



# **Cost-benefit analysis of proposed rule changes for Part D**

**Report to the Electricity Commission**

**20 April 2010**



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## Executive summary

Part D of the Electricity Governance Rules 2003 (the rules) provides the regulatory framework for metering in the New Zealand electricity industry. The Electricity Commission (the Commission) has completed a fundamental review of Part D to identify and address the problems and deficiencies of the existing rules and to enable the adoption of new metering technology, such as smart meters.

In discussion with industry, the Commission has explored the options for improving the current regulatory requirements. Following formal consultation with industry, the Commission has now determined the preferred option in each of four main areas and the proposed rule changes required to give them effect. These four preferred options are:

- move responsibility for compliance of all equipment and components at each metering installation to the metering participant
- require certification of load control devices used for settlement purposes
- establish a central database of metering information by enhancing the Commission's electricity registry and
- introduce standards for certification and auditing of metering participants and enhance standards for certification and auditing of approved test houses (ATHs), metering participant and ATH responsibilities and metering installation requirements.

The Commission has asked NZIER to provide an analysis of the costs and benefits of the proposed rule changes for these preferred options.

This cost-benefit analysis (CBA) finds that, although initial implementation costs would be considerable, once implemented, the proposed rule changes, in total, would deliver over five times as much in ongoing benefits as they would incur in ongoing costs. Following implementation, costing \$34.7 million over six years, the ongoing net benefits are estimated to be \$19.3 million per year.

Over the 10 year period 2009/10 to 2018/19, we estimate the proposed rule changes, in total, to deliver present value net benefits of \$52.0 million (total benefits of \$104.3 million less total costs of \$52.3 million). For each dollar of cost, they would return \$1.99 in benefits. They would break even by mid 2014.

Of the preferred options, requiring certification of load control devices used for settlement purposes accounts for almost half the present value total costs of the proposed rule changes over the next 10 years, but also almost a third of the total benefits. Introducing and enhancing standards for certification, auditing, responsibilities and requirements incurs a third of the total costs and delivers over two fifths of the total benefits. Moving responsibility for metering installation compliance to metering participants and establishing a central database by enhancing the electricity registry are the least costly of the preferred options, but also

provide the smallest benefits. Nevertheless, each of the preferred options individually would deliver more in benefits than it would cost. Furthermore, NZIER's previous CBAs of the shortlisted options in each of these four areas also showed the preferred options to deliver greater net benefits than the alternative options assessed in each of these four areas.

This CBA suggests that metering participants would bear three quarters of the present value total costs of the proposed rule changes over the next 10 years. Three fifths of the total benefits would be market wide, in which metering participants would share. Of the market wide benefits, almost half are due to the deferral of investment expenditure enabled by greater compliance of load control devices resulting in increased reliability, availability and use of load control. The remaining half derive from increased efficiency in the market for electricity due to greater compliance of metering installations and more accurate metering information resulting in more accurate allocation of costs between market participants.

Despite uncertainty about the costs and benefits, sensitivity analysis shows that even if all of the implementation and ongoing costs of all of the proposed rule changes were 25% higher and all of the benefits 25% lower than modelled, the proposed rule changes would still deliver present value net benefits of \$12.9 million over the next 10 years. This indicates that market participants can be confident that the proposed rule changes would provide significant net benefits over the status quo of retaining the existing regulatory requirements under the existing rules.

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# 1. Purpose

Part D of the Electricity Governance Rules 2003 (the rules) provides the regulatory framework for metering in the New Zealand electricity industry. The Electricity Commission (the Commission) has completed a fundamental review of Part D to identify and address the problems and deficiencies of the existing rules and to enable the adoption of new metering technology, such as smart meters.

Before making a recommendation to the Minister for changes or additions to the rules, under Section 172F(1) of the Electricity Act 1993, the Commission must:

- identify all reasonably practicable options for achieving the objective of the rules
- assess those options by considering:
  - the benefits and costs of each option
  - the extent to which the objective would be promoted or achieved by each option and
  - any other matter that the Commission considers relevant.

In discussion with industry, the Commission identified and assessed the reasonably practicable options for improving the current regulatory requirements in four main areas<sup>1</sup>:

- responsibility for compliance of metering installations
- certification of load control devices
- central database of metering information and
- standards for certification and auditing of metering participants and approved test houses (ATHs), metering participant and ATH responsibilities and metering installation requirements.

Following formal consultation with industry on the options, the Commission has now determined the preferred options and the proposed rule changes.

NZIER previously assisted the Commission's assessment by providing analyses of the costs and benefits of the shortlisted options in each of the four areas above. The Commission has now asked NZIER to provide an analysis of the costs and benefits of the proposed rule changes for the preferred options. This report outlines the method and results of this cost-benefit analysis (CBA).

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<sup>1</sup> There are also many other rule changes proposed, which would contribute to the effectiveness of the rule changes proposed in these four main areas.

## 2. Method

### 2.1 Cost-benefit analysis

CBA provides a formal, structured method for systematically assessing proposals in terms of their outcomes relative to their use of resources. In the analysis of government policy, CBA is normally undertaken from a national economy perspective, weighing up the relative costs and benefits to New Zealand as a whole.

The CBA process comprises 10 steps:

1. define the problem
2. select the options for assessment
3. specify the baseline scenario
4. identify the impacts of the options – positive (benefits) and negative (costs)
5. where possible, quantify the impacts
6. where possible, value the impacts
7. adjust for differences in the timing of the impacts
8. calculate decision criteria
9. analyse the sensitivity of the results and
10. document the CBA

### 2.2 Preferred options

The preferred options in each of the four main areas assessed, to which the proposed rule changes apply, are:

- move responsibility for compliance of all equipment and components at each metering installation to the metering participant
- require certification of load control devices used for settlement purposes
- establish a central database of metering information by enhancing the Commission's electricity registry and
- introduce standards for certification and auditing of metering participants and enhance standards for certification and auditing of approved test houses (ATHs), metering participant and ATH responsibilities and metering installation requirements.

### 2.3 Baseline scenario

A critical step in any CBA is defining the baseline scenario – the default or prevailing situation or conditions that would occur in the absence of the options under consideration. It is relative to this baseline that the options' costs and benefits are measured.

For the purpose of assessing the proposed rule changes for the preferred options above, we define the baseline scenario as the "status quo" – not implementing any of these options, but instead continuing with the existing regulatory requirements under the existing rules. We assess how much the preferred options would cost in total to

implement and operate under and how much they would deliver in total benefits relative to this status quo.

## 2.4 Unit costs and benefits

The Commission used an industry reference group (IRG) to explore the reasonably practicable options in each of the four main areas and their effects on market participants. Members of the IRG were asked to indicate the likely costs and benefits they thought each of the options would have, on both their own business and the industry. As part of the subsequent formal consultation process, industry was also invited to comment on NZIER's previous CBAs of the shortlisted options.

