Oakley Greenwood

Review of AMI Benefits

Melbourne +613 9486 0897 **Sydney** +612 8006 8107 **Adelaide** +618 8331 1358 **Brisbane** +617 3263 7612

DISCLAIMER

This report has been prepared for the Victorian Department of Primary Industries (DPI) to assist with policy development and strategic decision making in regard to the Advanced Metering Infrastructure (AMI) Rollout and Program.

The analysis and information provided in this report is derived from information prepared by a range of parties other than Oakley Greenwood (OGW), and OGW explicitly disclaims liability for any errors or omissions in that information, or any other aspect of the validity of that information. We also disclaim liability for the use of any information in this report by any party for any purpose other than the intended purpose.

In particular, this report is not intended to be used to support business cases or business investment decisions, nor is it intended for use in relation to regulatory cases such as for cost recovery or tariff setting purposes. The suitability of estimates in this report has been assessed based on their materiality in relation to the overall benefits of the Victorian AMI Rollout and AMI Program. Therefore, the estimates benefits and other opinions expressed in this report should be read in relation to the overall objective for this report of estimating the aggregate jurisdictional benefits of AMI for Victoria, and should not be read as opinions in relation to those benefits for specific individuals or businesses, or for specific items or systems. Readers of this report should be aware that it does not take into account the circumstances of specific companies or electricity customers.

DOCUMENT INFORMATION

Project	Review of AMI Benefits
Client	Department of Primary Industries
Status	Final Report
Report prepared by	L Hoch S James, J Snow
Date	July 2010

Table of CONTENTS

Table of FIGURES

Table of TABLES

1. Executive Summary

1.1. Background and approach

This report provides a review of material that has been produced for the Victorian Government concerning the benefits of its Advanced Metering Infrastructure (AMI) Program. That program includes but is more comprehensive than the AMI Rollout that commenced in 2009. The information provided in this report will serve as an input to an assessment of the costs and benefits of both the AMI Rollout and AMI Program, and a public consultation process that the Department will run over the course of the coming months.

More specifically, this report provides an independent review of the material contained in *Advanced Metering Infrastructure Program - Benefits Realisation Roadmap* (the 2009 Benefits Report)[1], which was prepared by Futura Consulting, and which contains the most recent assessment of the benefits of the Victorian Government's AMI Program.

In undertaking our review of the 2009 Benefits Report we:

- Focussed on the low case estimate of benefits as a means of assessing whether the likely benefits of AMI exceed its costs.
- Undertook a more limited review of the high case in the 2009 Benefits Report. The more limited scope of this review was consistent with the lower importance of high case benefits when assessing the Government's policy to implement the AMI Program. Where a material change to a low case estimate from the 2009 Benefits Report has been made, we have ensured that the high case was addressed in a comparable manner; and
- Concentrated our review on the benefits with the largest values in the 2009 Benefits Report, which are those that have the most impact on whether the aggregate benefits of AMI exceed its costs; this was particularly appropriate given that just 11 of the 38 benefits identified in the 2009 Benefits Report accounted for over 82% of total AMI benefits, and just over half the benefits (20) accounted for over 95% of total benefits.

1.2. Review of AMI benefits

1.2.1. Overall results - low case

The review of the AMI benefits included an examination of the methodology and data inputs used in the 2009 Benefits Report in estimating the value of the 38 benefits that had been identified and a review of the consistency of the general economic and market assumptions that had been used in the 2009 Benefits Report and the 2010 Cost Report[2] so that their results could be combined in the benefit/cost assessment that is to be conducted as a further phase of this work. The results of the review included adjustment to the benefit values that resulted from:

- adjustments that needed to be made to ensure consistency in general economic and market assumptions; these adjustments affected all but three of the 38 benefits, though in all but one case were quite minor in magnitude;

---

1 Futura Consulting, *Advanced Metering Infrastructure Program - Benefits Realisation Roadmap*, for Department of Primary Industries (Vic), December 2009.

2 Energy Market Consulting Associates and Strata Energy Consulting, *Updated Assessment of AMI Costs for Victoria*, for Department of Primary Industries (Vic), June 2010.

- changes to the approach and data input values used in estimating the value of 11 of the benefits; and
- the addition of one benefit that had not been identified in the 2009 Benefits Report.

The 2009 Benefits Report calculated the present value of the benefits of AMI under its low case assumptions as $2.481 billion (2008$).

Based on the review we have undertaken, we estimate those benefits at $2.577 billion (2008$). Of the $96 million difference between the two studies:

- Changes made to the general economic and market assumptions in order to ensure consistency between the cost and benefit information used in the benefit/cost assessment to be undertaken subsequently resulted in a net addition of approximately $84 million to the present value of the AMI benefits.
- Changes made to the data inputs used in specific benefit calculations resulted in a net addition of approximately $12 million to the present value of the AMI benefits, though this was a result of some benefit values increasing and others decreasing. More specifically,

  The present value of five benefits was decreased by a total of $618 million.

  - The values of two benefits were reduced to zero. Benefit 11, *Ability to set emergency demand limits to share limited supply at times of network stress or supply shortage* was reduced to zero because the input data assumptions on which the benefit calculation in the 2009 Benefits Report was not felt to be sufficiently robust. It should be noted, however, that we strongly believe that this is a real benefit with a non-zero value, but one that, at this point, may be better thought of as an insurance benefit, rather than a benefit that will deliver monetary value within any specific timeframe. The other was Benefit 38, *Revenue from reading smart water meters for water utilities*, which was reduced to zero because the revenue is a transfer, not a net societal benefit.
  - The value of three other benefits were reduced by 23% to 60%, these included:
    - Benefit 8, *Avoided additional cost of energy from time switch clock errors* was reduced by $11 million (23%) due to the net effect of the value of avoided energy costs having been over-estimated, and the value of avoided generation and network augmentation having been omitted in the 2009 Benefits Report;
    - Benefit 29, *Avoided network and generation augmentation from peak demand reduction from three-rate TOU network tariff introduction and resultant three-rate retail tariff* was reduced by $45 million (51%) due to the net effect of our view that the take-up rate of 80% that had been assumed was significantly too high, and the value of avoided augmentation costs having been too low;
    - Benefit 31, *Energy conservation from three-rate TOU tariff* was reduced by $74 million (60%) due to the same factors discussed with regard to Benefit 29 immediately above.

  The present value of six benefits was increased and an additional benefit was identified and quantified, which in total added $629 million in present value.

- The six benefits whose values were increased were:
  - Benefit 6, *Avoided cost of special reads* was increased by $25 million (18%) because the cost of conducting a special read had been under-estimated;
  - Benefit 9, *Avoided cost of manual disconnections and reconnections* was increased by $219 million (156%) due to corrections (increases) to each of the following inputs: the avoidable cost of the service, the number of disconnects and reconnects performed in an average year, and the amount of unserved energy that would be avoided; and the use of a more appropriate value (which was higher than the value that had been used in the 2009 Benefits Report) for the unserved energy avoided by this functionality;
  - Benefit 19, *Reduction in unserved energy (with quicker detection of outages and quicker restoration times)* was increased by $247 million (196%) because the base SAIDI figures and load on which the value of this benefit had been calculated had been underestimated, and the impact of this functionality on SAIDI was revised upwards based on further analysis of available overseas information;
  - Benefit 22, *Avoided cost of a proportion of transformer failures on overload* was increased by $7 million (35%) because the reduction in unserved energy provided by this benefit had not been accounted for;
  - Benefit 30, *Avoided network and generation augmentation from peak demand reduction from CPP tariff implementation* was increased by $60 million (82%) because the value of avoided generation and network augmentation used in the 2009 Benefits Report was too low, and we felt that the benefit would accrue more quickly than assumed in the 2009 Benefits Report; and
  - Benefit 34, *Additional demand response from direct load control of air conditioners* was increased by $26 million (31%) for the same reasons as discussed with regard to Benefit 30 immediately above.
- The value of the benefit that could be obtained due to the additional information that could be provided to consumers due to AMI regarding their energy use, a benefit that had not been addressed in the 2009 Benefits Report (Benefit 35a), was estimated at $44 million in present value terms based on the results of efforts of this type that have been undertaken overseas.

Table 1 below shows the changes that have resulted in the estimate of AMI benefits from the review undertaken of the low case presented in the 2009 Benefits Report. The table lists the benefits in order of their benefit number in the 2009 Benefits Report, and separates the impacts of the changes made to general economic and market assumptions from those made to particular data inputs to specific benefits.

Table 1: Comparison of low benefit values from the 2009 Benefits Report and the low benefit values from this review

Benefit No	Benefit	Value (2008$ M[3]) in		Amount (2008$ M[1]) due to change in		Most significant benefit-specific changes[4]
		2009 Benefits Report (low)	OGW Review[5] (low)	General economic and market assumptions[6]	Benefit-specific inputs[7]	
1	Avoided costs of installing import / export metering	33	35	2	0	
2	Avoided costs of meter replacement	455	492	37	0	
3	Reduced testing of meters	7	7	0	0	
4	Reduced cost of network loading studies for network planning	5	5	0	0	
5	Avoided cost of routine reading (including reductions in costs of PDEs and route management)	290	298	8	0	
6	Avoided cost of special reads	139	171	8	25	Cost per read revised upwards
7	Avoided cost of time switch replacement and O&M	93	99	5	0	

3 Rounded to nearest million dollars.

4 The methodology and benefit-specific inputs used in the 2009 Benefits Report have been accepted unless otherwise noted.

5 Shaded cells indicate those benefits whose methodologies and/or benefit-specific inputs have been revised in the OGW review.

6 See Section 4.2 for a discussion of these assumptions.

7 These are discussed on a benefit-by-benefit basis in Section 4.3.

Benefit No	Benefit	Value (2008$ M[3]) in		Amount (2008$ M[1]) due to change in		Most significant benefit-specific changes[4]
		2009 Benefits Report (low)	OGW Review[5] (low)	General economic and market assumptions[6]	Benefit-specific inputs[7]	
8	Avoided additional cost of energy from time switch clock errors	48	41	3	-11	Energy cost savings revised downwards Augmentation savings that had been overlooked were added
9	Avoided cost of manual disconnections and reconnections (and avoided revenue loss)	140	364	5	219	Cost per disconnect/reconnect revised downwards Average hours of unserved energy revised upwards Used a more representative VCR value Incidence of the service revised upwards for one DB
10	Avoided cost of setting demand limits for customers to promote fair sharing and defer augmentation capex	5	5	0	0	
11	Ability to set emergency demand limits to share limited supply at times of network stress or supply shortage	422	0	6	-428	Input used for VCR has no empirical base Historical base used is highly variable Benefit of a highly probabilistic nature; more appropriately characterised as an insurance value
12	Avoided cost of supply capacity circuit breaker	4	4	0	0	
13	Avoided cost of replacing service fuses that fail from overload	5	5	0	0	

Benefit No	Benefit	Value (2008$ M[3]) in		Amount (2008$ M[1]) due to change in		Most significant benefit-specific changes[4]
		2009 Benefits Report (low)	OGW Review[5] (low)	General economic and market assumptions[6]	Benefit-specific inputs[7]	
14	Avoided cost of investigation of customer complaints about voltage QoS, including equipment cost and cost of reporting to regulator	38	39	1	0	
15	Reduced cost for post storm supply restoration - avoid delays in detecting and correcting nested outages	9	9	0	0	Accepted the methodology and inputs in the 2009 Benefits Report but also note that the benefit value needs to be revised upwards materially due to the lack of data with which to accurately estimate the avoided unserved energy and the reduced need for DB fault restoration labour
16	Reduction in calls to faults and emergencies lines	14	14	0	0	
17	Avoided cost of investigation of customer complaints of loss of supply which turn out to be not a loss of supply	14	15	1	0	
18	Avoided cost of end of line monitoring	4	4	0	0	
19	Reduction in unserved energy (with quicker detection of outages and quicker restoration times)	126	375	2	247	Base SAIDI figures were revised Impact on SAIDI revised upwards Benefit had been conceptualised as affecting only small-volume customers, but will actually affect all customers
20	Avoided cost of communications to feeder automation equipment	3	3	0	0	
21	Avoided cost of proportion of HV/LV transformer fuse operations on overload	5	5	0	0	

Benefit No	Benefit	Value (2008$ M[3]) in		Amount (2008$ M[1]) due to change in		Most significant benefit-specific changes[4]
		2009 Benefits Report (low)	OGW Review[5] (low)	General economic and market assumptions[6]	Benefit-specific inputs[7]	
22	Avoided cost of a proportion of transformer failures on overload	20	28	0	7	Reduction in USE due to this benefit had not been accounted for
23	Reduction in calls related to estimated bills and high bill enquiries	5	5	0	0	
24	Reduction in energy trading costs through improved wholesale forecasting accuracy	8	8	0	0	
25	Reduction in the administration cost of bad debt incurred on non-payment on move outs	2	2	0	0	
26	Customer benefit of being able to switch retailer more quickly and more certainly. Note: this is not the bill saving	7	8	0	0	
27	Reduction in MDA costs - putting I&C customers on DB AMI networks	25	26	0	0	
28	Ability for customers to move to monthly billing on the basis of electronic bills, reducing, admin costs, collection costs etc	0	0	0	0	
29	Avoided network and generation augmentation from peak demand reduction from three-rate TOU network tariff introduction and resultant three-rate retail tariff	89	44	0	-45	Take-up of the TOU tariff revised downwards Cost of avoided infrastructure revised upwards
30	Avoided network and generation augmentation from peak demand reduction from CPP tariff implementation	73	133	0	60	Cost of avoided generation and network infrastructure revised downwards Benefit will accrue as rollout proceeds, not just when rollout is complete

Benefit No	Benefit	Value (2008$ M[3]) in		Amount (2008$ M[1]) due to change in		Most significant benefit-specific changes[4]
		2009 Benefits Report (low)	OGW Review[5] (low)	General economic and market assumptions[6]	Benefit-specific inputs[7]	
31	Energy conservation from three-rate TOU tariff	123	49	0	-74	Take-up of the TOU tariff revised downwards Cost of avoided energy had been understated
32	Energy conservation from CPP tariff implementation	10	10	0	0	
33	Additional demand response from IHDs on CPP	4	4	0	0	
34	Additional demand response from direct load control of air conditioners	85	113	1	26	Cost of avoided generation and network infrastructure revised upwards Benefit will accrue as rollout proceeds, not just when rollout is complete
35	Energy conservation from IHDs	49	50	1	0	
36	Peak demand reduction through deferral of refrigerator auto defrost cycle out of peak period	28	28	1	0	
37	Avoided cost of other communications to manage customers' loads for renewable generation tracking, electric vehicle charging and local generation management	34	35	1	0	
38	Revenue from reading smart water meters for water utilities	60	0	1	-60	AMI enables this benefit, but it should be taken up in the cost-benefit case for water meters Payments from water companies to DBs is a transfer, not a benefit
35a	Energy conservation from general information programs		44	0	44	Benefit had not been addressed
Total		2,481	2,577	84	12	

1.2.2. Overall results - high case

Our review of the 2009 Benefits Report high case values has been limited as its purpose is to inform the Government's deliberations surrounding the policy decision to proceed with the AMI Rollout, which was not based on the high case value of benefits. Hence, a detailed review of the high case value of benefits is only useful when considering the up-side of the AMI Program.

Therefore, the review of high case benefits focused on those benefits that were materially impacted by changes to the benefit-specific inputs and were revised in our review of the 2009 Benefits Report's low case. In order to ensure our opinions are consistently presented, which ensures comparability between our low and high case benefit values, we have applied the same revisions in the review of the 2009 Benefit Report's high case benefits as we applied in our review of its low case. In some cases, additional inputs were adjusted in the review of specific high case benefit estimates. As in the low case review, the high case review has materially affected 11 of the 39 reviewed benefits and resulted in the high case estimate of $6.507 billion (as detailed in the 2009 Benefit Report) being revised downwards to $5.004 billion, which is a reduction of $1.503 billion (see section 4.5 for further detail).

