

The table is really four tables in one. The first set of columns in the table shows what equipment would have to be deployed to gain the benefit. The “x” is in the first column that would support the benefit, so if a “dumb meter” is marked for a benefit, the “billing” and the “operational” meter would both support the benefit as well. The “e” in a meter column indicates that that is the minimum class of meter that would be required

to support the other equipment installed and enable that benefit, and that the benefit is delivered by the item on that line that has the “x” working through the meter with the “e” in its column on that row. The reason for doing this is that in some markets the meter for that function may be replaced with a different box (e.g. France’s energy box).

The second section of the table is the value chain and the columns cover all

Benefit	Equipment						Recipient of Benefit														Utility								
	Dumb meter	Billing meter system	Operational metering system	Disconnect switch	Demand response	Home area network	Distribution	Transmission owner	ISO/RTO/TSO	Conventional generation	Renewable generation	Billing/customer service	Energy retailer	Trading	Regulator	Government	Residential customer	Commercial customer	Industrial customer	Environment	Emergency services	Third party service providers	Energy efficiency	Reliability	Electric	Gas	Water		
Metering																													
Meter reading	X	X	X				X				X	X																	
Non-technical losses		X	X				X		X		X	X				X	X	X	X										
Net metering	X	X	X				X	X		X	X	X	X	X	X	X	X	X	X	X		X							
Real-time customer information		e	e			X						X			X	X	X	X				X	X						
Operations																													
Connectivity validation			X				X																						
Closing verification			X				X																	X	Y	*	*		
Geo-location			X				X																			Y	Y	Y	
Power quality monitoring			X				X	X	X								X	X	X				X		Y	N	N		
Asset load monitoring			X				X	X																X	Y	Y	Y		
Phase balancing			X				X	X									X	X	X				X	X	Y	N	N		
Load balancing			X				X	X	X														X	X	Y	Y	Y		
Work dispatch improvement			X				X															X		X	Y	Y	Y		
Order completion automation			X				X																		Y	Y	Y		
Site/line status			X				X														X		X	Y	*	*			
Automation of emergency response			e	X			X								X						X		X	Y	Y	Y			
Call centre unloading			X				X				X	X													Y	*	*		
Restoration verification			X				X																	X	Y	*	*		
Vegetation management		X	X				X																X	X	Y	N	N		
Distribution SCADA			X				X	X															X	X	Y	Y	Y		
System security			X				X	X							X						X		X	Y	Y	Y			
System protection				X	X	X	X	X	X	X														X	Y	Y	Y		
Selective load management				X	X		X	X	X	X				X										X	Y	*	N		
Outage notification			X				X				X						X	X	X					X	Y	Y	Y		
IEEE outage indices		X	X				X								X										Y	N	N		
Islanding verification for DG			X				X			X														X	Y	N	N		
Distributed capacitor bank management			X				X	X	X															X	Y	N	N		
Field worker data access			X				X															X		X	Y	Y	Y		
Regulatory																													
Tariff design		X	X				X	X	X		X			X												Y	Y	Y	
Rate case support		X	X				X	X	X		X			X												Y	Y	Y	
Critical and complex tariff design		X	X				X	X	X		X			X												Y	Y	Y	
Cross subsidisation		X	X								X	X		X												Y	Y	Y	
Investment decision support		X	X				X	X	X	X	X			X												Y	Y	Y	
Customer segmentation		X	X								X	X	X	X												Y	Y	Y	
Customer operations																													
Prepayment		X	X								X	X			X	X										Y	Y	Y	
Real time pricing			X					X			X		X	X					X				X		Y	Y	Y		
Time of use pricing		X	X					X			X		X	X					X				X		Y	Y	Y		
Critical peak pricing		X	X					X			X		X	X					X				X		Y	Y	Y		
Bill - paycheck matching		X	X								X						X								Y	Y	Y		
Remote disconnect			X	X			X				X										X				Y	Y	Y		
Customer price display			X			X		X							X	X			X						Y	Y	Y		
Remote issue validation			X								X					X	X	X							Y	Y	Y		
Customer dispute management			X								X	X		X		X	X	X							Y	Y	Y		
Outbound customer issue notification			X				X				X	X				X	X	X							Y	Y	Y		
Customer advisory		X					X										X	X				X	X		Y	Y	Y		