Table 1 to Table 4 below show the average cost and benefit per participant modelled for each of the preferred options<sup>2</sup>. Costs are divided into initial development and implementation costs and ongoing annual costs of operating under the preferred options proposed. The costs and benefits used in this CBA have been amended for comments provided by industry on the previous CBAs of the shortlisted options. In some cases, the opinions of the IRG ranged widely. For Table 1, for example, the majority of members of the IRG considered the additional contracting costs likely to be minor or nil, given existing contracts, but a minority considered that they could be very substantial. We have sought to represent the averages. Given the uncertainty of these costs and benefits, we test the sensitivity of the results across a range of values for each type of cost and benefit (see Section 3.3 below).

Note that the costs and benefits shown are relative to the status quo of existing requirements. In other words, they show the increase or decrease in costs and benefits from existing levels. In a number of cases, the IRG considered that the proposed requirements could be accommodated within existing systems and processes without adding significantly to costs (or with adding to some costs as much as they reduced other costs, so having no net impact) or would provide some benefits in the form of savings in compliance costs where requirements would be eased.

Note also that the ongoing costs and benefits shown are expressed in annual terms per participant, other than where indicated. For Table 4 in particular this involves multiplying cost per visit, application, notification, incident, etc. by the average number of visits, applications, notifications, incidents, etc. per participant per year. It also involves adjusting the cost of inspection or audit by the frequency of inspection or audit to give the average cost (or cost saving) per participant per year.

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<sup>2</sup> A further possible benefit of the proposed rule changes is that the associated infrastructure and standardised formats would reduce the costs to industry of obtaining and transferring data between owners of advanced metering infrastructure and market participants and support use of electric vehicles and distributed generation.

**Table 1 Unit costs and benefits – move responsibility for metering installation compliance to metering participants**

Relative to status quo – current compliance responsibility

	Frequency	Cost or benefit per participant (\$)					Market wide cost or benefit (\$)
		Distributor	Trader	Metering participant	MCO	Commission	
<b>Costs</b>							
Develop and agree detailed requirements	One off total	2,000	10,000	10,000	1,000	50,000	
Negotiate contracts	One off total		25,000	175,000	2,000		
Co-ordinate and deal with MCOs	Ongoing annual			50,000			
Comply with metering participants' requirements	Ongoing annual				2,000		
Compliance and audit processes	Ongoing annual			25,000			
Monitor and enforce compliance	Ongoing annual					50,000	
<b>Benefits</b>							
Time saving from single point of contact for compliance issues	Ongoing annual	10,000					
Time saving in dealing with mixed ownership metering installations	Ongoing annual		25,000	25,000	2,000		
Reduced costs of compliance and audit processes	Ongoing annual		25,000				
Efficiency benefits resulting from greater compliance of metering installations enabling more accurate billing and reconciliation	Ongoing annual						1,750,000

Source: Industry Reference Group, industry submissions, Electricity Commission, NZIER

**Table 2 Unit costs and benefits – require certification of load control devices used for settlement purposes<sup>1</sup>**

Relative to status quo – no certification requirements

	Frequency	Cost or benefit per participant (\$)				Market wide cost or benefit (\$)
		Distributor	Trader	Metering participant	Commission	
<b>Costs</b>						
Develop and agree detailed requirements	One off total	4,000	20,000	20,000	75,000	
Upgrade existing load control equipment	One off total <sup>2</sup>			2,500,000		
Standardise systems and standards for load control	One off total			45,000		
Upgrade load control field devices	One off total <sup>2</sup>			90,000		
Amend systems and processes to gather and store required data	One off total			45,000		
Testing, certification, auditing and record keeping	Ongoing annual			45,000		
Monitor and enforce compliance	Ongoing annual				45,000	
<b>Benefits</b>						
Fewer failures in facilitating existing load control, enabling lower peak loads and tariffs and therefore deferral of investment expenditure	Ongoing annual <sup>3</sup>					1,760,000 <sup>4</sup>
Time saving in checking that relays that switch tariffs are working correctly	Ongoing annual <sup>3</sup>		10,000			
Time saving in managing tariff changes for customers	Ongoing annual <sup>3</sup>		10,000			
Time saving from fewer customer complaints about incorrect tariffs due to fewer failures in facilitating load control	Ongoing annual <sup>3</sup>		25,000			
Increased availability and use of load control, enabling further reductions in peak loads and tariffs and therefore further deferral of investment expenditure	Ongoing annual <sup>3</sup>					6,600,000 <sup>5</sup>

**Notes:**

<sup>1</sup> Assuming that 90% of all load control devices are used for settlement purposes, given very few situations where there is no commercial reason for installing a load control device.

<sup>2</sup> Assuming that upgrades are spread over five years, as sites become recertified.

<sup>3</sup> Phased in over five years, following upgrades to load control equipment and field devices.

<sup>4</sup> Assuming, conservatively, that around 5% of load control devices are currently inoperable and certification requirements would reduce this to 1%, for existing controllable load of 880 MW, at an average value of around \$50,000/MW, based on Value/Price Working Panel (2007) *Load Management Value and Pricing Report*, Retail Market Advisory Group meeting, 7 August 2007, [www.electricitycommission.govt.nz/pdfs/advisorygroups/rmag/7Aug07/7a-Appendix2.pdf](http://www.electricitycommission.govt.nz/pdfs/advisorygroups/rmag/7Aug07/7a-Appendix2.pdf)

<sup>5</sup> Assuming, conservatively, that greater reliability of load control devices would stimulate a 15% increase in controllable load, where there are commercial incentives to use it, from the existing level of 880 MW, at an average value of around \$50,000/MW.

Source: Industry Reference Group, industry submissions, Electricity Commission, NZIER

**Table 3 Unit costs and benefits – establish central database by enhancing the electricity registry**

Relative to status quo – current access to metering information

	Frequency	Cost or benefit per participant (\$)				Market wide cost or benefit (\$)
		Distributor	Trader	Metering participant	Commission	
<b>Costs</b>						
Develop and agree detailed requirements	One off total	2,100	10,500	10,500	52,500	
Upgrade Commission's electricity registry	One off total				450,000	
Implementation and integration	One off total		300,000	300,000		
Electricity registry operation and licensing	Ongoing annual				50,000	
Data maintenance	Ongoing annual			57,000		
Compliance and audit	Ongoing annual		10,000	10,000		
Monitoring of metering participant compliance	Ongoing annual				50,000	
<b>Benefits</b>						
Time saving in investigating sites to obtain accurate metering information	Ongoing annual		10,000	10,000		
Time saving from fewer customer complaints	Ongoing annual		25,000			
Lower costs of compliance and audit for retailers	Ongoing annual		25,000			
Efficiency benefits from improved accuracy at time of switch and post switch, enabling more accurate quotation, billing and reconciliation	Ongoing annual					3,045,000

Source: Industry Reference Group, industry submissions, Electricity Commission, NZIER

**Table 4 Unit costs and benefits – introduce and enhance standards for certification, auditing, responsibilities and requirements**