1.2.3. Categorisation of benefits by likelihood of realisation

The benefits identified and discussed in the 2009 Benefits Report can be categorised by the conditions that need to pertain in order for their value to be realised. Based on our review of the benefits as described in the 2009 Benefits Report we have identified the following four categories, listed in increasing stringency of the conditions they require for benefit realisation:

1. Benefits that result directly from the operation of the AMI technology as specified for the Victorian AMI Rollout;
2. Benefits that result directly from the operation of additional AMI functionality that will require additional expenditure beyond that needed to meet the *Minimum AMI Functionality Specification (Victoria)*;
3. Benefits that require legislative, regulatory or market rules changes on the part of Government, the AEMC, or the AEMO; and
4. Benefits that require electricity retailers and/or electricity consumers to undertake discretionary actions.[8]

Table 2 on the following page summarises the number and value of the benefits re-estimated in this review in each of these categories.

8 A number of the benefits require actions that apply to more than one of the categories. For example, a benefit might require (or at least profit from) Government action as well as voluntary actions on the part of retailers or consumers. In such cases, the benefit was put in the category that represented outcomes that are least certain. For example if a benefit required both Government action and voluntary action by an electricity retailer, it was placed in category 4.

Table 2: Value of low case benefits by likelihood of realisation

Category No	Benefit category of likelihood	No of benefits	Aggregate benefit value	% of total benefit value
1	Benefits resulting from operation of AMI technology (as specified for the Victorian AMI Rollout)[9]	11	1,531	59.4%
2	Benefits resulting from operation of additional AMI technology (as identified in the 2009 Benefits Report)	15	505	19.6%
3	Benefits requiring legislative, regulatory or market rules changes	4	66	2.6%
4	Benefits requiring discretionary retailer or customer action	9	475	18.4%
Total		39[10]	2,577	100.0%

9 This category includes the benefits from the AMI technology as detailed in *Minimum AMI Functionality Specification (Victoria)*, September 2008, for the Victorian AMI Rollout and from the additional functionality identified in the 2009 Benefits Report. As in the case of other benefits, the benefits of the additional functionality are calculated without accounting for the associated costs. The costs of these additional functionalities are also addressed in the 2009 Benefits Report.

10 The 2010 Benefits Review identified one additional benefit that could be obtained from the AMI Program functionality, namely Benefit 35a, Energy conservation from general information programs.

2. Background and Purpose

This report provides a review of material that has been produced for the Victorian Government concerning the benefits of its Advanced Metering Infrastructure (AMI) Program. That program includes but is more comprehensive than the AMI Rollout that commenced in 2009. The information provided in this report will serve as an input to an assessment of the costs and benefits of both the AMI Rollout and AMI Program, and a public consultation process that the Department will run over the course of the coming months.

The process of which this review is a part began in 2000 with the formation of the Victoria Infrastructure Planning Council (IPC), which over the course of 2001 and 2002 conducted a study and public consultation process regarding Victoria's infrastructure needs over the next 20 years. The need to reduce the growth in daily and seasonal peak demand for electricity as a means for controlling capital expenditure and improving the economic efficiency of the state's electricity infrastructure was one of its primary findings. This was consistent with the findings of a 2002 review by the Council of Australian Governments (COAG) which identified the rollout of interval meters as a means of making consumers aware of the pattern of their electricity use over time, sending price signals that would better reflect the true cost of meeting the consumer's electricity demand, and thereby promoting more economically rational end-use of electricity, reducing cross subsidies between customers and customer classes, and encouraging demand management and energy efficiency.

Subsequently, in 2004, after evaluation and consultation, the Essential Services Commission (ESC) mandated the five Victorian electricity distribution companies to replace existing accumulation meters with electronic interval meters for all consumers that use less than 160MWh/year (referred to as small consumers). The replacement of all accumulation meters was to be accomplished over a period of 20 years, with all new connections to be fitted with interval meters, the meters of load-control customers replaced on an accelerated basis, and the remaining stock of accumulation meters switched out on a specified replacement schedule.

Concerns were expressed by consumer groups and members of the electricity industry that the ESC's approach failed to consider the value that common protocol, two-way communications could bring to meeting the objectives which had informed the mandate in the first place. In response the Energy Division, then within the Department of Infrastructure, commissioned CRA International and Impaq Consulting to prepare a study of the incremental costs and benefits of adding two-way communications to the meters that the ESC had mandated to be rolled out. The study also assessed the value of an accelerated rollout schedule.

In 2006, following the publication of that study the Victorian Government replaced the ESC mandate with a commitment to roll out an advanced metering infrastructure (interval meters with two-way communications) to all small consumers on an accelerated basis (over a period of about four years). This commitment was executed through an Amendment to the Electricity Industry Act 2000 (Vic).

The incremental approach and the economic grounds on which the Government's decision was made were challenged by the Auditor-General in 2009, however, citing the existence of significant differences in the estimates of costs and benefits of the infrastructure that had been made by industry, a national study of costs and benefits[11], and those contained in the studies that the Victorian Government had relied upon.

11 The National Smart Meter Cost Benefit Analysis, which was undertaken in 2007 and 2008 on behalf of the Ministerial Council on Energy (MCE).

In the meantime the Victorian Government, through the Energy Division (which had by then been migrated to the Department of Primary Industries) had established the AMI Project, a collaborative project involving government, industry, consumer groups, market operators and regulators, under the direction of an AMI Industry Strategy Group (ISG). The ISG had, among other things, considered the regulatory framework that would be needed to support AMI. A significant element of this was the development and implementation of arrangements whereby the distribution businesses would recover the costs of the rollout, and the development of and application for suitably supportive changes to the National Electricity Rules.

In 2008 the distributors submitted cost-recovery proposals that indicated costs significantly different from those estimated in the various studies that had been published by the ESC, the Energy Division and the MCE. The Energy Division commissioned Energy Management Consulting Associates (EMCa) to review the distributors' cost estimates and provide an independent update of AMI technology costs. The results of that study were used – in consultation with the distributors – to amend the cost recovery arrangements and better manage cost risks.

The distributors then submitted their revised cost estimates for the AMI Rollout as part of their regulatory price determination proposals to the AER, which had since assumed responsibility for this and other aspects of the regulation of electricity distribution. The AER approved budgets for the distributors on 30 October 2009.

In response to those budgets and the Auditor-General's report, the Energy Sector Development Division (ESD), which is what the Energy Division had been renamed, commissioned two additional studies:

- EMCa was commissioned to "review the distributors' budget proposals and establish a new baseline cost for the AMI Rollout" (the 2009 Cost Report[12]), which was updated in April 2010 and finalised in July 2010 (the 2010 Cost Report[13]) to "take account of the AMI budget and charges applications for 2010 and 2011provided to the Australian Energy Regulator (AER) by the five Victorian distribution Businesses (DBs), the AER's final determination, on these applications and the outcome of the appeal by two of the Victorian DBs (Jemena and UED) to the Australian Competition Tribunal"; and
- Futura Consulting was commissioned "to review the benefits of the AMI Program, and also advise on activities that may need to be undertaken to ensure that these benefits could flow, to the maximum extent, to consumers" (the 2009 Benefits Report[14]).

ESD is now seeking an independent review of the 2009 Benefits Report, including the conduct of a benchmarking exercise of the benefits of AMI identified elsewhere, and the preparation of a benefit/cost analysis, which will integrate the results of that independent review of the 2009 Benefits Report and those of the 2010 Cost Report.

---

12 Energy Market Consulting Associates and Strata Energy Consulting, *Updated Assessment of AMI Costs for Victoria*, for Department of Primary Industries (Vic), October 2009.

13 Energy Market Consulting Associates and Strata Energy Consulting, *Updated Assessment of AMI Costs for Victoria*, for Department of Primary Industries (Vic), June 2010.

14 Futura Consulting, *Advanced Metering Infrastructure Program - Benefits Realisation Roadmap*, for Department of Primary Industries (Vic), December 2009.

The 2010 Cost Report, the 2009 Benefits Report and this review of the benefits of AMI will serve as inputs to a public consultation process that the ESD plans to conduct over the coming months. The purpose of the independent review of the 2009 Benefits Report that is the subject of this report is to provide additional assurance to all stakeholders that the estimated benefits of the AMI Rollout and the larger AMI Program have been subjected to robust and rigorous peer examination.

In addition, this review is intended to bring together the results of the 2010 Cost Report with the revised estimate of AMI benefits using consistent assumptions and a recognised economic framework. This is meant to provide assurance to stakeholders of the soundness and consistency of the analysis of the costs and benefits, and aid in communication of the results.

3. Approach of the Review and Structure of this Report

3.1. Approach

This report provides our review of the benefits of AMI. The approach taken for addressing these elements of the scope of work included the following:

- Reviewing the material contained in *Advanced Metering Infrastructure Program - Benefits Realisation Roadmap* (the 2009 Benefits Report), which was prepared by Futura Consulting. This review included examination of:
  - the completeness of the list of benefits considered, including whether any relevant benefits (whether quantifiable or not)[15] have been omitted, and whether any of the benefits addressed are more accurately defined as transfers;
  - the soundness and appropriateness of the specific methodologies used to assess the magnitude of each of those benefits, and the consistency of those methodologies across benefits;
  - the appropriateness of the technical inputs and assumptions used in estimating each benefit, and the consistency of these inputs and assumptions across benefits;
  - the appropriateness of the economic assumptions used in estimating each benefit, and the consistency of these assumptions across benefits and studies;
  - the potential sensitivity of results to changes in critical assumptions; and
  - the magnitude of the benefits that have been estimated in light of the considerations above and our knowledge of the magnitude of the benefits estimated in other studies.

  It is important to recognise that this was a review and neither an audit of the work undertaken in preparing the 2009 Benefits Report nor an independent calculation of AMI benefits from first principles. Rather, the material presented in the 2009 Benefits Report was examined to form an opinion as to the reasonableness of the assumptions it used and the adequacy of and documentary support for the other inputs it used.

- Reviewing the material contained in other benefit/cost assessments of AMI and related matters (such as the results of the impacts of trials that have been undertaken of innovative pricing arrangements made possible by interval metering). A list of the studies reviewed appears in Appendix A. Where these sources have provided useful information they are referenced in subsequent sections of this report. Many of the studies – particularly those that addressed the costs and benefits of AMI in other jurisdictions – were of only limited applicability for the purpose of the current study. This is the case for several reasons, including:
  - In most cases, these studies were undertaken before AMI was implemented, and therefore provide only predictions of costs and benefits, rather than actual outcome costs or benefits;
  - Most of the studies were undertaken at a much less granular level than the studies that have been undertaken in Australia; as a result, most did not quantify AMI benefits at the level of disaggregation that is being undertaken in the 2009 Benefits Report;

15 For example, new technology may facilitate increased choice on the part of the consumer, although the benefit derived from the availability of that additional degree of choice may be very difficult to quantify.

- The cost and benefit information that did exist was often a very specific result of the context in which it was developed; for example, meter reading costs – the avoidance of which is a major benefit of AMI – is dependent on local labour costs, population density and how frequently meters are read pre-AMI implementation. Differences in these factors will produce wide variation in the benefit value of different AMI functionalities, all of which may be correct for their local areas, but often have no relationship across local areas.

3.2. Relationship of this report to other work

Section 4 contains our review of the benefits claimed in the 2009 Benefits Report, including those revisions we recommend.

A consolidated benefit/cost assessment of both the AMI Rollout and the AMI Program, based on the benefits of AMI (as revised in this report) with their costs (as reviewed in the 2010 Cost Report and the 2009 Benefits Report for those benefits that rely on functionality that is not included in the *Minimum AMI Functionality Specification*) is presented in a separate report.

4. Review of Benefits Claimed in the 2009 Benefits Report

4.1. Overview and categorisation of benefits claimed

The 2009 Benefits Report identified and quantified 38 benefits that result from the deployment and use of AMI, 17 of which had been identified, discussed and quantified in the *National Smart Meter Cost Benefit Analysis* (National CBA) undertaken in 2007 and 2008 on behalf of the Ministerial Council on Energy (MCE), and an additional 21 benefits of AMI that had either not been identified in the MCE study, or had been identified but not quantified.

For each of the 38 benefits the 2009 Benefits Report:

- provides a low and high case estimate of the present value of the benefit;
- identifies whether the benefit results from the functionality specified in the initial Victorian AMI Rollout or will require additional functionality and investment including that required to meet the functionality specification being considered for implementation under the National Smart Metering Program (NSMP);
- identifies whether the benefit will be realised progressively as the rollout takes place, or will not be realised until the rollout has been completed, or until sometime after the rollout has been completed;
- identifies whether additional systems or equipment are required for the benefit to be realised, and the cost of any such systems or equipment; and
- identifies whether additional regulatory or legislative action is required for the benefit to be realised.

The 2009 Benefits Report categorised the benefits of AMI as originating from three different sources: network operations, retail operations, and customer demand response benefits and home area network (HAN) operation. However, given the purpose of this review – which is to critically review the magnitude of the benefits presented in the 2009 Benefits Report, their likelihood of being realised, and the relationship between the magnitude of those benefits and the costs of the AMI infrastructure – we have chosen to review the benefits from a different perspective, as follows:

- We have concentrated our review on the low case estimate of benefits[16] – Because we are primarily interested in determining if the likely benefits of AMI exceed its costs we are more concerned with calculating the most conservatively likely level of benefit to be obtained rather than how big the benefit might be under more favourable conditions or assumptions;
- We have concentrated our review on the benefits with the largest value in the 2009 Benefits Report – Those benefits have the most impact on whether the aggregate benefits of AMI exceed its costs, though in some cases we also took into account the difference between the low and high case estimates in the 2009 Benefits Report as an indicator of the potential materiality of a particular benefit to the aggregate benefit;
- We have categorised benefits in terms of whether they accrue primarily as a result of the technology itself, or whether they require further legislative, governmental or regulatory action on the one hand, or decisions and behaviour on the part of electricity retailers or end-use customers on the other.

16 A more limited review of the high case estimate of AMI benefits has also been undertaken.

Table 3, which commences on page 19, provides an overview of the value and other aspects of the benefits as estimated and discussed in the 2009 Benefits Report, including:

- the benefit number assigned to each benefit in the 2009 Benefits Report, in order to allow ready cross reference to the discussion of each benefit in that document;
- the low and high case present value (in millions of 2008 dollars) estimated for each benefit in the 2009 Benefits Report, and the range between those estimates – the benefits are listed in descending order of the magnitude of their estimated present value in the low case, in order to identify the materiality of each benefit to the aggregate present value of the low case as estimated in the 2009 Benefits Report;
- the cumulative value of the low case benefits in monetary terms and as a percentage of the total value of all low case benefits;
- whether the benefit is assumed to be realised progressively as the rollout takes place, once the rollout has been completed or sometime after the rollout has been completed;
- whether realisation of each benefit depends on either (a) additional legislation, regulation or other government actions, or (b) voluntary actions on the part of the electricity retailers[17] or end users.

As can be seen, the first 11 benefits account for 82% of the total low case benefits estimated in the 2009 Benefits Report. In addition, of these 11:

- 6 involve benefits that should accrue primarily from the exercise of the functionality of the AMI infrastructure and do not require either additional actions on the part of the Government, the Regulator, electricity retailers or end-use customers;
- the other 5 do require additional legislation, regulation or other Government actions and/or voluntary actions on the part of electricity retailers and/or end-use consumers.