Benefit	Equipment						Recipient of Benefit														Utility							
	Dumb meter	Billing meter system	Operational metering system	Disconnect switch	Demand response	Home area network	Distribution	Transmission owner	ISO/RTO/TSO	Conventional generation	Renewable generation	Billing/customer service	Energy retailer	Trading	Regulator	Government	Residential customer	Commercial customer	Industrial customer	Environment	Emergency services	Third party service providers	Energy efficiency	Reliability	Electric	Gas	Water	
Forecasting and scheduling																												
Demand side management			e		X	X	X		X	X	X	X	X	X	X					X			X	X	Y	Y	Y	Y
Load forecasting		X	X				X	X	X	X		X	X										X	X	Y	Y	Y	Y
Simulation		X	X				X	X	X	X	X	X	X	X	X					X			X	X	Y	Y	Y	Y
Asset load analysis		X	X				X	X	X	X	X		X										X	X	Y	Y	Y	Y
Load scheduling		X	X				X		X	X	X	X	X					X	X	X			X	X	Y	Y	Y	Y
Curtailed planning		X	X				X		X	X		X	X	X	X					X			X	X	Y	Y	Y	Y
Planned outage scheduling		X	X				X	X	X	X	X												X	X	Y	Y	Y	Y
Direct load control					X	X	X		X	X	X	X	X		X					X			X	X	Y	Y	Y	Y
Construction and standards																												
Design standards		X	X				X	X		X	X				X	X					X			X	Y	Y	Y	Y
Maintenance standards		X	X				X	X		X	X				X									X	Y	Y	Y	Y
Feeder ratings			X				X																	X	Y	N	N	N
Rebuild cycle		X	X				X	X							X									X	Y	Y	Y	Y
Replacement planning		X	X				X	X		X					X									X	Y	Y	Y	Y
Distributed resources integration																												
Net and gross generation monitoring		X	X							X	X	X	X	X	X	X					X		X	Y	N	N	N	N
Storage fill/draw management			e			X	X		X	X		X	X							X			X	X	Y	*	*	*
Plug in hybrid management			e			X	X		X	X	X	X	X	X	X	X	X	X	X	X	X		X	X	Y	N	N	N
Supply following tariffs			X							X		X	X	X	X					X			X	X	Y	N	N	N
Small fossil source management			e			X	X		X			X												X	Y	Y	Y	Y
Gas and water																												
Leak detection			X																					X	N	Y	Y	Y
Battery management			X																						N	Y	Y	Y
Flood prevention			e	X																				X	N	N	Y	Y
Gas leak isolation			e	X																				X	N	Y	N	N
Pressure management			e	X	X	X																	X	X	N	Y	Y	Y
Other																												
Appliance monitoring			e			X											X	X					X	X	Y	Y	Y	Y
Home security monitoring			e			X											X	X					X		Y	Y	Y	Y
Home control gateway			e			X					X	X					X	X					X		Y	Y	Y	Y
Medical equipment monitoring			e			X	X									X	X				X	X		Y	Y	Y	Y	Y
Benefit count							48	21	26	17	15	17	24	12	22	16	14	12	10	16	4	6	17	34				

the pieces of the electric value chain. Again it would not take much work to transform this table for gas or for water. All of the columns where the benefits should be allocated are marked for each benefit. Again there is no attempt to assign value to the “x” in the columns or to assign a percentage of the “x” to a specific column. This is a complex process that has to be done on a project by project basis. The table is valid for everyone because it does not attempt to assign values, only to show the allocations. At the bottom of each column in this section is a count by the column, which can be used as a discussion started from the percentage of the allocations that belong to a participant in the overall market that the project is being done in. For instance the Transmission owner sees 21 of 280 allocated benefits or approximately 7.5 percent. Does that mean they should bear 7.5 percent of the costs? No, it does not, but they should bear a portion of the costs and as a starting point for a discussion, 7.5 percent is not a bad place to start. This will force then into the discussion and into helping quantify the benefits they see. The same can be said for every participant in the

market. The goal of this part of the table is to help identify who is the rightful beneficiary and help to make it clear why some benefits make it into rate cases and others do not, and why some parties who are the deployment owners will focus on some benefits and others on different benefits.