Relative to status quo – existing standards

		Cost or benefit per participant (\$)							Market wide	
		Trader		Metering participant		ATH		Commission	cost or benefit (\$)	
		One off total	Ongoing annual	One off total	Ongoing annual	One off total	Ongoing annual	One off total	Ongoing annual	Ongoing annual
<b>Costs</b>										
Develop and agree detailed requirements		10,000		10,000		10,000		50,000		
Greater scrutiny of metering participants	A flexible auditing system – maximum frequency every two months, minimum frequency every three years				5,000				2,000	
	AND Require ISO9001			30,000 to obtain or 5,000 to modify existing certification <sup>2</sup>	4,500 <sup>2</sup>					
	AND A sample of inspections to be conducted in accordance with the principles of AS1284, using Commission approved auditor or Commission approved auditor may accept an internal audit process; inspections of a standard that could be used as part of the metering participant's inspection programme			4,000	45 for category 1 and 15 for categories 2 to 6					
Changes to ATH audits	A flexible auditing system – maximum frequency every two months, minimum frequency every three years (currently two-yearly for class B, three-yearly for class A)						3,300 for class A and 825 for class B			
	AND Auditors to check ATH workload and staffing levels and position descriptions						133	400		
Nominated standards process	A party promoting a change in standards would need to provide evidence of suitability (equivalent or superior, safety requirements, radio spectrum requirements)				10,000 <sup>4</sup>					
	AND Commission to consider a change in standards promoted; would require engaging suitable experts								10,000	
	AND Where a change is considered appropriate, a rule change would be required								7,500 <sup>14</sup>	

Dealing with underburdening	Where burdens are lower than the nominated standards test points, the ATH will seek confirmation of accuracies from measuring transformer manufacturers						1,000			
AND	Burden resistors to be used unless an alternative is mathematically beneficial (only applies to grid-metering)				3,000 <sup>5</sup>					
Opaque test blocks can mask problems	In line with existing good practice, all newly installed or replaced test blocks must have transparent covers			25 <sup>3</sup>						
New work in progress certification process	ATHs to establish process for compiling and lodging work in progress					400				
AND	Market administrator to handle work in progress							3,000	5,000	
Processes to deal with insufficient load for testing	ATH must perform an additional check of the metering installation wiring and record the results									
AND	On the certification issued, the ATH must record the absence of a normal series of tests					400				
AND	Metering participant must keep records of such metering installations									
AND	Metering participant must monitor monthly for sufficient load on such metering installations									
AND	Where sufficient load becomes available, retesting must occur									
AND	Where retesting demonstrates inaccuracy, the metering installation must be recertified									
Changes made to certification sticker procedures	Changes to sticker information, which would require a change in sticker design					1,500				
Timekeeping requirement for hybrid metering introduced	Introduced and set at +/-90 seconds									
Change in responsibility for statistical sampling	Metering participant, instead of ATH, to be responsible for existing Rule 5.3 of Code of Practice Schedule D3									
Change to commissioning tests	For half-hour metering of category one, an "output to host" check would be either a half-hour load test (as per existing requirements) or an instantaneous register comparison									
Checks when trader changes	Gaining trader must verify the certification, check the meter multipliers and review data compensation arrangements									

Changes to use of metering transformers	When to be used as part of a "selected component installation", if it has been more than two years since original sample testing, retesting must be conducted					50 <sup>9</sup>				
Changes to inspection requirements	Where non-half hour metering is interrogated remotely, the reconciliation participant must download event logs and perform validation									
	AND Where non-half hour metering is interrogated manually, the reconciliation participant must perform a non-invasive check; minimum checks would be – ensuring seals are present, checking for phase failure where the metering supports it, and obvious signs of tampering		1.20 <sup>1</sup>							
	AND Earlier inspection requirement from within first 10 years to within first five years for category 2 installations (but only one inspection during lifetime of certification)					47 <sup>6</sup>				
New sealing requirements	Any participant who removes a seal without the relevant metering participant's knowledge must notify that metering participant of the removal and reason for it					5,000	5 <sup>10</sup>			
	AND Control devices are to be sealed (on the next occasion when the metering installation is visited for (re)certification or inspection)						2 <sup>11</sup>			
	AND Main switch covers are to be sealed (on the next occasion when the metering installation is visited for (re)certification or inspection)						2 <sup>12</sup>			
New process for inaccurate or defective metering equipment	Any participant, upon becoming aware of reasonably suspected inaccurate or defective metering equipment, must notify the relevant metering participant unless they have evidence that reasonably leads them to believe the relevant metering participant has already been notified	400		400		400	5 <sup>13</sup>			
	AND Any metering participant who receives a notification must take reasonable steps to investigate the suspected inaccuracy/defect			1,600	250 <sup>7</sup>					
Clarification of details of event logs	Phase failure to be a minimum requirement of event logs (except where separate meter and data loggers prevent this)									
Changes to maintenance of network supply point mapping table	New procedure for maintaining network supply point mapping table and making information available to participants							5,000		

<i>Benefits</i>										
Changes to inspection requirements	Remove the inspection requirements on category 1 metering installations				3.50 <sup>8</sup>					
	AND	Reduced inspection requirement from every one year to every 2.5 years for category 4 metering installations			180 <sup>8</sup>					
	AND	Reduced inspection requirement from every one year to every 1.5 years for category 5 and 6 metering installations			100 <sup>8</sup>					
Changes to in-situ recalibration	Create provisions to allow for in-situ recalibration of low voltage category 3 metering installations				60 <sup>8</sup>					
Changes to maintenance of network supply point mapping table	New procedure for maintaining network supply point mapping table and making information available to participants								7,500	
Efficiency benefits resulting from greater compliance of metering installations enabling more accurate billing and reconciliation										1,750,000

Notes:

- <sup>1</sup> \$0.10 per meter reading for 12 meter readings per year, per meter interrogated manually, with the percentage of meters interrogated manually modelled as declining over time.
- <sup>2</sup> Assuming 75% of metering participants do not already have ISO certification.
- <sup>3</sup> For 1,000 covers across all metering participants.
- <sup>4</sup> Per standard promoted, assuming one standard promoted per year across all metering participants.
- <sup>5</sup> Per instance, assuming 12 instances per year across all metering participants.
- <sup>6</sup> Per metering installation; the difference between the average discounted value of \$300 inspection cost sometime over first 10 years and average discounted value sometime over first five years.
- <sup>7</sup> Per new notification, assuming 50 new notifications per year across all metering participants.
- <sup>8</sup> Per metering installation per year; assumes 75% of category 3 metering installations are less than 1 kV.
- <sup>9</sup> Per affected meter, assuming 1,000 affected meters per year across all ATHs.
- <sup>10</sup> Per instance, assuming 1,000 instances per year across all ATHs.
- <sup>11</sup> Per metering installation, assuming 85% of metering installations have control devices and 25% of these are not already sealed, and 130,000 metering installations are visited each year for certification, recertification or inspection.
- <sup>12</sup> Per metering installation, assuming 66% of metering installations have main switch covers and 50% of these are not already sealed, and 130,000 metering installations are visited each year for certification, recertification or inspection.
- <sup>13</sup> Per notification, assuming 100 notifications per year across all ATHs.
- <sup>14</sup> Assuming one successful rule change every two years.

Source: Industry Reference Group, industry submissions, Electricity Commission, NZIER

### 2.4.1 Efficiency benefits

Greater compliance of metering installations and more accurate metering information would enable more accurate quotation, billing and reconciliation. These in turn would result in more accurate allocation of costs between market participants, including consumers.