The next 9 benefits (in order of their low case benefit value) bring the cumulative total to over 95% of the total low case estimate of benefits in the 2009 Benefits Report. Of those:

- 2 involve benefits that should accrue primarily from the exercise of the functionality of the AMI infrastructure and do not require either additional actions on the part of the Government, the Regulator, electricity retailers or end-use customers;
- the other 7 do require additional legislation, regulation or other Government actions and/or voluntary actions on the part of electricity retailers and/or end-use consumers in order for the benefits to be fully realised.

The remaining 18 benefits account for just over 5% of the aggregate benefit value, and the largest of these benefits accounts for only 0.6% of the total. Because of the small size of these benefits individually and in aggregate, they were not subjected to a detailed review. The exceptions to this were Benefits 15, 24 and 32 because there was a significant difference between their low and high case value estimates. As a result, a review of the methodologies and inputs used in valuing those benefits was undertaken.

17 The realisation of a number of the benefits requires that electricity distributors change current work practices. We have assumed that these changes will be undertaken due to (a) the benefits that the distributor can obtain, and (b) the potential for service standards to be implemented by the Regulator.

Section 4.3, which follows Table 3 below, provides a critical review of the 20 largest benefits discussed in the 2009 Benefits Report in descending order of their benefit value. Prior to those discussions we review the appropriateness of the general economic assumptions used in the 2009 Benefits Report, and the consistency of these assumptions with the 2010 Cost Report and across the benefits claimed.

Table 3: Overview of AMI benefits as calculated in the 2009 Benefits Report[18]

Benefit No	Benefit	Size of benefit (PV 2008$ M)			Cumulative benefits (low case)		Timing of realisation	Does realisation of benefit value depend on	
		Low	High	Range	PV 2008$ M	% Total		Enabling legislation, regulation or other Gov't actions (Y)	Voluntary actions by electricity retailers (R) or end user consumers (C)
2	Avoided costs of meter replacement programs	455	655	200	455	18.3%	Progressive		
11	Ability to set emergency demand limits to share limited supply at times of network stress or supply shortage	422	628	206	877	35.3%	On completion	Y	
5	Avoided cost of routine reading (including reductions in costs of PDEs and route management)	290	308	18	1,167	47.0%	Progressive		
9	Avoided cost of manual disconnections and reconnections (and avoided revenue loss)	140	385	245	1,572	52.7%	Progressive		
6	Avoided cost of special reads	139	211	72	1,432	58.3%	Progressive		
19	Reduction in unserved energy (with quicker detection of outages and quicker restoration times)	126	345	219	1,219	63.4%	On completion		
31	Energy conservation from three-rate TOU tariff	123	796	673	1,695	68.3%	Progressive		R C
7	Avoided cost of time switch replacement and O&M	93	170	77	1,962	72.1%	Progressive		

18 Information in the last two columns is based on OGW interpretation of information presented in Table 1 and the discussion of the realisation of each benefit in Sections 5 through 8 of the 2009 Benefits Report. The information in all other columns is taken directly from the 2009 Benefits Report.

Benefit No	Benefit	Size of benefit (PV 2008$ M)			Cumulative benefits (low case)		Timing of realisation	Does realisation of benefit value depend on	
		Low	High	Range	PV 2008$ M	% Total		Enabling legislation, regulation or other Gov't actions (Y)	Voluntary actions by electricity retailers (R) or end user consumers (C)
29	Avoided network and generation augmentation from peak demand reduction from three-rate TOU network tariff introduction and resultant three-rate retail tariff	89	521	432	1,784	75.7%	Progressive		R C
34	Additional demand response from direct load control of air conditioners	85	581	496	1,869	79.1%	On completion	Y	C
30	Avoided network and generation augmentation from peak demand reduction from CPP tariff implementation	73	465	392	2,035	82.0%	On completion	Y	R C
38	Revenue from reading smart water meters for water utilities	60	119	59	2,095	84.4%	On completion	Y	
35	Energy conservation from IHDs	49	74	25	2,192	86.4%	On completion	Y	C
8	Avoided additional cost of energy from time switch clock errors	48	97	49	2,143	88.4%	Progressive		
14	Avoided cost of investigation of customer complaints about voltage QoS, including equipment cost and cost of reporting to regulator	38	38	0	2,230	89.9%	On completion	Y	
37	Avoided cost of other communications to manage customers' loads for renewable generation tracking, electric vehicle charging and local generation management	34	257	223	2,264	91.3%	On completion	Y	
1	Avoided costs of installing import / export metering	33	147	114	2,297	92.6%	Progressive	Y	

Benefit No	Benefit	Size of benefit (PV 2008$ M)			Cumulative benefits (low case)		Timing of realisation	Does realisation of benefit value depend on	
		Low	High	Range	PV 2008$ M	% Total		Enabling legislation, regulation or other Gov't actions (Y)	Voluntary actions by electricity retailers (R) or end user consumers (C)
36	Peak demand reduction through deferral of refrigerator auto defrost cycle out of peak period	28	196	168	2,325	93.7%	Long term	Y	C
27	Reduction in MDA costs - putting I&C customers on DB AMI networks	25	36	11	2,350	94.7%	Progressive	Y	
22	Avoided cost of proportion of transformer failures on overload	20	73	53	2,370	95.5%	On completion		
17	Avoided cost of investigation of customer complaints of loss of supply which turn out to be not a loss of supply	14	14	0	2,384	96.1%	On completion		
16	Reduction in calls to faults and emergencies lines	14	14	0	2,398	96.7%	On completion		
32	Energy conservation from CPP tariff implementation	10	84	74	2,408	97.1%	On completion	Y	R C
15	Reduced cost for post storm supply restoration - avoid delays in detecting and correcting nested outages	9	71	62	2,417	97.4%	On completion		
24	Reduction in energy trading costs through improved wholesale forecasting accuracy	8	82	74	2,425	97.7%	On completion		
26	Customer benefit of being able to switch retailer more quickly and more certainly. Note: this is not the bill saving	7	15	8	2,432	98.0%	On completion		
3	Reduced testing of meters	7	33	26	2,439	98.3%	Progressive		

Benefit No	Benefit	Size of benefit (PV 2008$ M)			Cumulative benefits (low case)		Timing of realisation	Does realisation of benefit value depend on	
		Low	High	Range	PV 2008$ M	% Total		Enabling legislation, regulation or other Gov't actions (Y)	Voluntary actions by electricity retailers (R) or end user consumers (C)
4	Reduced cost of network loading studies for network planning	5	12	7	2,444	98.5%	On completion		
10	Avoided cost of setting demand limits for customers to promote fair sharing and defer augmentation capex	5	13	8	2,449	98.7%	On completion	Y	
13	Avoided cost of replacing service fuses that fail from overload	5	14	9	2,454	98.9%	Progressive	Y	
21	Avoided cost of proportion of HV/LV transformer fuse operations on overload	5	14	9	2,459	99.1%	On completion		
23	Reduction in calls related to estimated bills and high bill enquiries	5	5	0	2,464	99.3%	On completion	Y	
12	Avoided cost of supply capacity circuit breaker	4	7	3	2,468	99.5%	Progressive	Y	
18	Avoided cost of end of line monitoring	4	4	0	2,472	99.6%	On completion		
33	Additional demand response from IHDs on CPP	4	18	14	2,476	99.8%	On completion	Y	R C
20	Avoided cost of communications to feeder automation equipment	3	3	0	2,479	99.9%	On completion		
25	Reduction in the administration cost of bad debt incurred on non-payment on move outs	2	2	0	2,480	100.0%	On completion		

Benefit No	Benefit	Size of benefit (PV 2008$ M)			Cumulative benefits (low case)		Timing of realisation	Does realisation of benefit value depend on	
		Low	High	Range	PV 2008$ M	% Total		Enabling legislation, regulation or other Gov't actions (Y)	Voluntary actions by electricity retailers (R) or end user consumers (C)
28	Ability for customers to move to monthly billing on the basis of electronic bills, reducing, admin costs, collection costs etc			0	2,481	100.0%	Progressive		
	Total	*2,481*	*6,504*	*4,023*					

4.2. Appropriateness and consistency of general economic assumptions used

4.2.1. General economic assumptions

As part of our review we were to ensure that the assumptions regarding key economic and market-based parameters used in the 2010 Cost Report and the 2009 Benefits Report were consistent. A few inconsistencies were identified and in discussion with EMCa and Futura Consulting, agreement was reached on a set of values to be used for those assumptions in which inconsistencies had been found. These assumptions concerned:

- the number of customer premises affected during the AMI meter rollout period;
- the rate of AMI meter rollout; and
- the growth rate in customer and meter numbers in the years following the end of the AMI meter rollout.

Table 4 below shows the values adopted for those assumptions, and other general economic and market assumptions used in re-calculating the values of the 38 benefits identified in the 2009 Benefits Report, and in calculating the benefits and costs of the AMI Rollout and AMI Program.[19]

Table 4: General economic and market assumptions

Variable	Value	Source / comment
Number of customer premises affected during the AMI meter rollout period		As advised by EMCa, based on Order in Council
2009	2,539,965	
2010	2,576,071	
2011	2,618,482	
2012	2,660,528	
2013	2,703,315	
Penetration of AMI meter rollout at customer premises		As advised by EMCa
2009	1%	
2010	17%	
2011	49%	
2012	79%	
2013	100%	

19 The costs used in the cost-benefit assessment presented in Section 4.4.2 are based on the 2010 Cost Report, which used assumptions that were consistent with those shown in Table 4. The benefits shown in Table 3 above are those contained in the 2009 Benefits Report, which were calculated using values that differed from those shown in Table 4 for the first three and some of the other assumptions. All of the benefit values used in the cost-benefit assessment contained in Section 4.4.2 have been revised using the economic and market assumptions shown in Table 4. Additional revisions have been made on a benefit-by-benefit level as discussed in Section 4.3 below.

Variable	Value	Source / comment
Growth rate in customer and meter numbers in the years following the end of the AMI meter rollout	1.635%	Mid-point of the low/high range used for this variable in the MCE National CBA study
Discount rate	8%	Common discount rate used in all relevant reports: 2010 Cost Report, 2009 Benefits Report, and the consolidated cost- benefit analysis presented in Section 4.4.2 below
ESOO Victorian Market Region data		AEMO, *Electricity Statement of Opportunities*, 2009.
Average energy growth rate (low case)	0.70%	
Average MD growth rate (low case)	1.90%	
Peak demand 2008 (MW)	9,818	
Total (distribution system) energy 2008 (GWh)	36,800	AER, *Victorian Electricity Distribution Businesses Comparative Performance Report 2008*, Nov 2009
Net System Load Profile energy 2008 (GWh)	17,746	AER, *Victorian Electricity Distribution Businesses Comparative Performance Report 2008*, Nov 2009
Residential customers as percentage of total customers	87.1%	AER, *Victorian Electricity Distribution Businesses Comparative Performance Report 2008*, Nov 2009
Residential customer share of peak demand	41%	Accepted from 2009 Benefits Report
Residential customer share of distribution energy	34%	Futura estimate
Residential load multiplier for peak c.f. off-peak day	3	OGW estimate
Average load (kW) of customer not supplied (low case)	0.6	OGW estimate
Annual capital charge per MW installed	$200,000	The 2009 Benefits Report used $130,000/MW/yr for its assessment of low case benefits, a figure that accounts for generation but ignores network costs associated with generation augmentation. The value ascribed to deferral of network augmentation used in the National CBA study was $110,000/MW/yr, meaning that the combined value of peak demand reduction in that study was $240,000/MW/yr. However, because network deferral requires peak demand reductions to occur in specific areas and on specific time schedules, the effect of peak demand reductions may not defer an equivalent amount of network capacity. Therefore, we have judgmentally reduced the annual capital charge for a MW of peak demand to $200,000/MW/yr in order to be conservative.
Short run marginal cost (SRMC) of an open-cycle gas turbine (OCGT) ($/MWh)	$75.00	OGW estimate

Variable	Value	Source / comment
Load weighted average Vic RRP 2008 ($/MWh)		Market databases
11pm to 7am	$26.56	
7am to 3pm	$46.41	
3pm to 11pm	$54.65	
All periods	$43.42	
Value of customer reliability ($/MWh)		*Assessment of the Value of Customer Reliability (VCR)*, CRA International Pty Ltd for VENCorp, August 2008
Residential	$13,250	
Agricultural	$111,060	
Commercial	$90,760	
Industrial	$36,070	
Total	$47,850	

Table 5 below lists the values of the material input variables that were used in assessing the magnitude of benefits identified in the 2009 Benefits Report, along with explanatory comments where applicable. As can be seen, in the majority of the cases we have accepted the input values used in the 2009 Benefits Report. However, in some cases we adopted different input values from those used in the 2009 Benefits Report. These changes are also discussed in the review of each benefit presented in Section 4.3.

Table 5: Benefit-specific input values and assumptions used by OGW

Benefit No	Variable	Value	Comments
6	Cost of special meter read	$30.00	The 2009 Benefits Report used $21.54, (weighted average), but was replaced based on further review of the allowed service charges of the DBs
7	Average energy on controlled use circuits (kWh/yr)	2,500	Accepted from 2009 Benefits Report
7, 8	Number of time switches	549,000	Accepted from 2009 Benefits Report
8	Proportion of time switches with error	5%	Accepted from 2009 Benefits Report
8	Time switches shifted to operate between 7am to 3pm and 3pm to 11pm	50% each of those with errors	OGW estimate
8	Average capacity rating of water heater (kW)	4.5	OGW estimate
8	Coincidence factor for hot water heaters (% on at peak)	10%	OGW estimate

Benefit No	Variable	Value	Comments
9	Same day connection requests not completed	190,000	Accepted from 2009 Benefits Report
9	Average hours off supply	16	The figure of 8 hours was replaced based on further review undertaken by OGW in consultation with Futura Consulting
9	Customers annually affected by reconnection	22%	Accepted from 2009 Benefits Report
19	SAIDI reduction due to quicker detection and restoration of outages	10%	Revised by OGW based on international and local data provided by Futura Consulting; see Section 4.3.4
22	Transformers failing on overload per year	120	Accepted from 2009 Benefits Report
22	Time to replace failed transformer (hours)	6	Accepted from 2009 Benefits Report
22	Transformer failure reduction	40%	Accepted from 2009 Benefits Report
22	Average cost of transformer	$50,000	Accepted from 2009 Benefits Report
22	Number of customers per transformer	55	Futura Consulting
29	Peak demand reduction from 3 rate TOU tariff	2%	Accepted from 2009 Benefits Report
29, 31	TOU take-up rate	30%	The 2009 Benefits Report posited 80% TOU take-up. OGW does not believe it is likely to be this high, as discussed in Section 4.3.7.
30	Peak demand reduction from CPP tariff	15%	Accepted from 2009 Benefits Report
30, 32	CPP take-up	12%	Accepted from 2009 Benefits Report
31	Energy conservation from three-rate TOU tariff	1.5%	Accepted from 2009 Benefits Report
34	DLC take-up	10%	Accepted from 2009 Benefits Report
34	Growth in peak load per average customer	0.265%	Accepted from 2009 Benefits Report
34	AC penetration 2008	72%	Accepted from 2009 Benefits Report
34	Incremental peak demand reduction of DLC when coupled with TOU	19%	Accepted from 2009 Benefits Report
35a	Target customers as share of total customers	70%	OGW estimate
35a	Energy conservation from information programs	1%	OGW estimate based on information on international experience provided by Futura Consulting

4.2.2. Counterfactual

Any assessment of the benefits of a policy or program must consider what would have happened in the absence of its implementation – the counterfactual.

The counterfactual used in the low case estimate of the 2009 Benefits Report was that in the absence of the AMI Rollout the use of accumulation meters would continue. That is, that no interval metering and no two-way communications between the electricity supply industry and the meters at customers' premises would exist.