The third portion of the table looks at which benefits help with energy efficiency and which with system reliability. This is a discussion that many regulators and utility struggle to have as they start down the path of installing the system for one overarching goal and then have to try to determine if the other benefits can be placed within that goal or the programme focus has to be expanded to cover the additional benefits that the customers can gain from the system.

The final portion of the table (the last 3 columns) covers which benefits would be gained by independent installations (e.g. gas only) of smart metering. The table was created with electricity at its core, so this portion helps to weed out some of the benefits that do not apply to water and gas. The “*” in the column means that pressure transducers or flow

sensors would be required to implement this in a water or gas environment. Meters with these types of sensors are not the norm today and so most implementations will probably forego these benefits, since the costs of the meter rise rapidly when these components are discussed. In some cases though, the benefits listed with the asterisk can be realised from the strategic deployment of very small numbers of meters with these advanced capabilities.

To create a discussion document for a specific project, the easy way would be to remove the rows that contain benefits that are not being discussed and then count the benefits at the bottom of the table for the remaining rows. That should help focus the "who benefits?" discussion and also help to determine who the stakeholders are. In all too many cases many of the stakeholders will choose to sit on the sidelines and let someone else do the job, so long as they can eventually figure out how to get access to the benefits they want from the system. The problem is that as the implementation goes along, if the benefits were not planned for up front, it may be cost prohibitive to gain the benefits later, up to and including having to re-do the full installation.

One interesting way to look at a project is to remove the rows that are out of scope and see what portion of the benefits to each participant in the market will be delivered by the planned project. In general, if it is less than 60 percent there is a high probability that the project will never

be completed, since there will be enough missing value that the regulators will eventually have to step in again and re-open the discussion.

A word of caution is that, no matter how good the organisation is, it cannot absorb all the change that is created by attempting to gain all the benefits listed here in a short period of time, so once the value of the benefits is known, creating a timeline to implement the value is important. Normally with a three to five-year deployment of the meters, it will take five to seven years from the first meter install until most of the planned benefits are up and running, so the benefits that have the highest value should be prioritised with a partial installation of meters with the focus on gaining those benefits early in the project, then moving through the benefits over time to complete the harvesting of the benefits.

Supplemental materials are posted with the online version of this article on www.metering.com. These include extended definitions of the equipment and benefit recipients (columns) and the benefits (rows), and a downloadable version of the table, so you can remove the rows that do not apply to your project. ■

ABOUT THE AUTHOR: Doug Houseman is a 35-year veteran of the industry and a member of Capgemini's Global Utility practice.

ABOUT THE COMPANY: Capgemini is a global consulting company with annual revenues of more than 10 billion Euros. Capgemini's utility practice has more than 8,000 members and annual revenue of more than 2 billion Euros. Capgemini is ranked number one by Gartner for Utility consulting globally.

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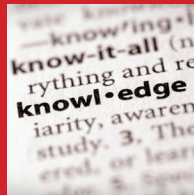
On site meter testing solutions

ZERA GmbH
Hauptstraße 392
D-53639 Königswinter
Germany

Telefon +49-2223-704-0
Fax +49-2223-704-70
Email info@zera.de
Website www.zera.de

Smart Metering: Lessons Learned

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Smart Metering: Lessons Learned

More than 50 utilities around the world have started implementations of Advanced Metering Infrastructure (AMI, or Smart Metering). Approximately 20 of those utilities have completed their implementation and many of the others are well down the road to completion. This paper provides lessons learned from more than 30 smart metering implementations, based on the direct experiences of utility smart metering project teams.