The direct effect of more accurate allocation of costs to the correct market participants would be a transfer from participants who are being charged or paid too much currently to those who are being charged or paid too little currently. There is likely to be an imbalance in the extent of under and over charging and under and over paying, as participants are more likely to complain about being overcharged or underpaid than undercharged or overpaid. If the net balance written off currently due to non-compliance of metering installations and inaccurate metering information were equivalent to around 1% of New Zealand's total annual electricity generation of 42,245 GWh<sup>3</sup>, at an average price of \$75/MWh, this would amount to a loss of around \$32 million per year. As simply a transfer between market participants, however, the direct effect of more accurate allocation of costs in reducing the extent of this loss would constitute no net benefit to the market as a whole, regardless of how much the preferred options reduced this loss.

Indirectly, however, more accurate allocation of costs between participants would promote a more efficient market for electricity. Under more accurate quotation, billing and reconciliation, participants would have greater certainty about the actual costs and benefits to them of buying and selling electricity and greater confidence that they would secure the actual net benefits of the electricity they supplied or demanded. These may stimulate an increase (or decrease) in the amount of electricity they are willing to supply or demand and increase competition. Increased competition between participants would exert downward pressure on the sale price and supply cost of electricity and enhance the incentive to pursue future cost reductions, to avoid losing business to competing participants.

The consequence of better market information is therefore better – in terms of more economically efficient – production and consumption decisions, where the three components of economic efficiency are:

- allocative efficiency – the price and quantity of electricity supplied
- productive efficiency – the cost of supplying electricity and
- dynamic efficiency – investment and innovation to pursue reduction over time in the cost of supplying electricity.

The magnitudes of efficiency benefits resulting from greater compliance of metering installations and more accurate metering information are unknown. For the purpose of assessing whether the benefits of the preferred options are likely to outweigh the costs, we model the potential efficiency benefits as follows.

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<sup>3</sup> Ministry of Economic Development (2009) New Zealand Energy Data File, Tables G.2a and G.3b.

If more accurate allocation of costs between market participants as a result of moving responsibility for compliance of metering installations to metering participants resulted in a reduction in the price at which electricity is supplied by, say, 1%, at an average price of around \$75/MWh, this would reduce the average price by \$0.75/MWh. For existing demand, this reduction in price is simply a transfer from producers to consumers, resulting in no net benefit. Under a price elasticity of demand of  $-0.26^4$ , a 1% reduction in price would increase demand by 0.26%, which would be an additional 110 GWh per year. For this additional demand, there is a benefit to additional consumers who did not consume electricity at the previous higher price, in the form of a “consumer surplus” of half<sup>5</sup> the price reduction, applied across the increase in quantity demanded. This suggests an allocative efficiency benefit to the market of around \$40,000 per year.

More accurate allocation of costs would also promote productive efficiency through greater certainty about costs and increased competition between market participants improving the efficiency with which electricity is produced and supplied. Unlike the immediate allocative efficiency benefits above, improvements to production and supply processes are likely to take time to develop and implement. If this effect of moving responsibility for metering installation compliance to metering participants lowered the average unit cost of supplying electricity by, say, \$0.05/MWh (equivalent to 0.072% of the price of electricity, at an average price of around \$75/MWh), phased in over five years, this suggests a productive efficiency benefit market wide, across total electricity supply, averaging around \$1.710 million per year over the time horizon of the CBA.

Together, these imply total static efficiency benefits from moving compliance responsibility to metering participants of on average \$1.750 million per year.

Over time, dynamic efficiency benefits have potential to far outweigh the above static efficiency improvements. These are much longer term, however, so we assume for simplicity that they are beyond the time horizon of the CBA.

We model the further increase in compliance from additionally introducing standards for certification and auditing of metering participants and enhancing standards for certification and auditing of ATHs, metering participant and ATH responsibilities and metering installation requirements as providing allocative and productive efficiency benefits of a further \$1.750 million per year, on average.

The IRG indicated improved access to metering information through enhancing the electricity registry as adding more to allocative and productive efficiency benefits – a further \$3.045 million per year, on average, equivalent to a 1.55% reduction in average price and 0.124% reduction in average unit cost of electricity.

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<sup>4</sup> Sinclair Knight Merz (2005) *National Cost Benefit Analysis of Proposals to Take Water from the Waitaki River*, final report to Ministry of Economic Development, Appendix H.

<sup>5</sup> To give the area of the consumer surplus triangle formed by the intersection of the demand and supply curves.

Note that these are conservative estimates, for the purpose of assessing whether the benefits of the preferred options are likely to be sufficient to exceed the costs. The actual allocative and productive efficiency benefits could well be larger. The efficiency benefits are, however, the greatest uncertainty in the CBA. In the sensitivity analysis, we test how small these efficiency benefits could be for the preferred options to break even.

## 2.5 Number of market participants

We multiply the above costs and benefits per participant by the number of market participants to whom they apply. The market currently comprises 28 distributors, seven traders (generators/retailers), 10 major metering participants, at least 50 metering installation component owners and 23 approved test houses. At the last count, metering installations numbered 1,950,001. Establishing a central database by enhancing the electricity registry is modelled as impacting significantly on only three of the metering participants, whilst introducing and enhancing standards for certification, auditing, responsibilities and requirements is modelled as impacting significantly on the 10 major metering participants plus a further 10 smaller metering participants. The preferred options also have cost implications for the Commission.

For the purpose of comparing the costs and benefits of the preferred options, we assume these numbers of market participants to remain constant for the time horizon of the CBA.

## 2.6 Time horizon

Over coming months, the Commission will continue to work with market participants to develop and agree the detailed requirements under the proposed rule changes. It expects to seek ministerial approval of the new rules by late 2010 and, if approved, to complete implementation by mid 2011. The benefits of the preferred options are therefore expected to start flowing from mid 2011.

In the CBA, we model the costs and benefits of the preferred options over a period of 10 years from 2009/10 to 2018/19 (in June years). This time horizon seeks to capture enough of the ongoing costs and benefits after the initial development and implementation costs to provide a robust assessment of the preferred options. We do not extend the CBA beyond 10 years as further new metering technologies could be expected to be developed by this time, necessitating further changes to the regulatory regime.

So that we can compare directly costs and benefits occurring at different points in time, we adopt a discount rate of 10% to convert future costs and benefits to their present values in 2009. In the sensitivity analysis, we also model discount rates of

6%, to reflect a public policy perspective, and 12%, to reflect a commercial perspective<sup>6</sup>.