This counterfactual ignores the possibility that the electricity supply industry might have installed some interval meters and communications systems on its own, or that it might ultimately have installed such devices and systems universally. While these outcomes are possible (though the former much more so than the latter), it is important to consider both (a) why the policy was considered in the first place, and (b) the issues raised by the Victorian Auditor-General.[20]

The Essential Services Commission made its original mandate regarding the progressive implementation of manually read interval meters because virtually no activity with regard to this technology was being evidenced on the part of the state's electricity distributors for small electricity users. Subsequent decisions augmented that decision to include accelerated deployment of the meters and adding two-way communications functionality. In its review of the AMI program, the Auditor-General's report questioned the basis and evidence used in the overall process, and stated that the government's "incremental approach to assessing the net benefits of the AMI project failed to provide a complete perspective of the AMI project on a consolidated basis".[21]

In order to update its understanding of benefits and costs the Department commissioned the 2009 Benefits Report and the 2010 Cost Report. Both of these reports use current information about the costs and benefits of AMI. They both also use the continuation of accumulation meters as the counterfactual. This is appropriate given the fact that consideration of the policy was first undertaken at a time when interval meters were not being deployed and the fact that virtually all deployment of interval metering to small electricity consumers in Victoria has been undertaken within a policy context in which that deployment was to be mandated, and with the Auditor-General's view that the net benefit of the AMI project be provided on a consolidated basis.

4.3. Review of low case AMI benefits

All benefit values discussed in this report represent the total present value of the benefit without consideration of the cost (whether that be a capital, operating or transaction cost) required to obtain the benefit.[22] Costs have been considered separately, in the 2010 Cost Report and the 2009 Benefits Report (in the case of benefits that rely on functionality that is not included in the *Minimum AMI Functionality Specification*), and are then brought together with the benefits to provide information on the net benefits of the AMI Rollout and AMI Program in a separate report.

---

20 Victorian Auditor-General, *Towards a 'smart grid' - the roll-out of Advance Metering Infrastructure*, November 2009.

21 Ibid, p 22.

22 It should be noted that a number of the benefits of AMI discussed in the 2009 Benefits Report and here are actually avoided costs – for example the avoided costs of routine and special meter reads. The values discussed in this report are those presented in the 2009 Benefits Report.

The benefits in the following sections are listed in descending order of the magnitude of their estimated present value in the low case, in order to identify the materiality of each benefit to the aggregate present value estimated in the 2009 Benefits Report.

4.3.1. Benefit 2: Avoided cost of meter replacement programs

Overview of Futura approach and key inputs

This benefit is comprised of the avoided cost of the meters that would have been installed in the absence of the AMI Rollout. The 2009 Benefits Report used the same assumptions about the types of meters that would have been installed in the absence of AMI as was made in the MCE's National CBA study.[23]

OGW comments

The assumptions, inputs and methodology used in estimating the value of this benefit are reasonable.

Revised benefit assessment

The value of this benefit is accepted as calculated in the 2009 Benefit Report, except to incorporate an adjustment to account for earlier inconsistencies in assumptions with respect to customer numbers, AMI meter numbers and customer number growth rates.

The revised inputs discussed above result in a present value for this benefit of $492 million, an increase of $37 million from the $455 million calculated in the 2009 Benefits Report.

4.3.2. Benefit 11: Ability to set emergency demand limits

Overview of Futura approach and key inputs

This benefit results from the ability via AMI to scale back the demand of end-user facilities (i.e., households and businesses). At times when demand exceeds supply due to either generation outages or unavailability, or network constraints, this Emergency Supply Capacity Control functionality would allow system operators to scale back supply to a large number of customers thereby sharing the demand reduction in such a way that all or most customers would continue to receive at least some supply.[24] This would also allow "essential infrastructure – such as traffic lights, trains, hospitals, cellular mobile base stations, fire stations, police stations ambulance depots street lights and security lighting"[25] – to keep working.

The premise is that most customers (a) can operate at an at least acceptable level with a reduced level of electricity service, (b) would prefer to do so rather than be cut off entirely, and (c) would be willing to do so to provide that level of safety net for themselves and others. From an aggregate perspective, the ability to avoid total outages for some customers will far outweigh the relatively lower level of inconvenience imposed by the reduced level of supply delivered despite the fact that a much larger number of customers will experience that reduced level of supply.

23 See also our discussion of the counterfactual in Section 4.2.2.

24 In actual practice, any event of this type would almost certainly trigger widespread load shedding. This aspect of AMI functionality would allow power to be restored in short order to almost all customers, though not at a level that would allow all end-use demand to be met.

25 2009 Benefits Report, p 44.

OGW comments

The 2009 Benefits Report calculates the value of this benefit (using an example of a 30% supply deficit) as the difference between the economic impacts of:

- a total outage to 30% of customers, and
- a scaling back of supply by 30% to all customers.

Key inputs to this calculation are:

- the historic level of unserved energy in large-scale disruptions, which Futura Consulting estimates as 3,000 MW for 4 hours,
- the value of customer reliability (VCR)[26] of $47,850 per MWh, and
- an assumption that the (VCR) is non-linear with the amount of demand constraint applied, and that a 30% reduction in demand will result in an 80% reduction in VCR.

We agree with the conceptual framework used in the 2009 Benefits Report for this benefit, but we do not feel the values used for the key inputs are empirically robust:

- The 2009 Benefits Report cites major blackouts in 2009, 2007, 2006, 2005 and 2000. This amounts to one major event in 4 of the past 5 years or 5 such events in the past 10 years. In addition, only one of these events appears to be similar in magnitude to the supply disruption used in the calculation of the benefit value (3,000 MW for 4 hours). As a result, we are not persuaded that the incidence or duration of the conditions required for the level of benefit being claimed is historically justified.
- Further, the events in the historic record include transmission failures. While the functionality being assessed can provide a reduced supply to customers, it cannot do so where transport for that supply is unavailable. This means that in situations where an element of the network is unavailable, customers to whom power cannot be re-routed will still experience a total loss of supply.
- Finally, while we agree that there is almost certainly a non-linear relationship between the share of load lost and the actual VCR, there is simply no empirical or researched basis for the estimate used that VCR is reduced by 80% in response to a 30% reduction in supply.

Revised benefit assessment

Based on the uncertainties discussed above we do not feel that a refined recalculation of this benefit is possible at this point. Consequently we have assigned a zero value to this benefit, a decrease of $422 million.

While we are certain that it is a real benefit with a non-zero value, we think the functionality of being able to apportion supply restrictions across the entire customer base rather than having rolling outages is more reasonably viewed as an insurance benefit that comes at a very modest incremental capital cost to that of the AMI Program.

26 The value of customer reliability is a measure of the economic cost of unserved energy to customers.

4.3.3. Benefit 5: Avoided cost of routine reading (including reductions in costs of PDEs and route management)

Overview

This benefit is comprised of the costs that are no longer incurred for routine meter reading. These costs include the labour and on-costs of the meter reading staff, as well as the equipment they use in their meter reading activities, and the cost of the back-office activities required to process the meter data. Meter reading costs used in the 2009 Benefits Report calculation were taken from the information provided by the distribution businesses to the MCE National CBA study. Back-office processing costs were taken from the ESC's *Electricity Distribution Price Review 2006 - 10, Final Review*.

OGW comments

The assumptions, inputs and methodology used in estimating the value of this benefit are reasonable.

Revised benefit assessment

The value of this benefit is accepted as calculated in the 2009 Benefit Report, except to incorporate an adjustment to account for changes in assumptions with respect to customer numbers, AMI meter numbers and customer number growth rates.

The revised inputs discussed above result in a present value for this benefit of $298 million, an increase of $8 million from the $290 million calculated in the 2009 Benefits Report.

4.3.4. Benefit 9: Avoided cost of manual disconnections and reconnections

Overview

Disconnection and subsequent reconnection of customers' supply is generally required by the serving retailer whenever a customer vacates a premise in order to ensure that the customer is accurately billed for all the electricity he or she has consumed, and to prevent additional electricity from being used at the premise, the wholesale and NUOS cost of which the retailer would be responsible for but for which it would have no contracted customer to bill.

Disconnection and subsequent reconnection is also undertaken by DBs where safety considerations require it, although this occurs much less frequently than customers moving out of and into premises. Non-payment is another infrequent cause of disconnection/reconnection.

Both disconnection and reconnection are currently performed manually. AMI allows these tasks to be conducted remotely, thereby avoiding the labour and transportation costs associated with the manual process. Key inputs to the calculation of the magnitude of cost avoided in the 2009 Benefits Report include:

- the number of disconnections and reconnections undertaken annually,
- the cost per disconnection/reconnection,
- the number of same-day reconnections that currently are not performed on the desired day,
- the amount of delay experienced before reconnection is made,
- the average customer load, and
- the economic impact of late reconnection of affected customers.

OGW comments

The approach taken in the 2009 Benefits Report is quite reasonable, and Futura accurately notes that "in a typical move out situation, the DB's representative will perform two tasks at the premise – final read of the meter (a special read) and disconnection." As the DB makes a single charge for undertaking both of these tasks, their combined avoided cost is taken up in the special reads benefit. This accurately avoids double-counting between these two benefits.[27]

On the other hand, the values used in the 2009 Benefits Report for several of the key inputs are not as appropriate as they could be, and have been revisited. For example:

- The 2009 Benefits Report used a state-wide average of 16.6% of customers requiring disconnection/reconnection annually. This was derived from the actual numbers of these services reported to the MCE study by the Victorian DBs. One DB reported a 7% annual figure at that time, but subsequently reported 29% in its 2010 EPDR. Substitution of that value results in an average state-wide incidence of 22% which has been used in our re-estimate of the value of this benefit.[28]
- The cost per disconnection/reconnection used in the low case benefit estimate of $19.95 is too low. It should be noted that this value is the published charge that the DBs are allowed to levy to customers, but has not been adjusted in over 10 years and as such is almost certainly not the true economic cost of the activity. The EPDR submissions that the DBs have prepared since the time the 2009 Benefits Report was undertaken indicate that the true economic charge is above $30. We believe that $30 is a more accurate value for this charge.
- The 2009 Benefits Report assumed that a same-day reconnection request made at 9AM, if not delivered that day, results in a delay of 8 hours. This was based on the assumption that the reconnection would be completed after-hours on the day of the request. In response to questions we raised on this point Futura personnel stated that "More recent information that has come to light since we undertook the study suggests that the low case time period is too low, and should be closer to 16 to 18 hours". We believe 16 hours is a more appropriate figure.
- The 2009 Benefits Report uses the VCR value of $4.46/kWh to calculate the economic impact of unserved energy due to delayed reconnection. However, that value is actually the contribution of the residential sector to the total volume-weighted state-wide VCR value of $47.85. Given that this benefit is being calculated for the small-volume customers, the vast majority of whom are residential customers, we believe that the residential sector VCR of $13.25 is the more appropriate value to be used in this calculation.[29]

---

27 See discussion of Benefit 6 in Section 4.3.4 above.

28 We note however, that the Australian Bureau of Statistics undertook a survey on mobility of the population, conducted throughout Victoria during October 1999 as a supplement to the Monthly Population Survey. Survey results indicated that "In October 1999 there were 1,014,700 people in Victoria aged 18 years and over who had moved in the previous three years (29%) compared with 2,503,100 people who had not (71%)." [ABS Cat no. 3237.2 - *Population Mobility, Victoria*, Oct 1999.] This number is significantly different from the incidence reported in the DBs' EPDRs. However, as the DB information is more recent and comes from an electricity industry source, we have chosen to use it in preference.

29 See the discussion of the derivation of the residential sector VCR in *Assessment of the Value of Customer Reliability (VCR)*, CRA International Pty Ltd for VENCorp, August 2008, pp 29 - 34.

Revised benefit assessment

The revised inputs discussed above result in the present value of this benefit of $364 million, an increase of $224 million from the $140 million calculated in the 2009 Benefits Report.

4.3.5. Benefit 6: Avoided cost of special reads

Overview

This benefit is comprised of the costs that are no longer incurred for special meter reading. As noted in the 2009 Benefits Report, special reads are most commonly needed when customers move out of a premise. Other conditions in which special reads are required include:

- when a meter reading does not appear to be correct and must be checked;
- upon special request by a customer who is changing retailers: and
- when a meter is changed out.

The 2009 Benefits Report used the specific charge published by each DB for its special read service and multiplied that by the number of special reads undertaken annually by the DBs as reported in the MCE National CBA study.

OGW comments

The methodology used in estimating the value of this benefit is reasonable, but a key input – the cost of conducting the special read – was found to need revision.

The cost of special reads used in the 2009 Benefits Report was based on the published excluded service charges for that service. However, as the 2009 Benefits Report noted, "during the MCE analysis some DBs indicated that the charges for special reads were actually less than the real activity based cost of those reads".[30]

The EPDR submissions that the DBs have prepared since the time the 2009 Benefits Report was undertaken indicate that the true economic charge is above $30. We believe that $30 is a more accurate value for this charge, and have used it in re-calculating the value of this benefit.

Revised benefit assessment

The revised inputs discussed above result in a present value for this benefit of $171 million, an increase of $32 million from the $139 million calculated in the 2009 Benefits Report.

4.3.6. Benefit 19: Reduction in unserved energy (with quicker detection of outages and quicker restoration times)

Overview

Because AMI can detect outages remotely, DBs will be aware of outages more quickly and will also have more precise information about their location and extent. Information on the location and extent of the outage also provides valuable insight into its possible cause(s). These capabilities allow DBs to identify, analyse and rectify outage situations more quickly, thereby reducing unserved energy. The 2009 Benefits Report cites the experience of two US utilities in settling on 6% as the low case estimate for reductions possible in minutes off supply.

30 2009 Benefits Report, p 37.

The 2009 Benefits Report correctly notes that earlier detection of outages will actually initially serve to increase the number of minutes off supply, as it will result in the start time of an outage being identified earlier. However, this is really only a result of an improvement in measurement rather than a decrease in supply availability; the functionality being assessed will still result in real decreases in minutes off supply.

Key inputs to the quantification of this benefit include:

- the degree to which minutes off supply is reduced,
- the volume of energy subject to that improvement in minutes off supply, and
- the value used for the economic impact of unserved energy.

Additional improvements that are likely to result from AMI in regard to quicker restoration of supply include the ability to identify nested outages (considered in Benefit 15 which is discussed later in this report) and the ability to restore power to customers on healthy sections of feeders in the outage-affected area.

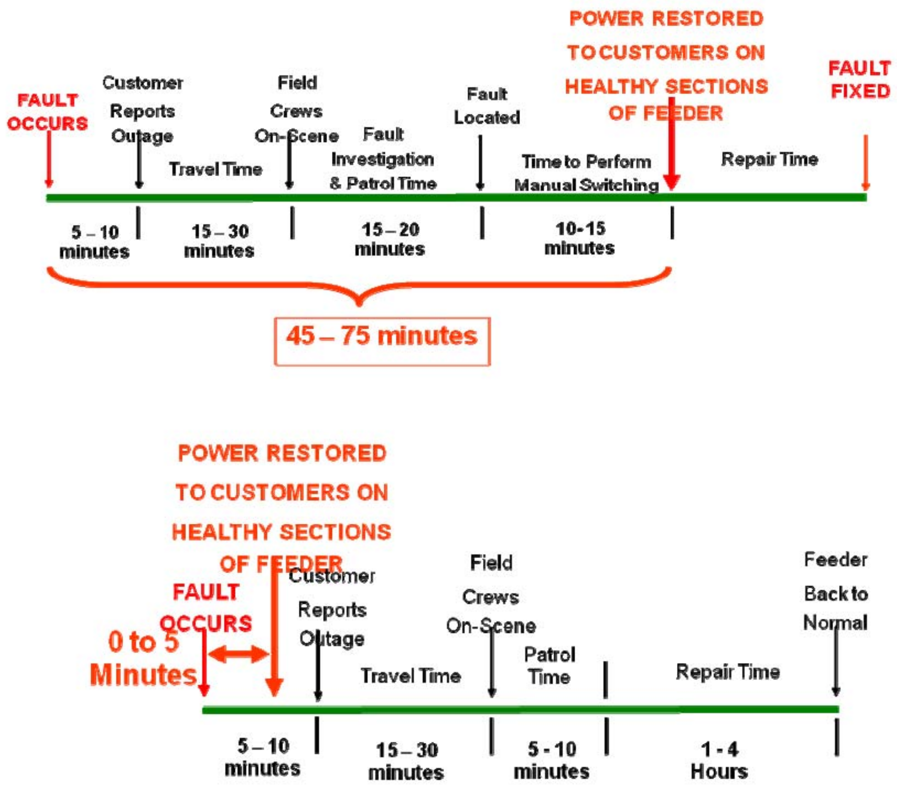
This latter benefit was discussed by United Energy/Jemena at the Smart Metering conference held in Melbourne in February 2010. AMI allows identification[31] of those customers who would have been turned off initially by the fault protection system[32] in response to the fault, but who can actually have their power restored safely. As shown in Figure 1, the time to restore supply to most of these types of customers is substantially reduced from between 45 to 75 minutes to between 0 to 5 minutes. Where there are no line switches present AMI still avoids the initial 5 to 10 minutes.