The lessons fall into the following categories:

- Time required for implementation
- Installation
- Meter functionality
- Communications networks
- Firmware and software
- Customer considerations
- Project team
- Operations
- Software integration
- Miscellaneous lessons

Time Required for Implementation

The biggest lesson learned is that of time. The average time of implementation, from placing the first production meter into service until the project covers 99% of its customers, is five full years. If the majority of meters are inside customer homes, an additional 12 months will be needed. Experience shows that covering the last 1% of customers can take up to an additional two years.

A recommendation based on successful projects is to plan approximately 10% installation in Year One, 22% in Year Two, 25% in Years Three and Four, and 17% in Year Five, for a total of 99% installation.

Installation Lessons Learned

Lesson 1: Know the factors that influence installation rates. The number of ANSI meters that can be installed each day by a single installer varies greatly: from 15 to 65. In general, a team of installers will average around 30 to 40 meters a day. The following key factors influence installation rates:

- Customer density. The higher the density, the more meters the team can install each day.
- Density of fences and pets. More fences and more pets means fewer installed meters per installer per day.

- Age of housing stock. Homes that are older than 50 years have a higher rate of bad meter sockets and other issues, and this results in more unable to complete (UTC/UTI) than newer homes.
- Installer training. The better the training, the faster the meters can be installed.
- Portable toolset. The leaner the toolset the installer carries, the faster the meters go into sockets (lower carry weight, fewer return trips to the vehicle for more meters). Small wagons or 5 gallon buckets for meters are also helpful in reducing trips back to the vehicle.
- Software for handheld devices. Ease of use for the software in handhelds is critical to the speed of installation. The more information that can be pre-programmed and just confirmed by the installer, the faster the installations will go. Use of GPS and/or photos at the site do not add to the installation time significantly if the installer is well trained. Bar codes do reduce the time significantly for data entry.
- Door bell policy. If you have your installers ring the bell prior to installation to give home owners time to shut down computers and other equipment, as well as door hang after meter installation, this will decrease the number of meter installations per day.
- Clustering meters for a single installer to minimize distance between installations improves productivity. Meter routes do this already in most cases for the meter readers. Use of meter routes for installation can enhance productivity.
- Installers should ideally have 150-200% of the work they are expected to finish loaded in their handhelds and enough installation materials to support all the work loaded.

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This white paper was prepared by Doug Houseman, Enemex Corporation



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These are the largest drivers in installation rates. In a normal suburban neighborhood, without ringing the doorbell or door hanging, an average installer will install 45-50 meters in an average eight-hour working day.

Lesson 2: Use the right tools. The tools an installer carries are important to the success rate of installs.

- Bees, wasps, hornets, dogs, and other animals all impede the installation rate. The right insecticides and deterrents are critical to installation speed. Ensuring that any liquids are not flammable and are not conductive are important to the safety of the installer and structures.
- Most digital meters can be damaged by sharp blows during installation. Removal of rubber mallets and other tools that can be used in that manner reduces the number of failed meters in the field. A proper meter puller is a much better choice.
- Installers have a tendency to add tools to their tool set over time. It is important to inventory tool sets, replacing worn or damaged tools, and removing extras that have been added.

Lesson 3: Customer courtesy. Customers tend to keep appointments for inside installation if (1) they can be given a 30-minute window for the installation and (2) are kept informed as to when the installer will arrive. The larger the appointment window, the lower the odds of having someone available to let the installer in. As a solution, give installers who need to enter a home a mobile phone and phone numbers for their shift, and this will help to keep customers better informed. Train installers how to tell customers about arrivals, delays and cancellations, and this will help customers feel more comfortable about their installer. When installers wear uniforms and badges, customers feel more comfortable.

The installers are the face of the company and may be the last company face that the customer ever sees, given that meters will now report automatically. It is important that installer uniforms be neat, clean and presentable. It is also important that the installers know how to talk with the customer.

Meter Lessons

Functional requirements. The first lesson a company learns about smart meters is that they have a lot of options and functions. In many cases, the decision is to pay for only the minimum functions needed to complete the business case. This may or may not be a sound decision in the long run. Working through the actual

needs for data across the whole organization can determine, better than the typical business case, what features meters need and more importantly, how many of the meters need the features. Business units should be involved early in the smart meter project. Business units that are not sufficiently informed of the status of the project or provided with the ability to give feedback will take longer to adopt and use smart meter data.