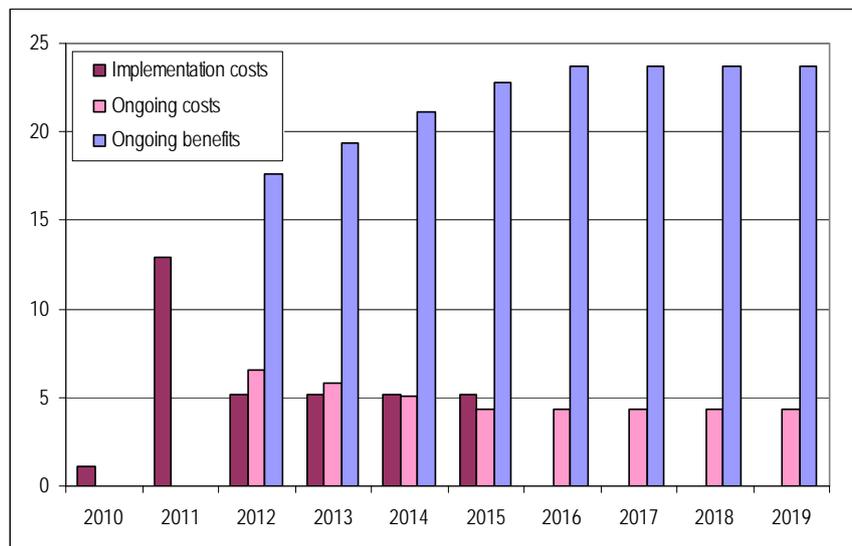
## 3. Results

### 3.1 Annual costs and benefits

Figure 1 shows our estimates of the total annual costs and benefits of the proposed rule changes for the preferred options, across all market participants. Although initial implementation costs are considerable, once implemented, the proposed rule changes deliver over five times as much in ongoing benefits as they incur in ongoing costs. Initial implementation costs total \$34.7 million over six years, ongoing benefits almost \$23.7 million per year and ongoing costs almost \$4.4 million per year.

**Figure 1 Annual costs and benefits – total proposed rule changes**

\$ million, year ending June



Source: NZIER

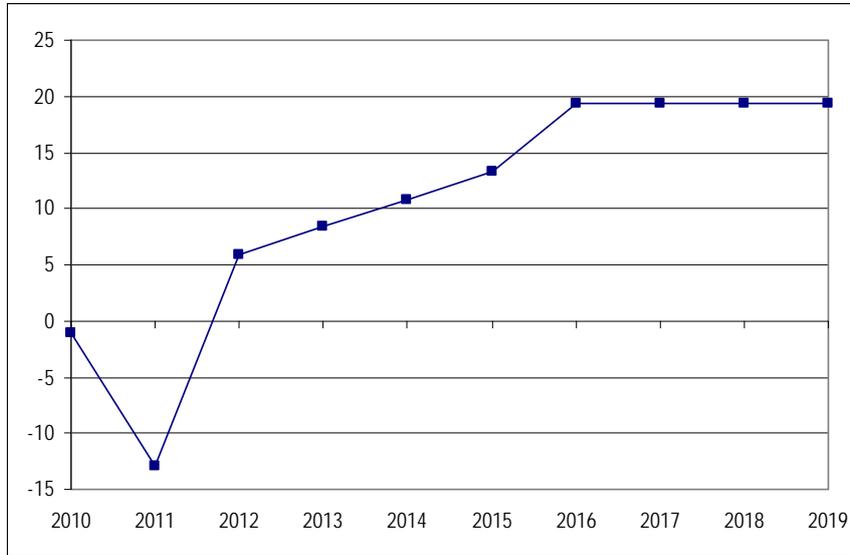
Following implementation, the ongoing net benefits therefore stabilise at \$19.3 million per year, as shown in Figure 2.

The total annual costs and benefits of each of the preferred options are shown in Figure 3 to Figure 6. Despite incurring the largest implementation costs, once implementation is complete, requiring certification of load control devices used for settlement purposes delivers the greatest ongoing annual net benefits, as shown in Figure 7.

<sup>6</sup> Treasury now recommends an 8% real discount rate for energy and water infrastructure projects. This is covered by the range we model in the sensitivity analysis.

**Figure 2 Annual net benefits – total proposed rule changes**

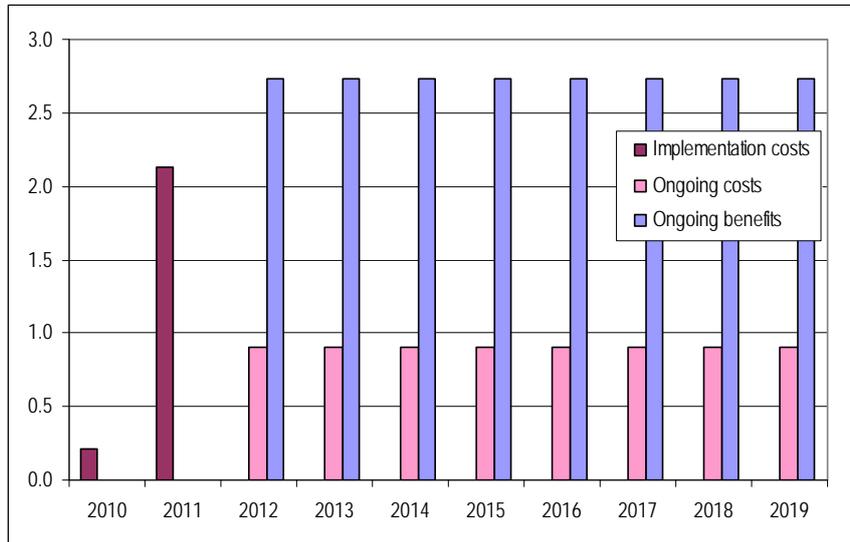
\$ million, year ending June



Source: NZIER

**Figure 3 Annual costs and benefits – move responsibility for metering installation compliance to metering participants**