However, quantification of the benefit provided by this capability would require some estimate of the proportion of customers that are likely to be on healthy sections of outage-affected feeders. As no sufficiently robust information about that proportion is currently available, this benefit cannot be quantified at this time at an acceptable level of accuracy. However, this clearly represents an area of additional benefit potential.

31 Where remotely operated line switches are installed, which is now the case in a high proportion of the network.

32 Which is much less granular in its geographic coverage.

Figure 1: Impact of AMI on fault identification and restoration of power



Source: United Energy/Jemena

OGW comments

The approach taken in the 2009 Benefits Report is quite reasonable. We also agree with the use of the state-wide, volume-weighted average VCR in the calculation.

However, it is our view that the 6% estimate of the degree to which AMI could reduce minutes off supply is likely to be quite conservative. We note first of all that the two US utilities cited in the 2009 Benefits Report are using AMI systems with slower communications capabilities than that specified for Victoria. We also note from the material presented by United Energy/Jemena that AMI can be expected to reduce fault investigation and patrol time from the 15 to 20 minutes it generally takes at present to something between 5 to 10 minutes, indicating a reduction of about 10 minutes on average. Given that it generally takes between 45 and 75 minutes to restore power to most customers, that 10 minute improvement would translate into a reduction of about 16% for these customers.

Based on these considerations we have used 10% as the estimate of the likely reduction in SAIDI due to AMI. This is approximately midway between the experience of the US utilities using somewhat lower specification systems than Victoria's and the 16% estimate that derives from the information presented by United Energy/Jemena.

Two other two inputs used in the calculation of the value of this benefit were also revisited.

- The first was the base used for minutes off supply. The 2009 Benefits Report used the five-year average SAIDI figures in the 2007 DB performance report issued by the ESC. In reviewing the annual data for each DB we noticed that there were significant outlier values for some of the DBs that might skew the results. In response, we recalculated the average SAIDI figure for each DB by removing the high and low value for each DB over the most recent six years for which data is available (2003 through 2008) and taking an average of the remaining four figures. Table 6 compares the SAIDI figures used in the 2009 Benefits Report with those we used in recalculating this benefit.

Table 6: Average SAIDI figures used in the 2009 Benefits Report and this study

DB	Average SAIDI figure (minutes) used in	
	2009 Benefits Report	This review
Citipower	50	40
Jemena	100	106
Powercor	170	185
SPAusNet	245	312
United Energy	80	96

- The other was the volume of energy subject to that improvement in minutes off supply reduction. The 2009 Benefits Report based the benefit on the reduction in USE for customers who currently have non-interval meters, and therefore used the annual energy represented by the Net System Load Profile (NSLP). Our view is that this benefit is a product of both the smart meters and the communications that will be installed under the AMI Program. We further note that once the two-way communications system is in place, it is likely that the interval meters that are currently installed in the facilities of larger end users will be retrofitted or replaced to allow them to use that communications system also.[33] Once this is the case, this AMI functionality will provide an improvement in the minutes off supply of these customers as well. Therefore, we believe that the total system profile is the appropriate volume to be used as the base for reductions in USE due to this AMI functionality.

Revised benefit assessment

The revised inputs discussed above result in a present value for this benefit of $375 million, an increase of $249 million from the $126 million calculated in the 2009 Benefits Report.

33 Note that Benefit 27 assumes that these customers will be migrated to the AMI system.

4.3.7. Benefit 31: Energy conservation from three-rate TOU tariff

Overview

Interval metering supports the introduction of more time-differentiated and cost-reflective price signals. The 2009 Benefits Report cites experience in NSW and Queensland that it feels suggests that three-rate time-of-use tariffs are likely to become widespread following the rollout of interval meters to the mass market. A brief summary of this experience includes the following:

EnergyAustralia Network has installed over 400,000 interval meters for mass market customers and has placed these customers on a three part time-of-use tariff. According to EnergyAustralia's submission to the AER, the purpose of the tariff is to influence customers to "reduce overall demand or shift demand from peak to shoulder periods". EnergyAustralia Retail and at least some second tier retailers have mirrored these tariffs in their offers to customers. The 2009 Benefits Report speculates that it may even be the case that it is difficult for customers who have been put on a TOU network tariff to obtain flat tariff offers from retailers at this point. [34]

In Queensland, retailers and DBs have made submissions to the QCA that "retailers should be allowed to pass through network charges in their retail pricing to consumers, and that retail tariff structures should have flexibility to allow the network charges to be passed through, whatever might be the structure of the network tariffs".[35]

Based on these developments, the 2009 Benefits Report concludes that three-part TOU tariffs are likely to become very widespread and for the purpose of calculating the value of this benefit, assumes in its low case valuation that 80% of mass-market customers will be moved to this type of tariff structure upon installation of their interval meters, and will then stay on that tariff.

The 2009 Benefits Report cites experience in overseas electricity markets that suggest that annual electricity consumption reduces by anywhere from 3% to 6% when customers are put on TOU tariffs. Based on somewhat lower results in trials of TOU tariffs in Australia, the 2009 Benefits Report uses a 1.5% reduction in electricity consumption as its estimate of the impact of these tariffs in its low case assessment.

The other key input to the calculation of the value of this benefit is the value of the electricity saved due to the tariff. The 2009 Benefit Report suggested that this is in the range of 40% to 50% of the retail tariff price.

OGW comments

We agree with the approach taken in the 2009 Benefits Report to calculating this benefit, but have significant reservations about the level of penetration of the TOU tariff that has been assumed.

The 2009 Benefits Report states: "It makes sense that retailers want to pass through network charges to customers, so that they have cost-reflective tariffs that can match their revenues to costs on an individual customer basis. On that basis, in Victoria, where retailers can choose their tariff structures and pricing levels without prior Government or regulatory approval, we expect that retailers will match network TOU tariffs with corresponding retail TOU tariffs".[36]

---

34 As reported in the 2009 Benefits Report, p 69.

35 Ibid

36 Ibid

We do not find it surprising that retailers may want to pass through a new structure of network tariffs, given that they do not have accurate information at present about the daily load profile of their mass-market customers, and have no way to hedge the volume risk of that profile to a time-differentiated network price.

However, we believe that such pass-through is likely to be a transitional, at least for a significant segment of the mass-market customers. Our view on this is informed by the fact that risk management is a core skill of retailers, and a key benefit they offer customers and on which they earn their income. It is also the case that at present there is a significant segment of the customer base that prefers a static price for electricity. While it is logical for retailers to seek to avoid accepting a risk they do not fully understand and cannot hedge, the rollout of interval metering will provide them with a significant amount of information about the daily and seasonal load profiles of their mass-market customers. This information is likely to be sufficient for retailers to calculate the likely proportion of a customer's consumption that will take place in each time period and provide a weighted flat price, which will include an appropriate risk premium. It is important to note that the fact that the network TOU price signal is static, meaning that the retailer does not face price risk, only volume risk. This makes the development of a flat price based on an observed load profile significantly easier.

Based on these considerations we believe the 80% penetration for TOU used in the 2009 Benefits Report is significantly too high, particularly over the longer term. As suggested above, we agree that TOU tariffs may experience high take-up initially, but we also feel that this is likely to be eroded relatively quickly. Although there is no empirical basis for projecting the long term penetration of TOU tariffs, 80% is a very high penetration in a market where choice is available. For example, the retailer could protect itself completely from the risk posed by a TOU network price signal by simply passing that price signal along to the customer, while continuing to provide a flat price for the wholesale energy and retail cost components of the tariff. This would be very similar to what retailers do for larger customers, and would significantly blunt the time differentiation of the price at the end user level which would also be expected to reduce its load-shifting and conservation impact.

Based on these considerations, we propose 30% as the long-term penetration of the TOU tariff. As noted above, there is no empirical base for this estimate, but it is still a significant level of penetration and provides a more conservative estimate of the value of this benefit.[37]

We also reviewed the input used for the economic value of the energy that would be saved by the TOU tariff. The 2009 Benefits Report appears to have estimated this input as 40% of an average retail tariff level of $0.16/kWh.[38] As a check of this value we assumed that the marginal plant during peak periods is most likely to be OCGT. The SRMC of these plants is in the order of 7 to 8 cents/kWh, which is a bit higher than the value used in the 2009 Benefits Report.

37 We also acknowledge the fact that the premium that the retailer would add to provide a flat price would provide head room for competing retailers offering a TOU price. However, we also note that the lowest price does not garner all the customers in the mass market, as evidenced by the fact that approximately 40% of residential customers in Victoria were still on regulated tariffs as at 1 January 2007, five years after lower-priced market offers were available and delivered to their doorsteps. (See *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in Victoria*, First Draft Report, Australian Energy Market Commission, 4 October 2007.)

38 This was confirmed in correspondence dated 12 April from one of the authors of the 2009 Benefits Report, but does not appear in the document itself.

Revised benefit assessment

The revised inputs discussed above result in a present value for this benefit of $49 million, a decrease of $74 million from the $123 million calculated in the 2009 Benefits Report.

4.3.8. Benefit 7: Avoided cost of time switch replacement and O&M

Overview

Time switches are used in Victoria to control off-peak water heaters and some other end-use appliances. This control is meant to allow the appliance to operate in off-peak hours only, and thereby be charged at a special discounted rate. Because the time switches are mechanical devices they can drift, and in some cases may be tampered with. Information from the DBs indicates that they re-set approximately 2% of the 549,000 time switches each year.

Because AMI can perform the same function these switches provide, and can be reset without requiring a site visit, they offer the potential to essentially eliminate the costs currently incurred by the DBs in resetting these switches.

OGW comments

The assumptions, inputs and methodology used in estimating the value of this benefit are reasonable.

Revised benefit assessment

The value of this benefit is accepted as calculated in the 2009 Benefit Report, except to incorporate an adjustment to account for changes in assumptions with respect to customer numbers, AMI meter numbers and customer number growth rates.

The revised inputs discussed above result in a present value for this benefit of $99 million, an increase of $6 million from the $93 million calculated in the 2009 Benefits Report.

4.3.9. Benefit 29: Avoided network and generation augmentation from peak demand reduction from three-rate TOU network tariff introduction and resultant three-rate retail tariff

Overview

The nature of this benefit and how its value was determined is very similar to that of Benefit 31 discussed above. Where Benefit 31 assessed the economic value of the electricity saved by the impact of the three-part TOU tariff, this benefit values the reduction in peak demand produced by the tariff.

As in the case of Benefit 31, the 2009 Benefits Report cited international and Australian experience in settling on 2% as the low case reduction in peak demand due to the tariff.

OGW comments

As discussed in regard to Benefit 31 we believe the 80% penetration of TOU assumed by the 2009 Benefits Report is too high, and have preferred to use 30% as a more realistically conservative estimate.

Three other inputs to the 2009 Benefits Report calculation were also revised in our review:

- The 2009 Benefits Report used $130/kW/year as the value of avoided peak demand in the low case and $240/kW/year in the high case. We believe that the low case value significantly understates the value of peak demand reductions. It approximates the deferral value of generation capacity (that is the annualised capital cost of OCGT plant), but therefore entirely ignores the value of deferring augmentation of network infrastructure. We believe a value of $200/kW/year is a more accurate estimate of the combined deferral value of generation and network infrastructure. We note that the 2009 Benefits Report used a value of $240/kW/year as the combined deferral value of generation and network infrastructure.[39] We do not dispute the use of $110/kW/year (or even a higher figure) as an approximation of the long-run cost of network augmentation. However, we also note that investments in network infrastructure – and particularly at the distribution level – are lumpy, time-sensitive and highly localised. Because of this we believe it is more realistic to use a somewhat discounted value for the long-run marginal cost of network capacity, reflecting the fact that not every kW in reduced end-use demand necessarily translates into a reduction of network capacity requirement.
- A more minor correction was the substitution of 9,818 MW from AEMO's 2009 ESOO for the figure of 10,345 MW used in the 2009 Benefits Report as base year (2007-08) summer peak demand in Victoria.

Revised benefit assessment

The revised inputs discussed above result in a present value for this benefit of $44 million, a decrease of $45 million from the $89 million calculated in the 2009 Benefits Report.

4.3.10. Benefit 34: Additional demand response from direct load control of air conditioners

Overview

Direct load control (DLC) of air conditioners can be provided by AMI augmented by a home area network (HAN). DLC uses the capabilities of the home area network to cycle the compressor or the entire operation of the air conditioner during periods of high demand or high price to reduce the coincident demand of these end-use devices. The on/off cycling proportions are determined to ensure amenity levels do not materially deteriorate.

Historically, DLC has been marketed overseas with either rebates or a discounted tariff, but it can also be used in combination with innovative pricing signals, such as time of use (TOU) tariffs or critical peak pricing (CPP). In estimating the benefit of DLC, the 2009 Benefits Report assumed that it would be used in conjunction with a TOU tariff. The 2009 Benefits Report cites the results of DLC trials that have been conducted in Australia (without any price signals) to establish that DLC can reduce air-conditioning peak demand by 19%. The 2009 Benefits Report also cites US experience that indicates that DLC used in combination with CPP can produce an incremental reduction of 6% of total household peak demand.

The 2009 Benefits Report also assumes that take-up rate of DLC will be 10% of the residential customer base.

39 This figure was also used in the MCE's 2007-08 National CBA study.

OGW comments

We accept as reasonable the estimated take-up rate and peak demand reduction impact of DLC as posited in the 2009 Benefits Report. We note that DLC can be used on its own, or in combination with TOU or CPP. It is not realistic, however, to try to guess the relative take-up of DLC in these various combinations, and therefore accept the simplified assumption on which the 2009 Benefits Report estimate is based.

However, there was one other input to the calculation of the value of this benefit that we felt could be improved. This was changing the value of avoided generation and network augmentation from the $130/kW/year that was used in the 2009 Benefits Report to $200/kW/year, as discussed in relation to Benefit 29 above.

Revised benefit assessment

The revised inputs discussed above result in a present value for this benefit of $113 million, an increase of $28 million from the $85 million calculated in the 2009 Benefits Report.

4.3.11. Benefit 30: Avoided network and generation augmentation from peak demand reduction from CPP tariff implementation

Overview

As mentioned earlier, interval metering allows the introduction of innovative pricing. One such pricing signal that has received significant attention from utilities in jurisdictions that have deployed AMI is critical peak pricing (CPP). Under a CPP regime, very high published prices are declared generally on a day-ahead basis when periods of extremely high demand and high marginal prices are forecast. The number of critical peak price days that can be declared in a year, season and/or month is generally limited as a condition of the tariff, and there are sometimes limits on the number of consecutive days that can be declared as critical peak price days. In some applications the hours of the day over which the critical peak price will be in force is fixed; in other applications the hours can vary but are often capped to a maximum number of hours per event.