In many cases, a small number of strategically placed meters may be needed for real-time operations, providing voltage and other feedback to the control center. There is no reason for every meter to have exactly the same features, even if they are all going on residential locations. Designating a small percentage of meters as operational, or bellwether meters, can help keep data and communications needs in check while providing vital information on the state of the distribution grid. In a typical circuit with 10,000 customers, the installation of 20 bellwether meters can typically give the control room all the necessary information on the status of the circuit from an operational standpoint. These bellwethers can be higher end meters and may even be tied to the communications network in a different way than the other 9,980 meters.

Separation of operational requirements from customer requirements can clarify what a meter needs to do and help improve both the operations capability and the overall cost of a project. Thinking through what data will eventually be required, and the latency on that data, should be done prior to selecting meters for deployment.

Meters have three critical components that deserve consideration during a purchase decision. The first are the sensors—what can the meter measure? The second is the processor—how much data and firmware can the processor handle in what time period? The processor used to not be important, but with increasing security requirements and the need to encrypt and decrypt most data, the processor horsepower now is important. The vendor can choose to do one of two things with regard to security processing: (a) put a special processor on the meter that only handles security or (b) upgrade the processor on the meter to handle security processing for the next 20 years. Realize that doubling the length of the security key for an encryption algorithm can increase the processing time by a factor of four or more, so test the processing time for long keys with the vendor prior to accepting the device as being ready for deployment. NIST has published a set of guidelines on key length for the next 30 years, so the length of key to test is readily available.



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The third critical component to consider is firmware or “code” space in the device. Assuming there is one unit of firmware in the meter today, encryption and decryption will require three units of space for that firmware (running image, encrypted image and decrypted image). In looking at the growth in firmware in factory equipment over a 10 to 15 year life, the amount of firmware to do the same job about doubles (due to fixes to original code, improvements in error handling, etc.). So one unit would be two with fixes, and to handle security the device would need six units of code space. Given that the industry does not know all the uses for the devices in the future, it is reasonable to expect that the original firmware will grow in size to support new features. For argument’s sake, let that be one additional unit of firmware. That means a minimum of three units (original, fixes and additional functions) is needed for a running image and a total of nine units to handle security. Any device with less than this is potentially a problem for future upgradability and security.

An emerging question is how much pre- and post-processing for Home Area Networks would be done in the meter. This is beyond any discussion of lessons learned but it is a question that bears watching.

Communication Network Lessons Learned

Vendors optimize their plans for meter communications networks. In a perfect world, those plans would work correctly out of the box. In the real world, more network equipment will be required than planned. Initial success based on vendor-suggested equipment and single day for retrieval of information is typically in the 84-85% range.

Tuning smart meter networks is critical to their success. The need to move or add relays, collectors and other equipment to the network should be anticipated. Approximately 30% of collectors and relays will eventually have to be moved to achieve better network performance. It is not unusual to have to add 30-50% more collectors or relays to a network over time to improve single period collection rates. Over a period of 12-18 months, network tuning can raise single period success from 84-85% to 95-97%.

One of the problems with tuning a network is that seasons may play a large role in determining the proper location of collectors achieving high success rates. In the fall and winter, when most trees are bare of leaves, one collector position for an RF network might work quite well. In the early spring, however, when those same trees have new leaves full of sap, the same collector might not work at all for

relaying information. Knowing this, and keeping an eye on vegetation conditions in an area, can be used as an early warning for some problems that may occur in a system.

Another issue might be trash day. Movement of metal trashcans can impact collection of data. Still another can be hunting season. It is not unusual in some areas to find equipment used for target practice prior to or during hunting seasons. Each utility that has deployed an RF-based system has found reasons for communication failures that are unavoidable. Being ready with a crew and a spare relay during hunting season can make all the difference in collection statistics for that area.