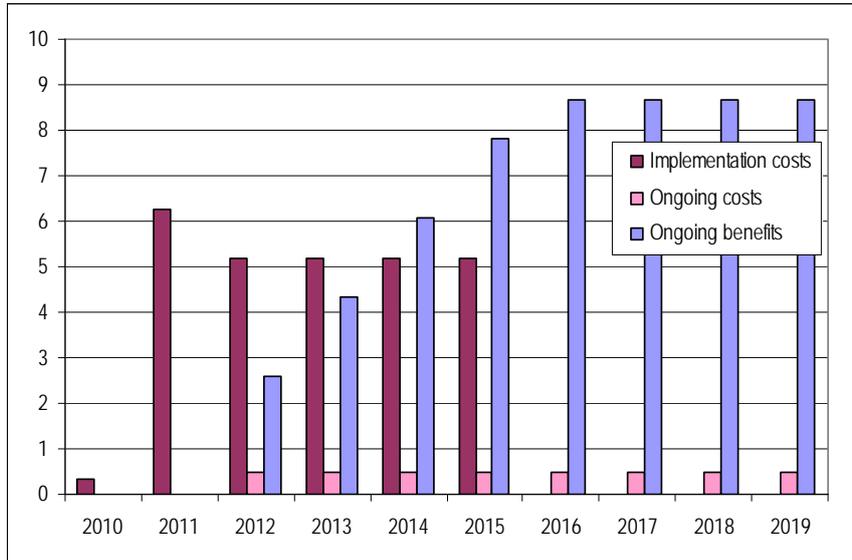
\$ million, year ending June



Source: NZIER

**Figure 4 Annual costs and benefits – require certification of load control devices used for settlement purposes**

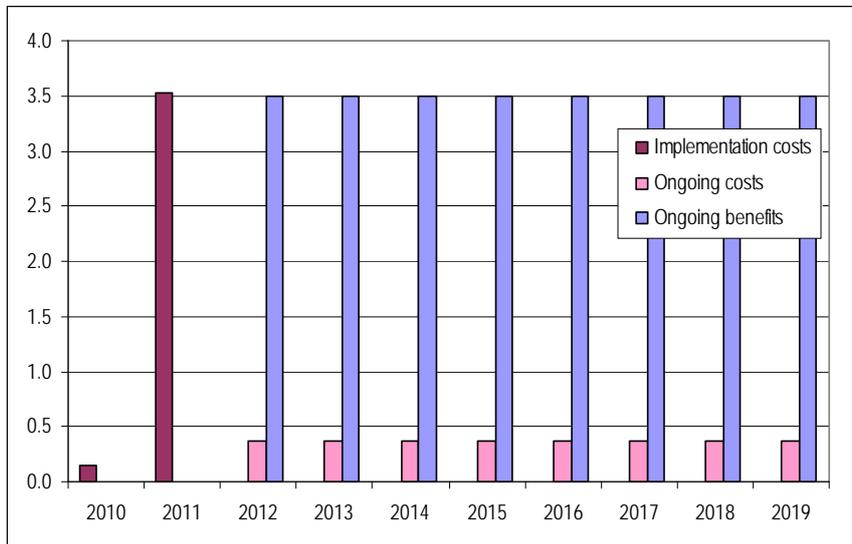
\$ million, year ending June



Source: NZIER

**Figure 5 Annual costs and benefits – establish central database by enhancing the electricity registry**

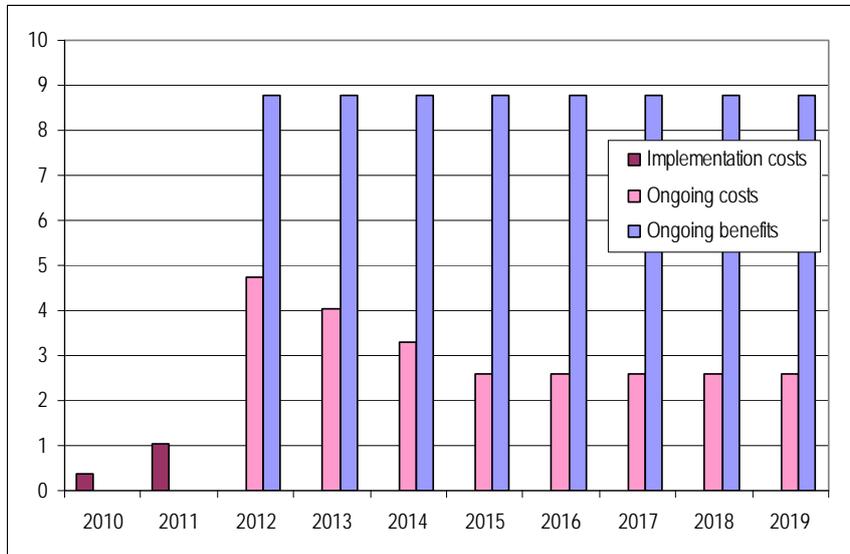
\$ million, year ending June



Source: NZIER

**Figure 6 Annual costs and benefits – introduce and enhance standards for certification, auditing, responsibilities and requirements**

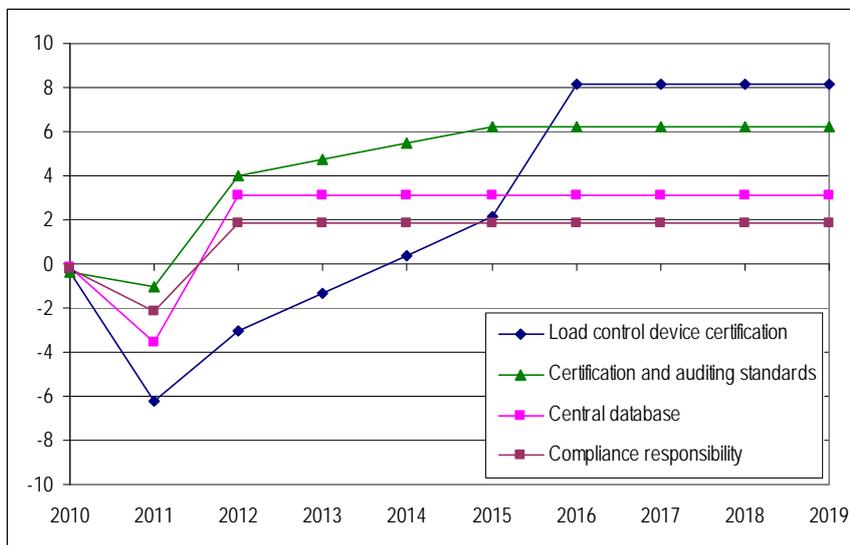
\$ million, year ending June



Source: NZIER

**Figure 7 Annual net benefits – by preferred option**

\$ million, year ending June



Source: NZIER

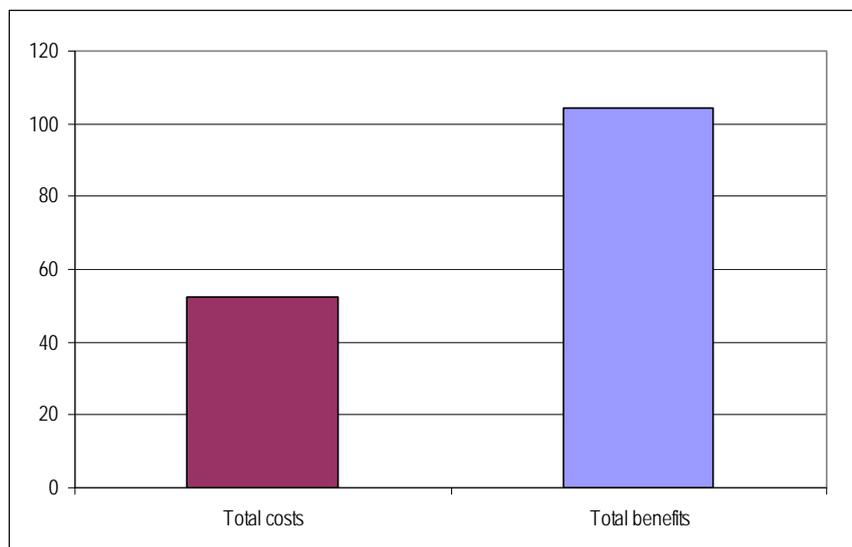
### 3.2 Total costs and benefits

With discounting to reflect their relative timing, the above annual costs and benefits imply present value total costs over 2009/10 to 2018/19 of \$52.3 million and present value total benefits of \$104.3 million, as shown in Figure 8. The proposed rule

changes, in total, therefore deliver estimated net benefits of \$52.0 million over the next 10 years, across all market participants. For each dollar of cost, they are estimated to return \$1.99 in benefits. In total, they would break even by mid 2014.