Critical peak pricing has been used in Australia and overseas by both network and retail companies, and it is likely that a network CPP would pose significantly higher risks to retailers than would a network TOU tariff, as it transfers both volume and price risk to the retailer. As a result, a network CPP tariff is potentially more likely to be passed through to customers than a network TOU tariff.

The 2009 Benefits Report cites documented international and Australian experience in setting 15% as the estimated reduction in peak demand due to CPP. This value is consciously lower than the impacts achieved in Australian and US trials in recognition of the fact that CPP may be implemented in combination with TOU, with the reduced impact value having been chosen to avoid double counting of the benefit.

The 2009 Benefits Report also posits a 12% take-up rate for the CPP tariff.

OGW comments

We accept the estimate used in the 2009 Benefits Report for the impact of CPP on peak demand. It seems possible to us that the take-up rate could be higher than 12% but accept the value used in the 2009 Benefits Report as a conservative value.

We have revised the inputs used for the economic value of avoided generation and network infrastructure augmentation. Specifically, we have used $200/kW/year instead of $130/kW/year as the economic value of avoided generation and network infrastructure augmentation.

We have also revised the assumption regarding the schedule on which this benefit will be revised. We believe that these benefits would accrue progressively as the rollout takes place because, to the extent that retailers are likely to want to use CPP it is reasonable to assume that they would want to conduct market tests to refine their marketing approaches and pricing, and to become comfortable with the technical operations involved. This argues for early and progressive deployment and use of this functionality, rather than waiting to use it until the rollout of the AMI infrastructure was completed.

A more minor correction was the substitution of 9,818 MW from AEMO's 2009 ESOO for the figure of 10,345 MW used in the 2009 Benefits Report as base year (2007-08) summer peak demand in Victoria.

Revised benefit assessment

The revised inputs discussed above result in a present value for this benefit of $133 million, an increase of $60 million from the $73 million calculated in the 2009 Benefits Report.

4.3.12. Benefit 38: Revenue from reading smart water meters for water utilities

Overview

The 2009 Benefits Report states that "the Victorian water utilities together with the Department of Sustainability and Environment (DSE) have been exploring means to remotely read water meters and also to be able to provide customers with information about real time consumption of water on IHDs".[40] It then assumes that the meters would use the same communications system as the electricity AMI and that the water utilities would pay the electricity DBs $3 per water meter per read.

OGW comments

We do not question whether this would be cost-beneficial for the water utilities or the amount that might be charged. We do note, however, that the $3 figure is not a benefit but merely a transfer of revenue from the water utilities to the electricity DBs. Whether that amount represents a net benefit depends upon the cost of reading the water meters without AMI, and the other benefits and costs associated with AMI for water meters.

The fact that any fixed or joint costs of the communications system are at present fully allocated to the electricity AMI cost benefit assessment is another matter. If the water AMI case is actively being considered in the same way that the electricity AMI case is, there might be grounds for apportioning the fixed and/or joint costs of the communications systems between the two assessments. Without firm information on the status of the water AMI case the conservative course of action is to take up the full cost of the communications system in the electricity AMI case.

Revised benefit assessment

Because the revenue the electricity DBs would receive from the water utilities for meter reading is a transfer rather than a benefit, this benefit value has been removed.

40 2009 Benefits Report, p 87.

4.3.13. Benefit 35: Energy conservation from IHDs

Overview

The 2009 Benefits Report cites a trial by Integral Energy and numerous overseas studies as the basis for assuming that in-home displays (IHDs) – devices that display information about various aspects of an end-user's electricity consumption in real time and for selected cumulative periods – can reduce energy consumption by anywhere from 1.2% to 15%.

As inputs to its estimate of the low case benefit of additional energy conservation from IHDs, the report assumes that these devices will be taken up on a voluntary basis (at a cost of $100 each) by 7.5% of customers who will then reduce their consumption by 6% on average. This relatively high average level of savings was justified by Futura on the basis that the first tranche of IHD adopters would be likely to be highly motivated individuals.

OGW comments

The approach and inputs used in the 2009 Benefits Report seems reasonable. We note that while the report assumed that the 'early adopters' of IHDs would be likely to be relatively highly motivated towards energy conservation (a point we agree with), it did not assume that this market segment would have anything other than average per household energy consumption. This seems to us to be a conservative assumption, but as no better information is available, we have accepted it.

Revised benefit assessment

The value of this benefit is accepted as calculated in the 2009 Benefit Report, with revision limited to incorporation of the revised general economic and market assumptions that were subsequently taken up to ensure consistency between the 2010 Cost Report, the 2009 Benefits Report and this report.

The revised inputs discussed above result in a present value for this benefit of $50 million, an increase of $1 million from the $49 million calculated in the 2009 Benefits Report.

However, we note that a number of trials and studies of other types of information provision have been undertaken and indicate that other forms of information can also produce energy conservation using information from 'smart meters'. Because of this we have added a benefit category (see the discussion of Benefit 35a immediately following).

4.3.14. Benefit 35a: Energy conservation from enhanced information

Overview

As noted above, a number of trials and studies of other types of information provision have been undertaken and indicate that other forms of information can also produce energy conservation using information from 'smart meters'. Because of this we have added this benefit category which did not appear in the 2009 Benefits Report.

OGW comments

The 2009 Futura Report discussed the potential for additional demand response and energy conservation effects from the provision to customers of information on their energy use. While some of these benefits are captured by Benefit 35 (IHD), it is expected that only a minority of all consumers will take up IHDs (7.5% in the low case).

Therefore, there remains significant scope to provide lower cost forms of information to the much larger segment of customers who are not expected to take up IHDs. One of the most effective forms of information for motivating consumers to alter their energy consumption behaviour is comparative feedback information, whereby a household's energy use is compared or benchmarked against a peer group (e.g., a group of households with similar characteristics).

Several evaluations of recent comparative feedback programs in the US illustrate the potential of such an approach. The Sacramento Municipal Utility District (SMUD) has been running a comparative reporting program for 16 months involving 35,000 households. These households receive regular reports (separate to their bill) that compare their current energy use to that of their neighbours, and suggest actions they can take to reduce their energy consumption. A recent evaluation of the program comparing the energy consumption of the households receiving these reports against a control group found that:

- participating households reduced their electricity consumption by an average of 2.2% in the first year, with impacts increasing over the first four months of the second year to 2.8%;
- participating households reduced their 2009 summer season energy consumption by 3.5%; and
- these impacts were consistent across all major demographic segments.[41]

There are limited results available at this time regarding the load reduction impacts of comparative benchmarking at time of system peak, although we understand such evaluations are currently underway. The reports cost about US$10 per house per year for production, handling, and mailing. Similar data to the hardcopy reports could be presented to consumers via an online portal, which would have material development and set-up costs but very low on-going operating costs.

The average energy consumption of households in the SMUD trial is estimated to be 30 to 40% higher than the average Victorian household consumption, and therefore it would be reasonable to expect lower impacts in Victoria. Based on these results, we have assumed energy savings of 1.0% per annum due to the provision of this sort of information. We have also assumed that 70% of residential customers would use this information source.

Revised benefit assessment

Based on the assumptions above, this functionality would produce a benefit with a present value of $44 million, all of which is incremental to the benefits calculated in the 2009 Benefits Report.

4.3.15. Benefit 8: Avoided additional cost of energy from time switch clock errors

Overview

As stated in the 2009 Benefits Report, "There is a proportion of time switches which for various reasons are no longer switching their loads on during off peak hours (often between 11pm and 7am), but rather are switching on during peak hours. This results in consumption occurring during the peak times but charged at off peak rates".[42] The report cites surveys indicating that this may be the case for approximately 5% of the 549,000 time switches in place in the state.

---

41 See Summit Blue, Independent Evaluation of Opower SMUD Pilot Project, Sep 2009, and Ayres et al, Evidence from Two Large Field Experiments that Peer Comparison Feedback Can Reduce Residential Energy Use, Aug 2009.

42 Ibid, p 39.

Because AMI would ensure accurate time switching of these loads it would avoid them operating outside the off-peak period and would therefore avoid the higher cost of electricity which pertains at other times.

OGW comments

We accept the incidence of this problem as cited in the 2009 Benefits Report, and the fact that correct functioning of these time switches would result in a benefit associated with the avoided cost of energy consumed outside the off-peak period.

However, we note that correct operation of these switches would also avoid some level of peak demand. In conversation Futura Consulting stated that information they have indicates that 5% to 10% of the time switches are at least 8 hours off schedule, and are therefore operating outside the off-peak period.

In estimating the magnitude of avoided peak demand that would result from correcting the operation of these time switches (noting that AMI would prevent further re-setting of the operating time by end users) we have used the following assumptions:

- The actual distribution of times that the faulty time switches allow their loads to come on is unknown. It could be assumed that their 'start' times are uniformly distributed across the peak hours of 7AM to 11PM. To simplify calculations we have assumed half will operate between 7AM to 3PM and the other half between 3PM and 11PM;
- The water heaters that operate between 7AM and 3PM have no impact on peak demand (which occurs at between 5PM and 6PM) because they have switched off by then;
- The water heaters that operate between 3PM and 11PM do have some impact on peak demand, calculated as follows:
  - the average capacity rating of a water heater is assumed to be 4.5kW
  - the average water heater of the size used on a controlled tariff will fully recharge in about 2 to 3 hours
  - a coincidence factor of 10%, which is estimated based on the fact that some of the water heaters will be below their set point temperature when operation commences at 3PM, and some will experience draw between 3PM and 6PM that will introduce cold water into the tank that will cause the heating element to turn on
  - an annualised capital charge of $200/kW/year as the value of avoided peak demand as described previously.

Calculations based on these assumptions result in a reduction in peak demand of 6.2MW worth $1.2 million per year.

In addition, we revised several of the input assumptions used in the calculation of the value of avoided energy costs as undertaken in the 2009 Benefits Report. These included:

- The 2009 Benefits Report assumed that the difference between on-peak and off-peak energy costs are $70 per MWh. We note that the load weighted average cost of electricity consumed in the relevant periods in 2008 was as follows:
  - 11PM to 7AM: $26.56 per MWh
  - 7AM to 3PM: $46.41 per MWh
  - 3PM to 11PM: $54.65 per MWh.

Using these prices, the 50/50 split of usage into the two non-off-peak periods described previously and the estimate that controlled water heaters use 2,500 kWh per year on average, the value of the avoided energy costs comes to $1.6 million per year.

Revised benefit assessment

Based on these re-calculations the present value of the benefit of this functionality of AMI has been estimated as $41 million, a reduction of approximately $7 million from the $48 million estimated in the 2009 Benefits Report.

4.3.16. Benefit 14: Avoided cost of investigation of customer complaints about voltage QoS, including equipment cost and cost of reporting to regulator

Overview

This benefit results from the ability of AMI to provide information on the quality of supply at the end-use customer level. The availability of this data allows DBs to answer customers' questions about voltage levels and other quality of supply issues without site visits and the need to install special equipment to record site-specific data and then subsequently analyse that data.

By contrast, smart metering functionality monitors the voltage that is provided to the customer on a continuous basis, and can therefore identify exactly when dips and spikes occur. It also records information on outages, including the date, time and duration of their occurrence. The availability of this information allows the distribution company to answer customers' questions and determine whether corrective actions are required much more quickly, and avoids the needs for site visits, the placement of special equipment, and subsequent data analysis.

OGW comments

The assumptions, inputs and methodology used in estimating the value of this benefit are reasonable.

Revised benefit assessment

The value of this benefit is accepted as calculated in the 2009 Benefit Report, except to incorporate an adjustment to account for changes in assumptions with respect to customer numbers, AMI meter numbers and customer number growth rates.

The revised inputs discussed above result in a present value for this benefit of $39 million, an increase of $1 million from the $38 million calculated in the 2009 Benefits Report.

4.3.17. Benefit 37: Avoided cost of other communications to manage customers' loads for renewable generation tracking, electric vehicle charging and local generation management

Overview

This benefit is comprised of the avoided communications costs that would be required in the absence of AMI to effectively manage the impact of the re-charging of electric vehicle batteries on the grid. Given the size of these batteries, it is more than possible that the uncontrolled demand of these devices, even at relatively modest penetration levels of electric vehicles, could cause new network system peaks, thereby increasing the capex requirement of the network.

The communications system that is part of AMI would provide this communications capability at no incremental cost.

OGW comments

The assumptions, inputs and methodology used in estimating the value of this benefit are reasonable.

Revised benefit assessment

The value of this benefit is accepted as calculated in the 2009 Benefit Report, except to incorporate an adjustment to account for changes in assumptions with respect to customer numbers, AMI meter numbers and customer number growth rates.

The revised inputs discussed above result in a present value for this benefit of $35 million, an increase of $1 million from the $34 million calculated in the 2009 Benefits Report.

4.3.18. Benefit 1: Avoided costs of installing import / export metering

Overview

This benefit arises from the ability of smart meters to record electricity flows into and out of a premise (that is, in either direction through the meter). This functionality will allow net metering of customer installations of PV, wind and other on-site generation systems without additional metering equipment. It is the avoided cost of such equipment and the number of such customer on-site generation installations that are likely to take place that comprises the value of this benefit.

OGW comments

The assumptions, inputs and methodology used in estimating the value of this benefit are reasonable.

Revised benefit assessment

The value of this benefit is accepted as calculated in the 2009 Benefit Report, except to incorporate an adjustment to account for changes in assumptions with respect to customer numbers, AMI meter numbers and customer number growth rates.

The revised inputs discussed above result in a present value for this benefit of $35 million, an increase of $2 million from the $33 million calculated in the 2009 Benefits Report.

4.3.19. Benefit 36: Peak demand reduction through deferral of refrigerator auto defrost cycle out of peak period

Overview

This benefit results from the fact that 'smart' refrigerators are being developed that, among other things, provide the capability for their defrost cycle to be constrained off. The HAN functionality of AMI can allow this constraint to be applied during periods of high electricity prices and/or supply constraint.

The most important variables for assessing the value of this benefit are: the rate and total market penetration of refrigerators with this capability, the proportion of refrigerators whose defrost cycle would occur at times of peak demand in the absence of this capability (coincidence factor), and the capacity rating of the defrost element and defrost operating cycle of the average refrigerator.

OGW comments

The assumptions, inputs and methodology used in estimating the value of this benefit are reasonable.

Revised benefit assessment

The value of this benefit is accepted as calculated in the 2009 Benefit Report, except to incorporate an adjustment to account for changes in assumptions with respect to customer numbers, AMI meter numbers and customer number growth rates.

The change to the value of this benefit was less than half a million dollars.

4.3.20. Benefit 27: Reduction in MDA costs – putting I&C customers on DB AMI networks

Overview

Once AMI is in place it will allow the meters data of larger customers (those with annual consumption greater than 160 MWh) to be collected via the AMI communications system at no additional capital cost and an incremental annual cost of $40 to $60. The data from these meters is currently communicated back the meter data agents meter from these via GSM/GPRS technology at an annual cost of about $350 per meter. The difference between those two sets of annual costs represents the benefit provided by AMI.

OGW comments

The assumptions, inputs and methodology used in estimating the value of this benefit are reasonable.

Revised benefit assessment

The value of this benefit is accepted as calculated in the 2009 Benefit Report, except to incorporate an adjustment to account for changes in assumptions with respect to customer numbers, AMI meter numbers and customer number growth rates.

The revised inputs discussed above result in a present value for this benefit of $26 million, an increase of $1 million from the $25 million calculated in the 2009 Benefits Report.