Almost no one takes into account that not every device will provide perfect information on the first try, so there is a tendency to size networks based on a perfect communication. In reality, the devices that do not respond tend to generate more network traffic, while devices that generate imperfect messages generate still more. Taking into account re-tries on missing devices, as well as devices with garbled messages in the design of the network, is useful to determine the actual traffic volume the network will see. Typically, networks see approximately 50% more traffic than the perfect network would. Also, firmware updates need to go out on the network and the traffic model for firmware updates should also be investigated for network sizing. In several instances, the firmware downloaded determined the final size of the network. The number and types of devices and the growth in their firmware must be considered in the sizing of the network.

Firmware and Software Lessons Learned

If meters and other devices are to have a long life they will need to have their firmware updated. Early in a project, when initial trials are underway, updates might happen weekly or maybe monthly, depending on the changes needed to meet the requirements of the deployment and whether the mating of the meter and the communications system is being done for the first time or not. As time goes on, the updates drop off in frequency to once a month, then a quarter, and then maybe annually. These updates are critical, if they cannot be performed successfully, the meters will have to be visited for manual updates. In any deployment a few meters will not take firmware and will have to be visited. Normally that number is measured in hundredths or thousandths of a percent. But sometimes the problem can be a lot larger.

To minimize this risk a small test bed should be built and maintained for the life of the deployment. This test bed should contain at least two or three units of each type of meter deployed and be located where it is easy to visit the meters when they need to be changed. It will not be unusual for a newly deployed meter to incorporate an older version of firmware. Knowing that the system can automatically recognize that fact and flag it is useful; knowing that the firmware will successfully install remotely is priceless. Occasionally the firmware might be more than one version behind. Being able to reload firmware in the test bed and perform updates that skip one or more versions is a good reason to have the test bed in a readily accessible location.

Another reason to maintain a test bed is performing software updates to the head-end, which contains the machine-to-machine communication protocols. Knowing that updates will work with a small population of devices before being installed in production is important to the continuity of the project. Again, this should be part of a lifetime test bed for the project.

Customer Lessons Learned

Lesson 1: Approximately 80% of customers will be where they promise to be. Therefore, expect about a 20% drop out on customer appointments. The wider the appointment window (e.g. 4 hours vs. 30 minutes), the higher the missed appointment rate.

Lesson 2: Customers want to see installers operating in the daylight, even when they prefer evening appointments. To accommodate customer preferences, group inside appointments for the long spring days if possible, and offer weekend appointments for inside meters. Customers don't want to stay home from work to have their meter changed.

Lesson 3: If a customer is going to tamper with a meter, 75-80% of the time the tampering will occur within 72 hours of installation. If tampering is a key component of the business case, installing the network before the meters will help find most instances of tampering.

Lesson 4: Customers will steal whole meters. Without a network to hear the loss of power or tamper messages, the meters might be missing for weeks before the theft is discovered. There is a web site that tells people how to remove the electronics and communications parts of a meter and leave only the base of the meter in place. That base will allow power to continue to flow, but cannot measure the power flow or report it.

Lesson 5: Keeping old meters for testing may be an important element in any regulatory proceeding on high bills. At a minimum, meter lots should be sampled when they come back from the field and the sampling results should be stored and cataloged. Also, photos of the final meter face and its readings are useful to have if there is a "final read" dispute. A fixture for taking high-quality pictures is easy to build and install. A good technician can easily photograph 200 meters an hour. This is a useful job for someone on light duty since it can be done inside a facility out of the weather and requires minimal mobility.

Lesson 6: A small percentage of customers will complain about trespass and destruction of property (e.g. cutting back a rose bush to access the meter). Equipping handhelds with cameras will allow installers to document the site prior to and after installation.

Lesson 7: Customers are, in general, happier when they know that the meter has been changed. They are even happier to have the installer knock on their door and give them a few minutes to turn off computers and other power-sensitive equipment. This adds to installation time and it also means that customers who were not home have a clear reason why the power "failed" during the day. If customer notification is important to your deployment, send a special letter two to four weeks prior to installation to alert customers about what is going to happen, with a post card reminder approximately a week prior to the actual installation.

Lesson 8: With better information and fewer estimated bills, calls to the call center actually drop, but during the installation period and the transition period between old and new bill formats, call volumes may increase.

