

Regulatory Impact Statement

Electricity Safety (Bushfire Mitigation) Regulations 2013

February 2013

**Prepared for Energy Safe Victoria by
Jaguar Consulting Pty Ltd**



Victorian
Competition & Efficiency
Commission

Level 37, 2 Lonsdale Street
Melbourne Vic 3000

GPO Box 4379
Melbourne Vic 3001

T (03) 9092 5800
F (03) 9092 5845

E contact@vcec.vic.gov.au
www.vcec.vic.gov.au

25 February 2013

Roanne Allan
Policy Advisor
Energy Safe Victoria
Level 5, Building 2, 4 Riverside Quay
SOUTHBANK VIC 3006

Dear Ms Allan

ADVICE ON THE ADEQUACY OF REGULATORY IMPACT STATEMENT

Thank you for seeking advice on the Regulatory Impact Statement (RIS) on the proposed *Electricity Safety (Bushfire Mitigation) Regulations 2013*.

The Victorian Competition and Efficiency Commission (VCEC) advises on the adequacy of RISs as required under section 10(3) of the *Subordinate Legislation Act 1994* (the Act). I advise the final version of the RIS received by the VCEC on 25 February 2013 meets the requirements of section 10 of the Act.

The VCEC's advice is based on the adequacy of the evidence presented in the RIS and is focused on the quality of the analysis rather than the merits of the proposal itself. **Therefore, the VCEC's advice the RIS is adequate does not represent an endorsement of the proposal.**

In the interests of transparency, it is government policy VCEC's advice be published with the RIS when it is released for consultation.

If you have any questions, please contact RegulationReview@vcec.vic.gov.au.

Yours sincerely

Andrew Walker

Assistant Director

Victorian Competition and Efficiency Commission

Summary

Nature of the proposed regulations

The Electricity Safety (Bushfire Mitigations) Regulations 2003 are due to sunset in June 2013. The proposed regulations are intended to re-make the existing regulations with limited amendments. The main substantive provisions of the regulations are that they specify the required content of the Bushfire Management Plans that Major Electricity Companies and Specified Operators must submit to Energy Safe Victoria and that they require the inspection of electrical transmission and distribution equipment located in hazardous bushfire risk areas by qualified inspectors at least every 37 months.

The ***Electricity Safety Act 1998*** imposes a general duty on certain owners of electrical infrastructure, including in hazardous bushfire risk areas, to minimise the risk of bushfire ignition due to failures of this infrastructure. The Act also requires these parties to prepare, and have accepted by Energy Safe Victoria (ESV), Bushfire Mitigation Plans (BMP), which set out the policies, strategies and other actions that they will take in order to comply with this general duty. The Electricity Safety (Bushfire Mitigation) Regulations 2003 set out specific requirements in relation to the content of BMP. The regulations also implement, from 2010, two specific recommendations of Victorian Bushfires Royal Commission (VBRC). In response to identified inadequacies in respect of then current inspection and maintenance arrangements for electricity assets, the VBRC recommended that the State (through Energy Safe Victoria) require electricity distribution businesses to:

- inspect all single-wire earth return (SWER) lines and all 22-kilovolt feeders in areas of high bushfire risk at least every 3 years; and
- review and modify practices, standards and procedures for the training and auditing of asset inspectors to ensure that registered training organisations provide adequate theoretical and practical training for asset inspectors.

The regulatory inspection requirements arising from the implementation of these recommendations are clearly prescriptive in nature, in contrast to the general format of the BMP requirement and most of the broader provisions of the Electricity Safety Act. However, the VBRC believed that this approach was necessary to provide a high level of assurance that the inadequacies in past performance in these areas would be addressed in the future through more frequent and higher quality inspection arrangements. The proposed regulations would retain these requirements.

Rationale for regulation

Above-ground electricity lines are a significant contributor to bushfire risk. While only a relatively small proportion of bushfires are ignited by electricity asset failure, these ignitions tend to occur when fire conditions are worst, so that fires ignited by electricity assets are responsible for a substantial proportion of the overall damage caused by bushfire. Around half of the fires occurring during each of

the last four major fire events in Victoria - those of 1969, 1977, 1983 and 2009 - were ignited by electricity asset failures. Based on estimates of the long-term incidence of major bushfires in Victoria and the costs of these fires, it is estimated that the average annual cost to Victoria of major bushfires ignited due to electricity asset failures is around \$60 million. These costs are incurred despite the considerable risk reduction expenditures undertaken by electricity transmission and distribution businesses, particularly in pruning trees and other vegetation to prevent contact with electricity infrastructure and in conducting targeted maintenance to prevent asset failure.