4.3.21. Benefit 22: Avoided cost of proportion of transformer failures on overload

Overview

Transformers can fail when overloaded. AMI would allow the load on each transformer to be monitored in real time as the summation of the load at end premise served by that transformer. In situations where the summed load approaches the overload limit of the transformer, the emergency supply capacity limit functionality of AMI could be used to prevent transformer overload failure. This benefit is comprised of the avoided cost of transformer replacements that could result from this functionality, based on the number of transformer overload failures that occur in Victoria in a typical year (excluding failures due to phase imbalances).

OGW comments

The assumptions, inputs and methodology used in estimating the value of this benefit are reasonable.

Revised benefit assessment

The value of this benefit is accepted as calculated in the 2009 Benefit Report, except to incorporate an adjustment to account for changes in assumptions with respect to customer numbers, AMI meter numbers and customer number growth rates.

The revised inputs discussed above result in a present value for this benefit of $28 million, an increase of $8 million from the $20 million calculated in the 2009 Benefits Report.

4.3.22. Remaining benefits

As mentioned previously, the remaining 18 benefits account for less that 5% of the aggregate benefit value calculated in the 2009 Benefits Report. These benefits, in descending benefit value order, are:

- Benefit 17: Avoided cost of investigation of customer complaints of loss of supply which turn out not to be a loss of supply
- Benefit 16: Reduction in calls to faults and emergencies lines
- Benefit 32: Energy conservation from CPP tariff implementation
- Benefit 15: Reduced cost for post-storm supply restoration – avoided delays in detecting and correcting nested outages
- Benefit 24: Reduction in energy trading costs through improved wholesale forecasting accuracy
- Benefit 26: Customer benefit of being able to switch retailer more quickly and more certainly
- Benefit 3: Reduced testing of meters
- Benefit 4: Reduced cost of network loading studies for network planning
- Benefit 10: Avoided cost of setting demand limits for customers to promote fair sharing and defer augmentation capex
- Benefit 13: Avoided cost of replacing service fuses that fail from overload
- Benefit 21: Avoided cost of proportion of HV/LV transformer fuse operations on overload
- Benefit 23: Reduction in calls related to estimated bills and high bill enquiries
- Benefit 12: Avoided cost of supply capacity circuit breaker
- Benefit 18: Avoided cost of end-of-line monitoring
- Benefit 33: Additional demand response from IHDs on CPP
- Benefit 20: Avoided cost of communications to feeder automation equipment
- Benefit 25: Reduction in the administration cost of bad debt incurred on non-payment on move outs
- Benefit 28: Ability for customers to move to monthly billing on the basis of electronic bills, reducing admin costs, collection costs etc.

These benefits were not examined in detail, with the following exceptions which were reviewed because the range identified between their low and high case benefits in the 2009 Benefits Report suggested that they might represent a material contribution to aggregate benefits if the high case benefits were found to be more representative of their likely outcomes:

- Benefit 15: Reduced cost for post-storm supply restoration – avoided delays in detecting and correcting nested outages
- Benefit 24: Reduction in energy trading costs through improved wholesale forecasting accuracy
- Benefit 32: Energy conservation from CPP tariff implementation.

However, after review of the calculation of these benefits we found no reason to amend either the methodologies or benefit-specific data inputs used in the 2009 Benefits Report.

As a result, we have accepted the benefit values put forward for the final 18 benefits as calculated in the 2009 Benefit Report, except to incorporate adjustments where appropriate to account for changes in assumptions with respect to customer numbers, AMI meter numbers and customer number growth rates.

4.4. Summary of revised low case benefit assessment

4.4.1. Overall results

The 2009 Benefits Report calculated the present value of the benefits of AMI under its low case assumptions as $2.481 billion (2008$).

Based on the review we have undertaken, we estimate those benefits at $2.577 billion (2008$). The $96 million difference between the two studies is the result of two sources of change:

- changes which were made to the general economic and market assumptions in order to ensure consistency between the cost and benefit information used in the benefit/cost report that is presented in a separate report;
  - these changes resulted in a net addition of approximately $84 million to the present value of the AMI benefits; and
- changes made to the data inputs used in specific benefit calculations;
  - these changes resulted in a net addition of approximately $12 million to the present value of the AMI benefits.

The changes that were made to the data inputs used in specific benefit calculations resulted in some benefits increasing in value and others decreasing. More specifically, these changes

- Decreased the present value of five benefits by a total of $618 million
  - Of these, the value of two benefits were reduced to zero:
    - Benefit 11, *Ability to set emergency demand limits to share limited supply at times of network stress or supply shortage* – was reduced to zero because the input data assumptions on which the benefit calculation in the 2009 Benefits Report was not felt to be sufficiently robust. It should be noted, however, that we strongly believe that this is a real benefit with a non-zero value, but one that, at this point, may be better thought of as an insurance benefit, rather than a benefit that will deliver monetary value within any specific timeframe.
    - Benefit 38, *Revenue from reading smart water meters for water utilities* – was reduced to zero because this revenue is a transfer, not a net benefit.
  - The value of three other benefits were reduced by between 23% and 60%; these included:
    - Benefit 8, *Avoided additional cost of energy from time switch clock errors* – was reduced by $11 million (23%) due to the net effect of the value of avoided energy costs having been over-estimated, and the value of avoided generation and network augmentation having been omitted in the 2009 Benefits Report;
    - Benefit 29, *Avoided network and generation augmentation from peak demand reduction from three-rate TOU network tariff introduction and resultant three-rate retail tariff* – was reduced by $45 million (51%) due to the net effect of our view that the take-up rate of 80% that had been assumed was significantly too high, and the value of avoided augmentation costs having been too low;

- Benefit 31, *Energy conservation from three-rate TOU tariff* – was reduced by $74 million (60%) due to the same factors discussed with regard to Benefit 29 immediately above.

- Increased the value of six benefits and identified and quantified one additional benefit that in total added $629 million in present value
  - The six benefits whose values were increased were:
    - Benefit 6, *Avoided cost of special reads* – was increased by $25 million (18%) because the cost of conducting a special read had been under-estimated;
    - Benefit 9, *Avoided cost of manual disconnections and reconnections* – was increased by $219 million (156%) due to corrections (increases to each of the following inputs: the avoidable cost of the service, the number of disconnects and reconnects performed in an average year, and the amount of unserved energy that would be avoided; and the use of a more appropriate value (which was higher than the value that had been used in the 2009 Benefits Report) for the unserved energy avoided by this functionality;
    - Benefit 19, *Reduction in unserved energy (with quicker detection of outages and quicker restoration times)* – was increased by $247 million (196%) because the base SAIDI figures and load on which the value of this benefit had been calculated had been underestimated, and the impact of this functionality on SAIDI was revised upwards based on further analysis of available overseas information;
    - Benefit 22, *Avoided cost of a proportion of transformer failures on overload* – was increased by $7 million (35%) because the reduction in unserved energy provided by this benefit had not been accounted for;
    - Benefit 30, *Avoided network and generation augmentation from peak demand reduction from CPP tariff implementation* – was increased by $60 million (82%) because the value of avoided generation and network augmentation used in the 2009 Benefits Report was too low, and we felt that the benefit would accrue more quickly than assumed in the 2009 Benefits Report; and
    - Benefit 34, *Additional demand response from direct load control of air conditioners* – was increased by $26 million (31%) for the same reasons as discussed with regard to Benefit 30 immediately above.
  - We estimated the value of the benefit that could be obtained due to the additional information that could be provided to consumers due to AMI regarding their energy use. The value of this capability was estimated at $44 million in present value terms based on the results of efforts of this type that have been undertaken overseas.

The net effect of these changes – increases in the value of individual benefits and the inclusion of a new benefit totalling $629, decreases in others totalling $618 million, and relatively modest increases to a large number of the benefits due to adjustments in three of the general economic and market assumptions used in the calculations which added $84 million – resulted in total benefits of $2,577 million, which is $96 million higher than the $2,481 million that had been calculated in the 2009 Benefits Report.

Table 7 below shows the changes that have resulted in the estimate of AMI benefits from the review undertaken of the 2009 Benefits Report. The table lists the benefits in order of their benefit number in the 2009 Benefits Report, and separates the impacts of the changes made to general economic and market assumptions from those made to particular data inputs to specific benefits.

Table 7: Comparison of benefit values from 2009 Benefits Report (low case) and the low benefit values from this review

Benefit No	Benefit	Value (2008$ M[43]) in		Amount (2008$ M[38]) due to change in		Most significant benefit-specific changes[44]
		2009 Benefits Report (low)	OGW Review[45] (low)	General economic and market assumptions[46]	Benefit-specific inputs[47]	
1	Avoided costs of installing import / export metering	33	35	2	0	
2	Avoided costs of meter replacement	455	492	37	0	
3	Reduced testing of meters	7	7	0	0	
4	Reduced cost of network loading studies for network planning	5	5	0	0	
5	Avoided cost of routine reading (including reductions in costs of PDEs and route management)	290	298	8	0	
6	Avoided cost of special reads	139	171	8	25	Cost per read revised upwards
7	Avoided cost of time switch replacement and O&M	93	99	5	0	

43 Rounded to nearest million dollars.

44 The methodology and benefit-specific inputs used in the 2009 Benefits Report have been accepted unless otherwise noted.

45 Shaded cells indicate those benefits whose methodologies and/or benefit-specific inputs have been revised in the OGW review.

46 See Section 4.2 for a discussion of these assumptions.

47 These are discussed on a benefit-by-benefit basis in Section 4.3.

Benefit No	Benefit	Value (2008$ M[43]) in		Amount (2008$ M[38]) due to change in		Most significant benefit-specific changes[44]
		2009 Benefits Report (low)	OGW Review[45] (low)	General economic and market assumptions[46]	Benefit-specific inputs[47]	
8	Avoided additional cost of energy from time switch clock errors	48	41	3	-11	Energy cost savings revised downwards Augmentation savings had been overlooked
9	Avoided cost of manual disconnections and reconnections (and avoided revenue loss)	140	364	5	219	Cost per disconnect/reconnect revised upwards Average hours of unserved energy revised upwards A more representative VCR value was used Incidence of the service had been underestimated for one DB
10	Avoided cost of setting demand limits for customers to promote fair sharing and defer augmentation capex	5	5	0	0	
11	Ability to set emergency demand limits to share limited supply at times of network stress or supply shortage	422	0	6	-428	Input used for VCR had no empirical base Historical base used is highly variable Benefit of a highly probabilistic nature; more appropriately characterised as an insurance value
12	Avoided cost of supply capacity circuit breaker	4	4	0	0	
13	Avoided cost of replacing service fuses that fail from overload	5	5	0	0	

Benefit No	Benefit	Value (2008$ M[43]) in		Amount (2008$ M[38]) due to change in		Most significant benefit-specific changes[44]
		2009 Benefits Report (low)	OGW Review[45] (low)	General economic and market assumptions[46]	Benefit-specific inputs[47]	
14	Avoided cost of investigation of customer complaints about voltage QoS, including equipment cost and cost of reporting to regulator	38	39	1	0	
15	Reduced cost for post storm supply restoration - avoid delays in detecting and correcting nested outages	9	9	0	0	Accepted the methodology and inputs in the 2009 Benefits Report but also note that the benefit value is significantly underestimated due to the lack of data with which to accurately estimate the avoided unserved energy and the reduced need for DB fault restoration labour
16	Reduction in calls to faults and emergencies lines	14	14	0	0	
17	Avoided cost of investigation of customer complaints of loss of supply which turn out to be not a loss of supply	14	15	1	0	
18	Avoided cost of end of line monitoring	4	4	0	0	
19	Reduction in unserved energy (with quicker detection of outages and quicker restoration times)	126	375	2	247	Base SAIDI figures were revised Impact on SAIDI revised upwards Benefit had been conceptualised as affecting only small-volume customers, but will actually affect all customers
20	Avoided cost of communications to feeder automation equipment	3	3	0	0	
21	Avoided cost of proportion of HV/LV transformer fuse operations on overload	5	5	0	0	

Benefit No	Benefit	Value (2008$ M[43]) in		Amount (2008$ M[38]) due to change in		Most significant benefit-specific changes[44]
		2009 Benefits Report (low)	OGW Review[45] (low)	General economic and market assumptions[46]	Benefit-specific inputs[47]	
22	Avoided cost of a proportion of transformer failures on overload	20	28	0	8	Reduction in USE due to this benefit that had not been accounted for was incorporated
23	Reduction in calls related to estimated bills and high bill enquiries	5	5	0	0	
24	Reduction in energy trading costs through improved wholesale forecasting accuracy	8	8	0	0	
25	Reduction in the administration cost of bad debt incurred on non-payment on move outs	2	2	0	0	
26	Customer benefit of being able to switch retailer more quickly and more certainly. Note: this is not the bill saving	7	8	1	0	
27	Reduction in MDA costs - putting I&C customers on DB AMI networks	25	26	1	0	
28	Ability for customers to move to monthly billing on the basis of electronic bills, reducing, admin costs, collection costs etc	0	0	0	0	
29	Avoided network and generation augmentation from peak demand reduction from three-rate TOU network tariff introduction and resultant three-rate retail tariff	89	44	0	-45	Take-up of the TOU tariff revised downwards Cost of avoided infrastructure had been understated
30	Avoided network and generation augmentation from peak demand reduction from CPP tariff implementation	73	133	0	60	Cost of avoided generation and network infrastructure revised upwards Benefit will accrue as rollout proceeds, not just when rollout is complete

Benefit No	Benefit	Value (2008$ M[43]) in		Amount (2008$ M[38]) due to change in		Most significant benefit-specific changes[44]
		2009 Benefits Report (low)	OGW Review[45] (low)	General economic and market assumptions[46]	Benefit-specific inputs[47]	
31	Energy conservation from three-rate TOU tariff	123	49	0	-74	Take-up of the TOU tariff revised downwards Cost of avoided energy revised upwards
32	Energy conservation from CPP tariff implementation	10	10	0	0	
33	Additional demand response from IHDs on CPP	4	4	0	0	
34	Additional demand response from direct load control of air conditioners	85	113	1	26	Cost of avoided generation and network infrastructure revised upwards Benefit will accrue as rollout proceeds, not just when rollout is complete
35	Energy conservation from IHDs	49	50	1	0	
35a	Energy conservation from general information programs		44	0	44	Benefit had not been addressed
36	Peak demand reduction through deferral of refrigerator auto defrost cycle out of peak period	28	28	1	0	
37	Avoided cost of other communications to manage customers' loads for renewable generation tracking, electric vehicle charging and local generation management	34	35	1	0	
38	Revenue from reading smart water meters for water utilities	60	0	0	-60	AMI enables this benefit, but it should be taken up in the cost-benefit case for water meters Payments from water companies to DBs are a transfer, not a benefit
Total		2,481	2,577	84	12	

4.4.2. Categorisation of benefits by likelihood of realisation

The benefits identified and discussed in the 2009 Benefits Report can be categorised by the conditions that need to pertain in order for their value to be realised. Based on our review of the benefits as described in the 2009 Benefits Report we have identified the following four categories, listed in increasing stringency of the conditions they require for benefit realisation:

1. Benefits resulting from operation of AMI technology as specified for the Victorian AMI Rollout;
2. Benefits that result directly from the operation of additional AMI functionality that will require additional expenditure;
3. Benefits that require legislative, regulatory or market rules changes on the part of Government, the AER, or the AEMC; and
4. Benefits that require discretionary actions on the part of electricity retailers and/or customers.[48]

Because the conditions that must be met for the associated AMI benefits to be realised are more stringent as we progress down the list of categories, we believe the benefits associated with the lower-numbered categories are more likely to be realised. Further detail on the benefit categories is presented below.