Project Team Lessons Learned

Lesson 1: In a questionnaire sent to 35 utilities, project teams were asked what they would do differently if they had the project to do all over again. Listed below are the answers that were called out by more than half the respondents.

1. *Level of Outside Support.* Most indicated that they had attempted to do too much of the project without getting outside guidance or support. The issues ranged from public relations to communications design to project management to training. In every case, the respondents indicated that they probably should have engaged experts earlier.



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2. **Telecommunications Contracts.** Most of the respondents indicated that they structured the contract based on how they thought they were going to use the network and equipment. This turned out not to be the way they actually operated, and the contract either restricted what they wanted to do or added significant cost to the operation of the system.
3. **Use of GPS, RFID, barcodes and pictures during installation.** In most cases, respondents indicated that the lack of documentation from the field was a missed opportunity to improve recordkeeping or to document issues that developed later.
4. **Organizational Change Management.** Initially most organizations saw the smart metering project as a change in a limited area of the business with very little spillover into other areas and minimal impact on the business overall. In some organizations, however, the projects resulted in complete re-organization of the distribution or customer service groups. In every case the project added head count to the permanent organization, rather than reducing it.
5. **Network Ownership.** The question of why or why not to use a private network was in most cases not explored in a meaningful way, as it had a tendency to be an “emotional” issue rather than a technical issue with a business case.
6. **IT Integration Strategy.** This should encompass what to integrate, when to integrate and what volume of data to prepare for.
7. **Training.** The amount of training to develop and offer was underestimated on a regular basis.

These seven items were cited by more than 50% of the teams. In addition, field tool set, telecommunications model, communications latency from the field, business cases, capabilities of the meter, pilots, installation ramp-up rates, and meter disposal were common issues that teams mentioned, but did not reach the 50% threshold.

Operational Lessons Learned

Most of the utilities that start down the path of implementing smart meters don't even think about the implications of operating these meters. In many cases one of the perceived benefits of implementing smart meters is a reduction in head count. Nothing could be further from the truth. If smart meters are going to be the sensors of the grid or used for demand response, they require a 24/7 operations team.

Meters and their communications networks break, they need to be repaired and adjusted, and they need careful attention. If the latency of the data is critical, personnel may be required to work through the night.

There is far more work that has to be done from the meter head ends than is generally anticipated. In most cases a tremendous amount of IT effort is involved in making the process work. Often the effort involves a meter operator sitting on the head end sending commands.

Some smart meter communications vendors have a very limited built-in command set, so if an operator wants something different from the meter, they have to become an expert at the ANSI C-12.19 tables and how they are addressed in each meter deployed. It is not a trivial task to learn and be able to create the commands to support special queries. All of the vendors are working to increase their command sets, but out of the box many only have the command “tell me what you know” so the operators are in the loop for engineering information and meter queries.

Another problem is that some collectors do store and forward. They may or may not have the intelligence to forward information that is operations related (e.g. outage messages), which means setting up a query queue on the head end to poll head ends for outage or other information that is operationally important. The operations team has a lot of work to do to tune an out-of-the-box smart metering system to work the way they want it too.

Given that each 24/7 position takes five real people staff and the minimum staff in an operations center should probably be two people, then for smart meter operations, there is a need for a minimum of 10 highly skilled people to run the network and troubleshoot problems. This goes a long way to minimizing the head count reduction.

It takes up to two years after the system is fully installed before it is tuned and running well. During the five years of installation and two years of tuning, the operations team is going to learn many lessons, and it is critical that the lessons are documented and cataloged. In most cases the most difficult problem in year four or six is one that was solved in year one—but no one remembers the solution. Having a documentation specialist on staff for the full deployment to write and re-write procedures and lessons learned is critical to having good procedures when the deployment is done.



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A final recommendation regarding operations: It is highly useful to hire someone early and loan them to a utility with AMI experience for 60 days to work in operations. This employee will bring back priceless information that will help jump start operations processes. The preference is to use another utility using the same AMI system.

Operations, security and privacy are an evolving triangle. Being aware of the evolution and knowing that devices and networks require updates and improved security during their whole life cycle is an important lesson to internalize early. If the device has room to grow, most likely security will consume much of that room over the life of the device.