**Figure 8 Present value total costs and benefits – total proposed rule changes**

\$ million , 2009/10 to 2018/19



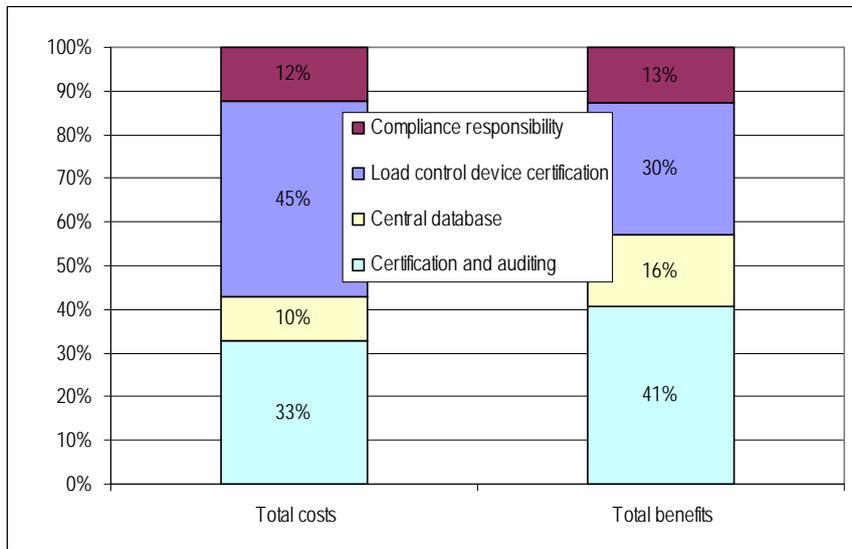
Source: NZIER

Requiring certification of load control devices used for settlement purposes accounts for almost half the present value total costs of the proposed rule changes over the next 10 years, but also almost a third of the benefits, as shown in Figure 9. Introducing and enhancing standards for certification, auditing, responsibilities and requirements incurs a third of the costs and delivers over two fifths of the benefits. Moving responsibility for metering installation compliance to metering participants and establishing a central database by enhancing the electricity registry are the least costly of the preferred options, but also provide the smallest benefits.

Nevertheless, each component of the proposed rule changes is estimated to deliver more in benefits than it costs, as shown in Figure 10. Moving responsibility for compliance of metering installations to metering participants generates present value net benefits of \$6.7 million over the next 10 years. Net benefits are \$8.1 million from requiring certification of load control devices used for settlement purposes, \$11.8 million from establishing a central database by enhancing the electricity registry and \$25.4 million from introducing and enhancing standards for certification, auditing, responsibilities and requirements. NZIER's previous CBAs of the shortlisted options in each of these four areas also showed the preferred options to deliver greater net benefits than the alternative options assessed in each of these four areas.

**Figure 9 Distribution of present value total costs and benefits**

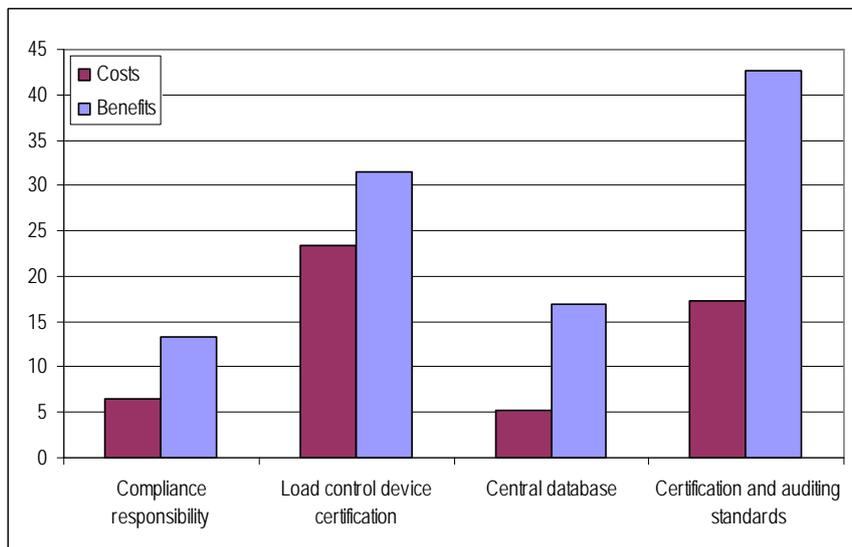
\$ million , 2009/10 to 2018/19



Source: NZIER

**Figure 10 Present value total costs and benefits – by preferred option**

\$ million , 2009/10 to 2018/19

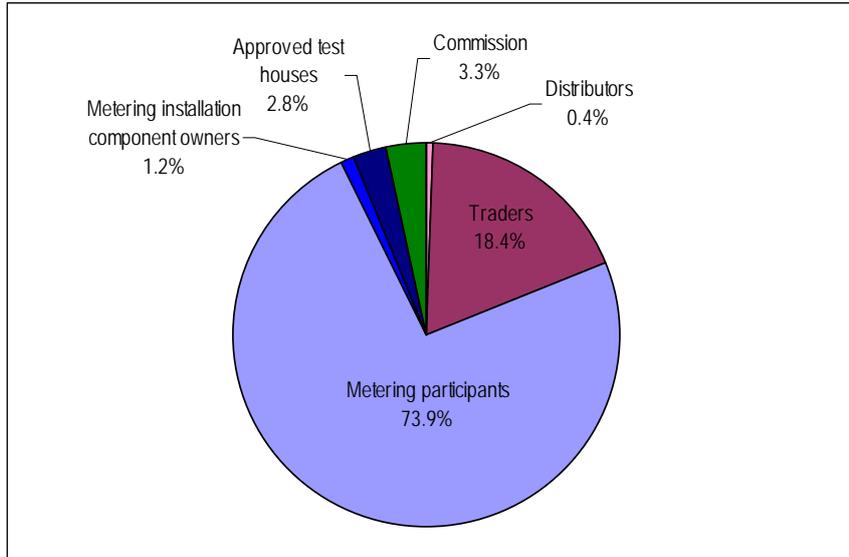


Source: NZIER

Metering participants bear three quarters of the present value total costs of the proposed rule changes over the next 10 years, as shown in Figure 11. As shown in Figure 12, they gain a quarter of the benefits directly as well as share in the market wide benefits.

**Figure 11 Distribution of present value total costs**

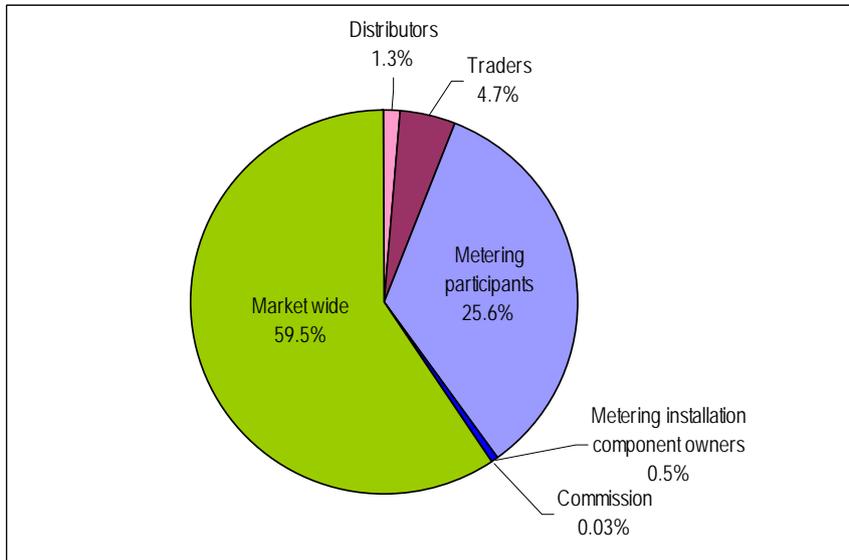
Percentage of total, 2009/10 to 2018/19



Source: NZIER

**Figure 12 Distribution of present value total benefits**

Percentage of total, 2009/10 to 2018/19



Source: NZIER

Of the market wide benefits, almost half are due to the deferral of investment expenditure enabled by greater compliance of load control devices resulting in increased reliability, availability and use of load control. Just over half derive from increased efficiency in the market for electricity due to greater compliance of metering installations and more accurate metering information resulting in more accurate allocation of costs between market participants.