Benefits that result directly from the operation of the AMI technology as specified for the Victorian Rollout

An example of benefits that result directly from the operation of the AMI technology as specified for the Victorian AMI Rollout is the avoided cost of routine meter reading (Benefit 5). The AMI infrastructure enables this benefit almost automatically. While some of the benefits included in this category will require changes in DB operating practices, we have assumed that these changes will be made because of either (a) the benefits that the distributor can obtain from these aspects of the AMI functionality, and/or (b) the potential for them to be required within the regulatory determination that sets cost recovery of AMI expenditure.[49]

A total of 11[50] of the benefits with an aggregate present value of $1,531 million (as re-estimated in this review) fall into this category. They are:

- Benefit 2, Avoided costs of meter replacement programs
- Benefit 3, Reduced testing of meters
- Benefit 5, Avoided cost of routine reading (including reductions in costs of PDEs and route management)
- Benefit 6, Avoided cost of special reads

---

48 A number of the benefits require actions that apply to more than one of the categories. For example, a benefit might require (or at least profit from) Government action as well as voluntary actions on the part of retailers or consumers. In such cases, the benefit was put in the category that included the most stringent condition applicable to that benefit. For example if a benefit required both Government action and voluntary action by an electricity retailer, it was placed in the last category.

49 We differentiate these benefits from those in the third category by the fact that any regulatory action imposed in this category would be routine part of a regulatory function associated with that expenditure.

50 Excludes Benefit 38, *Revenue from reading smart water meters for water utilities*, which was determined to be a transfer and whose benefit value was therefore zeroed out.

- Benefit 7, Avoided cost of time switch replacement and O&M
- Benefit 8, Avoided additional cost of energy from time switch clock errors
- Benefit 9, Avoided cost of manual disconnections and reconnections (and avoided revenue loss)
- Benefit 12, Avoided cost of supply capacity circuit breaker
- Benefit 13, Avoided cost of replacing service fuses that fail from overload
- Benefit 17, Avoided cost of investigation of customer complaints of loss of supply which turn out to be not a loss of supply
- Benefit 37, Avoided cost of other communications to manage customers' loads for renewable generation tracking, electric vehicle charging and local generation management.

Benefits that result directly from the operation of additional AMI functionality that will require additional expenditure

Benefits that result directly from the operation of additional AMI functionality that will require additional expenditure will accrue in much the same way as those discussed in the first category immediately above, but will require expenditure beyond that included in the specification mandated by the Victorian Government and approved by the AER. An example of this group of benefits is Benefit 19, *Reduction in unserved energy (with quicker detection of outages and quicker restoration times)*, which will require integration of the AMI system and DBs' outage management systems, the cost of which was estimated in the 2009 Benefits Report at somewhere between $2.4 and $3.6 million.

A total of 15 of the benefits with an aggregate present value of $505 million (as re-estimated in this review) fall into this category. They are:

- Benefit 4, Reduced cost of network loading studies for network planning
- Benefit 14, Avoided cost of investigation of customer complaints about voltage QoS, including equipment cost and cost of reporting to regulator
- Benefit 15, Reduced cost for post storm supply restoration – avoid delays in detecting and correcting nested outages
- Benefit 16, Reduction in calls to faults and emergencies lines
- Benefit 18, Avoided cost of end of line monitoring
- Benefit 19, Reduction in unserved energy (with quicker detection of outages and quicker restoration times)
- Benefit 20, Avoided cost of communications to feeder automation equipment
- Benefit 21, Avoided cost of proportion of HV/LV transformer fuse operations on overload
- Benefit 22, Avoided cost of proportion of transformer failures on overload
- Benefit 23, Reduction in calls related to estimated bills and high bill enquiries
- Benefit 24, Reduction in energy trading costs through improved wholesale forecasting accuracy
- Benefit 25, Reduction in the administration cost of bad debt incurred on non-payment on move outs
- Benefit 26, Customer benefit of being able to switch retailer more quickly and more certainly

- Benefit 28, Ability for customers to move to monthly billing on the basis of electronic bills, reducing administrative and collection costs
- Benefit 38, Revenue from reading smart water meters for water utilities.[51]

Benefits that require legislative, regulatory or market rules changes on the part of Government, the AER, or the AEMC

Benefit 27, *Reduction in MDA costs by putting I&C customers on DB AMI networks* is an example of benefits that will require legislative, regulatory or market rules changes on the part of Government, the AER, or the AEMC. Realisation of this benefit will require a change in the National Electricity Rules that explicitly allows the meters of customers with annual electricity consumption above 160 MWh to be read via AMI.

A total of 4 benefits with an aggregate present value of $66 million (as re-estimated in this review) fall into this category.[52] They are:

- Benefit 1, Avoided costs of installing import / export metering
- Benefit 10, Avoided cost of setting demand limits for customers to promote fair sharing and defer augmentation capex
- Benefit 11, Ability to set emergency demand limits to share limited supply at times of network stress or supply shortage
- Benefit 27, Reduction in MDA costs – putting I&C customers on DB AMI networks

Benefits that require electricity retailers and/or electricity consumers to undertake voluntary actions

A number of the benefits require voluntary actions on the part of either or both electricity retailers or consumers in order for their benefits to accrue. The prime examples of these types of benefits are those that involve the take-up of TOU or CPP tariffs. The availability of these tariffs at the retail level is entirely at the discretion of the retailer. While the Victorian Government could mandate the offering of these tariffs by all retailers, it is unlikely that it would require that such tariffs be the only type allowed to be offered (and it is arguable whether such a requirement would withstand legal challenge if one were to be made). Furthermore, take-up of such a tariff would then also depend on the decisions of individual consumers.

A total of 9 benefits with an aggregate present value of $475 million (as re-estimated in this review) fall into this category. They are:

- Benefit 29, Avoided network and generation augmentation from peak demand reduction from three-rate TOU network tariff introduction and resultant three-rate retail tariff
- Benefit 30, Avoided network and generation augmentation from peak demand reduction from CPP tariff implementation
- Benefit 31, Energy conservation from three-rate TOU tariff
- Benefit 32, Energy conservation from CPP tariff implementation
- Benefit 33, Additional demand response from IHDs on CPP

---

51 Note that the revised value of this benefit is zero.

52 Note that the value of Benefit 11 has been taken as zero for the purpose of the present calculations. It remains in the list of benefits because we believe strongly that its benefit is non-zero, but the information presently available to calculate its value is not sufficiently robust.

- Benefit 34, Additional demand response from direct load control of air conditioners
- Benefit 35, Energy conservation from IHDs
- Benefit 35a, Energy conservation from general information programs
- Benefit 36, Peak demand reduction through deferral of refrigerator auto defrost cycle out of peak period.

4.5. Summary of high case benefit assessment

A limited review was undertaken of the high case benefits estimated in the 2009 Benefits Report. Our review has been limited to those benefits whose 'benefit specific inputs' were changed when we reviewed the low case benefits. This limited review was felt to be sufficient and consistent with the overall objective of this 2010 Benefits Review, which is to establish whether the policy decision to mandate the AMI Rollout as part of the overall AMI Program was cost-justified. It also ensures that the values of our high case benefits are consistent and comparable with our low case benefits. Table 8 below presents the results of our review of high case benefits.

Table 8: Comparison of benefit values from the 2009 Benefits Report (high case) and the high benefit values from this review

Benefit No.	Benefit description	Value (2008$ M[53]) in		Most significant benefit-specific changes[54]
		2009 Benefits Report (high)	OGW Review (high)	
6	Avoided cost of special reads	211	171	Cost per read revised upwards
8	Avoided additional cost of energy from time switch clock errors	97	82	Energy cost savings revised downwards Augmentation savings had been overlooked
9	Avoided cost of manual disconnections and reconnections (and avoided revenue loss)	385	646	Cost per disconnect/reconnect revised upwards Average hours of unserved energy revised upwards VCR value amended to more representative value Incidence of the service revised upwards for one DB
11	Ability to set emergency demand limits to share limited supply at times of network stress or supply shortage	628	0	Input used for VCR had no empirical base Historical base used is highly variable Benefit of a highly probabilistic nature; more appropriately characterised as an insurance value

53 Rounded to nearest million dollars.

54 The methodology and benefit-specific inputs used in the 2009 Benefits Report have been accepted unless otherwise noted.

Benefit No.	Benefit description	Value (2008$ M[53]) in		Most significant benefit-specific changes[54]
		2009 Benefits Report (high)	OGW Review (high)	
19	Reduction in unserved energy (with quicker detection of outages and quicker restoration times)	345	600	Base SAIDI figures were revised Impact on SAIDI revised upwards Benefit had been conceptualised as affecting only small-volume customers, but will actually affect all customers
29	Avoided network and generation augmentation from peak demand reduction from three-rate TOU network tariff introduction and resultant three-rate retail tariff	521	148	Take-up of the TOU tariff revised downwards from 95% to 40% Cost of avoided infrastructure revised upwards
30	Avoided network and generation augmentation from peak demand reduction from CPP tariff implementation	465	370	Cost of avoided generation and network infrastructure revised upwards Benefit will accrue as rollout proceeds, not just when rollout is complete
31	Energy conservation from three-rate TOU tariff	796	174	Take-up of the TOU tariff revised downwards from 95% to 40% Cost of avoided energy had been understated
34	Additional demand response from direct load control of air conditioners	581	417	Cost of avoided generation and network infrastructure revised upwards Benefit will accrue as rollout proceeds, not just when rollout is complete
35a	Energy conservation from general information programs	0	38	Benefit had not been addressed
38	Revenue from reading smart water meters for water utilities	119	0	AMI enables this benefit, but it should be taken up in the cost-benefit case for water meters Payments from water companies to DBs is a transfer, not a benefit
Subtotal		*4,148*	*2,645*	
All others	All other benefits	2,359	2,359	
Total		6,507	5,004	

Appendix A: Benchmarking and related studies reviewed

American Electric Power (AEP), Ohio, *AEP Ohio Receives Federal Funding to Initiate gridSMART Project*, News Release, 24 November 2009. Available at: https://www.aepohio.com/info/news/viewRelease.aspx?releaseID=778.

BC Hydro, *Smart Metering and Smart Grid Programs FAQs*. Available at: http://www.bchydro.com/planning_regulatory/projects/smart_metering_infrastructure_program/faqs.html

Department of Energy and Climate Change (UK), *Towards a smarter future: Government response to the consultation on electricity and gas smart metering*, December 2009. Available at: http://www.decc.gov.uk/en/content/cms/consultations/smart_metering/smart_metering.aspx.

Department of Energy and Climate Change (UK), *Impact assessment of a GB-wide smart meter roll out for the domestic sector*, December 2009. Available at: http://www.decc.gov.uk/en/content/cms/consultations/smart_metering/smart_metering.aspx.

Department of Energy and Climate Change (UK), *Impact Assessment of smart / advanced meters roll out to small and medium businesses*, December 2009. Available at: http://www.decc.gov.uk/en/content/cms/consultations/smart_metering/smart_metering.aspx.

Du Bois, Dennis, *Time of Use Electricity Billing: How Puget Sound Energy Reduced Peak Power Demands (Case Study)*, Energy Priorities, 14 February 2006. Available at: http://energypriorities.com/entries/2006/02/pse_tou_amr_case.php.

Edison International*, Edison Announces Advanced New Meter Will Reach Customers Sooner Than Expected*, News Release, 21 August 2006. Available at: http://www.edison.com/pressroom/pr.asp?id=6350.

Faruqui, Ahmad; and Sanem Sergici, *Household Response to Dynamic Pricing of Electricity–A Survey of the Empirical Evidence*, The Brattle Group, February 2010. Available at: http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1134132.

Faruqui, Ahmad; and Dan Harris, *Lessons from Demand Response - Trials and Potential Savings for the EU*, The Brattle Group, 12 October 2009. Available at: http://www.brattle.com/_documents/UploadLibrary/Upload806.pdf.

Faruqui, Ahmad; Sanem Sergici; and Ahmed Sharif, *The Impact of Informational Feedback on Energy Consumption–A Survey of the Experimental Evidence*, The Brattle Group, 20 May 2009. Available at: http://www.smartgridnews.com/artman/uploads/1/The_Impact_of_Informational_Feedback__05-20-09_.pdf

Faruqui, Ahmad; and Sanem Sergici, *BGE's Smart Energy Pricing Pilot Summer 2008 Impact Evaluation*, The Brattle Group, prepared for Baltimore Gas & Electric Company, 28 April 2009. Available at: http://www.brattle.com/_documents/uploadlibrary/upload768.pdf.

Faruqui, Ahmad; Sanem Sergici; Cheryl Hindes; and Neel Gulhar, *California and Maryland - Are They Poles Apart?,* The Brattle Group and Baltimore Gas and Electric Company, 12 March, 2009. Available at: http://www.brattle.com/Publications/ReportsPresentations.asp?PublicationID=1048.

Hydro Ottawa, *Time-of-use Rates FAQs*. Available at: http://www.hydroottawa.com/smartmeter/index.cfm?lang=e&template_id=359.

Oncor Electric Delivery (Texas), *Components of AMS Surcharge*, undated. Available at: http://www.oncor.com/tech_reliable/pdf/Oncor-AMS-Surcharge-Analysis.pdf

Ontario Energy Board, *Smart Meter Implementation Plan, Report of the Board to the Minister, Appendices*, Appendix C, Costs (and benefits), 26 January 2006. Available at: http://www.oeb.gov.on.ca/documents/communications/pressreleases/2005/press_release_sm_appendices_260105.pdf.

Ontario Energy Board, *Smart Metering Initiative*, webpage. Available at: http://www.oeb.gov.on.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Smart+Metering+Initiative+(SMI)/Smart+Metering+Initiative+History.

PECO, Philadelphia. *Investments in Reliability | Smart Meters*, webpage. Available at: http://www.exeloncorp.com/energy/delivery/peco.aspx

Pennsylvania Power & Light, *Act 129 Smart Meter Milestone Plan*. Available at: http://www.pplelectric.com/Business+Partners/Tools+and+Reference+Center/Act+129+Smart+Meter+Plan/?WBCMODE=PresentationUnpublished.

Pollom, Brian (InteGride Inc), *Puget Sound Energy AMR & Demand Response Case Study*, Oregon Public Utility Commission Advanced Metering Workshop, 6 January, 2005. Available at: http://www.oregon.gov/PUC/electric_gas/010605/pollom.pdf.

Portland General Electric, *OPUC Approves PGE Investment in Smart Meter Technology*, News Release, 6 May 2008. Available at: http://investors.portlandgeneral.com/releasedetail.cfm?ReleaseID=308661.

Portland General Electric, *Smart Meters FAQs*. Available at: http://www.portlandgeneral.com/smartmeter/faq.aspx.

Public Utilities Commission of Texas, *A Report on Advanced Electric Metering as Required by House Bill 2129*, Report to the 81st Legislature, September 2008. Available at: http://www.centerpointenergy.com/staticfiles/CNP/Common/SiteAssets/doc/Commission_Report_on_Advanced_Metering_2008.pdf.

Rochester Gas & Electric Corporation (RG&E) and New York State Electricity & Gas (NYSEG), Advanced Metering Infrastructure Update, Filing to State of New York, Public Service Commission, May 2007. Available at: http://www.dps.state.ny.us/AMI.htm.

Schoenwetter, Sara (Attorney for Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc), Plan for development and deployment of advanced electric and gas metering infrastructure by Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc., Filing to State of New York, Public Service Commission, March 2007. Available at: http://www.dps.state.ny.us/AMI.htm.

Thompson, Vicki L (Attorney for San Diego Gas & Electric), *Advanced metering infrastructure (AMI) business case supplemental filing*, Filing to the Public Utilities Commission of the State of California, 12 January 2005. Available at: http://sites.energetics.com/madri/toolbox/pdfs/business_cases/sdge_supplemental.pdf