The operations team will become the core of the future smart grid operations center, and their capabilities and skills will influence the long-term success of smart metering and smart grid initiatives.

Integration Lessons Learned

Software integration is an area that is still evolving for smart metering, and there are many issues to consider.

1. Out of the box integration may not match that of other vendors. Only Multi-speak certification actually tests that the out of the box integration is really ready to go.
2. The IEC CIM model is an abstract model, which means someone will have to take it from abstract to a specification-ready to code. Expect that each end of each interface will take two to four weeks to create the specifications needed to write code.
3. Not all integration is create equal and neither is all data. Bulk data can be moved over slow interfaces with large flat files, with no need for fancy XML schemas. On the other hand, real time operations data may need to be moved quickly through highly tuned interfaces and at times even throttled to keep from overwhelming systems such as outage management systems.
4. Don't be surprised that the additional data flow from interfaces created for smart metering will require high powered servers or larger disk farms for existing applications. Don't be surprised that some of the key systems that need meter data are actually Excel spreadsheets that cannot handle the volume of data that new meters create.
5. Tuning interfaces for operations can take two or three times the effort of writing the interface. After the second effort to tune an interface, in most cases it is better to start over.
6. As the meter population grows, so will the need to re-tune interfaces
7. It may take two enterprise service buses (ESBs) to support smart metering. One, the enterprise ESB, will move non-time-critical data from system to system. The other ESB is time critical and moves alerts and alarms in a prioritized fashion from system to system. In most cases these ESBs need to be on separate hardware systems and in some cases in separate networks.
8. Be prepared for systems with limited documentation and a list of open bugs that are in the process of being fixed. Many of the systems are young and still evolving.

System integration is still evolving. The NIST effort will add more standards and cause existing standards to evolve. This is very useful from an interface maturity standpoint and an ease of integration effort. Waiting for NIST to finish and then the vendors to finish may not match the project's timeline, so a utility must be ready to make the evolutionary changes that may be required over time.

Additional Lessons Learned

Lesson 1: Everyone ignores the network until it is too late. Meters, installers, and other easier to deal with issues are the early focus of the project team. It is normally only after issues in bandwidth start to appear, or bills that are higher than expected for communications, that the network gets the focus it really needs.

Lesson 2: Everyone is surprised by the amount of data that is generated. Seeing the numbers on a white board or in a document does not prepare people for the reality. This lack of preparedness can lead to early bottlenecks and additional costs to handle the data.

Lesson 3: Organizational change management starts too late. People assume that the change comes when the meters are in. In reality, the organization will have to change at least three times. First, at production installation start; second, when the volume of smart meters becomes large enough that exception processing it is too cumbersome; and third, when the smart meters are almost all in.

Lesson 4: Billing systems take a long time to change and can be the gating item in software. Starting any billing system changes early can pay big dividends later. Knowing what can be changed and what the billing system should do is also a critical step in the process.

Lesson 5: Meter data management systems (MDMS) are not operational systems, so do not expect them to provide real time alerts and alarms. If real time outage messages are desired, that needs to happen somewhere else.

Lesson 6: Despite the publicity about in-home displays and home area networks (HAN), full-function integrated systems have yet to be implemented, and little real-world experience is available on customers will respond.

Lesson 7: Most existing drive-by and one-way metering systems will probably be replaced before they reach their design life. Smart metering systems that do not take into account reasonable, future requirements will also probably be replaced early.

Lesson 8: MDMS are not critical for pilots and early test rollouts. If personnel resources are limited for the project, the MDMS can probably wait.

Lesson 9: In a typical utility, it will take two years after completing a rollout before many of the ways the data will actually be used the data will become clear. It will take time for people in the organization to explore the data, talk to others and come up with some of the higher value uses of the data. Most of these uses will not be in the business case.

Lesson 10: Failing to get good data from the field, while installers are in the field, is a mistake. Photos, GPS, and other data should be collected by the field team if reasonably possible. Going back to get it later is expensive.

These lessons learned may help utilities implement successful smart metering projects and avoid some of the mistakes made in previous implementations.

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