### 3.3 Sensitivity analysis

As noted above, the unit costs and benefits modelled in the CBA reflect the opinions of the IRG, views expressed in industry submissions and the Commission's estimates. Given the uncertainty of these costs and benefits, we test the sensitivity of the main results presented above across a range of values for each type of cost and benefit. The results of this sensitivity analysis are shown in Table 5. This table shows how adopting a 10% or 25% lower or higher value for each unit cost and benefit. In turn, would alter the estimated present value total net benefits of the proposed rule changes for the preferred options over the next 10 years.

The present value net benefits of the proposed rule changes in total are most sensitive to, in descending order, the benefits of compliance cost savings from changes to metering installation inspection requirements, the costs of upgrading load control equipment, the benefits of deferring generation and transmission investment expenditure due to increased availability and use of load control and the efficiency benefits from more accurate quotation, billing and reconciliation due to enhancing the electricity registry to provide a central database of metering information.

If the certification of load control devices used for settlement purposes increased controllable load by just 10% (instead of the assumed 15%), the present value net benefits of this preferred option would be marginal at \$0.1 million and the present value net benefits of the proposed rule changes in total would be reduced to \$44.0 million. At a 5% increase in controllable load, the costs of this preferred option would outweigh the benefits by \$7.9 million and the present value net benefits of the proposed rule changes in total would be reduced to \$36.0 million.

Certification of load control devices used for settlement purposes carries the particular risk that load control devices not initially used for settlement purposes, and therefore not certified, subsequently become needed for settlement purposes at a later time, perhaps following a change of trader, and do then require certification. At a cost of \$50 per load control device for this subsequent certification, this reduces the present value net benefits of this preferred option to \$5.0 million and the present value net benefits of the proposed rule changes in total to \$48.8 million.

A 6% discount rate increases the present value net benefits of the proposed rule changes over the next 10 years to \$67.5 million, whilst a 12% discount rate reduces the present value net benefits to \$45.7 million.

Even if all of the implementation and ongoing costs of all of the proposed rule changes were 25% higher and all of the benefits 25% lower than modelled, the proposed rule changes would still deliver present value net benefits of \$12.9 million over the next 10 years (total benefits of \$78.2 million less total costs of \$65.3 million). This indicates that market participants can be confident that the proposed rule changes would provide significant net benefits over the status quo of retaining the existing regulatory requirements under the existing rules.

**Table 5 Sensitivity analysis**

Main results	Present value net benefits (\$ million)
Compliance responsibility	6.718
Load control device certification	8.113
Central database	11.805
Standards for certification, auditing, responsibilities and requirements	25.354
Total proposed rule changes	51.991

Sensitivity analysis	Present value net benefits (\$ million)			
	-25%	-10%	10%	25%
<b>Compliance responsibility</b>				
<i>Costs</i>				
Develop and agree detailed requirements	6.797	6.750	6.687	6.639
Negotiate contracts	7.179	6.902	6.534	6.258
Co-ordinate and deal with MCOs	7.325	6.961	6.476	6.112
Comply with metering participants' requirements	6.840	6.767	6.670	6.597
Compliance and audit processes	7.021	6.840	6.597	6.415
Monitor and enforce compliance	6.779	6.743	6.694	6.658
<i>Benefits</i>				
Time saving from single point of contact for compliance issues	6.379	6.583	6.854	7.058
Time saving in dealing with mixed ownership metering installations	6.082	6.464	6.973	7.355
Reduced costs of compliance and audit processes	6.506	6.633	6.803	6.931
Efficiency benefits resulting from greater compliance of metering installations enabling more accurate billing and reconciliation	4.597	5.870	7.567	8.840
<b>Load control device certification</b>				
<i>Costs</i>				
Develop and agree detailed requirements	8.241	8.164	8.062	7.986
Upgrade existing load control equipment	12.852	10.009	6.218	3.375
Standardise systems and standards for load control	8.216	8.154	8.072	8.011
Upgrade load control field devices	8.284	8.182	8.045	7.943
Amend systems and processes to gather and store required data	8.216	8.154	8.072	8.011
Testing, certification, auditing and record keeping	8.659	8.332	7.895	7.568
Monitor and enforce compliance	8.168	8.135	8.092	8.059
<i>Benefits</i>				
Fewer failures in facilitating existing load control, enabling lower peak loads and tariffs and therefore deferral of investment expenditure	6.517	7.475	8.752	9.710

Time saving in checking that relays that switch tariffs are working correctly	8.050	8.088	8.139	8.177
Time saving in managing tariff changes for customers	8.050	8.088	8.139	8.177
Time saving from fewer customer complaints about incorrect tariffs due to fewer failures in facilitating load control	7.955	8.050	8.177	8.272
Increased availability and use of load control, enabling further reductions in peak loads and tariffs and therefore further deferral of investment expenditure	2.126	5.718	10.508	12.204
<b>Central database</b>				
<i>Costs</i>				
Develop and agree detailed requirements	11.858	11.826	11.784	11.753
Upgrade Commission's electricity registry	11.907	11.846	11.764	11.703
Implementation and integration	12.282	11.996	11.614	11.328
Electricity registry operation and licensing	11.866	11.829	11.781	11.744
Data maintenance	12.012	11.888	11.722	11.598
Compliance and audit	11.926	11.854	11.757	11.684
Monitoring of metering participant compliance	11.866	11.829	11.781	11.744
<i>Benefits</i>				
Time saving in investigating sites to obtain accurate metering information	11.684	11.757	11.854	11.926
Time saving from fewer customer complaints	11.593	11.720	11.890	12.017
Lower costs of compliance and audit for retailers	11.593	11.720	11.890	12.017
Efficiency benefits from improved accuracy at time of switch and post switch, enabling more accurate quotation, billing and reconciliation	8.113	10.328	13.282	15.497
<b>Standards for certification, auditing, responsibilities and requirements</b>				
<i>Costs</i>				
Develop and agree detailed requirements	25.488	25.408	25.301	25.221
Implementation	25.550	25.432	25.276	25.159
Non-invasive checks for manual interrogation	27.067	26.040	24.669	23.642
Other additional annual compliance costs	27.623	26.262	24.447	23.086
<i>Benefits</i>				
Compliance cost savings	16.828	21.944	28.765	33.880
Efficiency benefits	23.233	24.506	26.203	27.476
<b>Total proposed rule changes</b>				
Implementation costs	58.937	54.769	49.213	45.046
Ongoing costs	58.113	54.440	49.542	45.869
Ongoing benefits	25.926	41.565	62.417	78.057

Source: NZIER