The VBRC documented the causes of the Black Saturday bushfires and concluded that a substantial proportion were ignited due to failures of electricity assets. As noted above, it identified inadequacies in the then-current inspection regime and recommended the adoption of prescriptive elements within the regulations in order to specify minimum qualifications standards for inspectors and minimum inspection frequencies. These were adopted in 2010 via amending regulations and are proposed to be retained in the replacement regulations that are the subject of this RIS.

These prescriptive inspections requirements account for by far the largest part of the costs associated with the proposed regulations. By contrast, based on data received from electricity distribution businesses, the cost of preparing, submitting and modifying BMP is modest: the total costs of these activities are estimated to total approximately \$30,000 per annum for all affected parties, or \$0.25 million in present value terms over the expected 10 year life of the proposed regulations.

Given that the great bulk of the costs associated with the existing regulations result from the prescriptive inspection requirements, the consideration of options undertaken in the course of determining what regulations would be adopted to replace them has focused on this issue. Five options were considered, as follows:

- Remake the existing regulations with no change to the inspection requirements in HBRA;
- Apply the 37 month inspection frequency requirements only to Single Wire Earth Return (SWER) lines and 22kV feeder lines, as recommended by the VBRC;
- Vary the required inspection frequency with asset age, with a minimum frequency of 2.5 years for assets older than 20 years and 5 years for younger assets;
- Vary the required inspection frequency with asset age, with a minimum frequency of 37 months for assets older than 20 years and 5 years for younger assets; and
- Specify minimum qualifications requirements for inspectors only, without prescribing a minimum inspection frequency.

Table S1, below, summarises the cost implications of these five options. In each case, the incremental costs are identified, measured against a "business as usual" base case, as identified by the affected organisations in the context of a questionnaire administered during 2011.

Table S1: Comparative cost estimates of the identified options

	BAU	Incremental ¹	Incremental (%)	PV (10 years) of Incremental costs	Total annual costs	BEA - required % reduction in bushfire cost
Proposed Regulations	\$8,861,700	\$3,591,249	40.5%	\$29.9 million	\$12,452,949	6.0%
Alternative 1	\$8,861,700	≈ \$3,591,249	≈ 40.5%	≈ \$29.9 million	≈ \$12,452,949	6.0%
Alternative 2	\$8,861,700	\$3,208,283 - \$4,824,091	36.2% - 54.1%	\$26.7 - \$40.1 million	\$11,981,506 - \$13,685,791	5.3% - 8.0%
Alternative 3	\$8,861,700	> \$2,557,654	28.6%	> \$21.3 million	\$11,419,354	> 4.3%
Alternative 4	\$8,861,700	> \$1,098,800	12.4%	> \$9.1 million	\$9,960,500	>1.8%

Table S1 shows that the BAU costs of inspecting electrical infrastructure in HBRA total around \$8.9 million per annum. The least costly option, Alternative 4, would add around \$1.1 million or 12.4% to these annual costs, while the remaining options would add up to \$4.8 million, or 54.1%, to these BAU costs. A number of caveats must be noted in respect of these cost estimates, however:

- Costs under alternative 4 are likely to be somewhat higher than the minimum figure highlighted as, it is considered unlikely that the affected parties would reduce inspection frequencies to the previous levels even were the currently prescribed inspection frequencies not to be retained;
- Costs under alternative 3 are likely to be higher than the figure indicated as it will in many areas not be possible to clearly delineate which assets are less than 20 years old. Hence, differentiating inspection frequencies will often not be feasible in practice;
- the cost of alternative 2 is likely to be toward the upper end of the indicated range, for the same reason; and
- the cost of Alternative 1 may be slightly less than that estimated, if inspection frequencies could be differentiated in this context. However, there will again be many circumstances where this is not feasible.

¹ Incremental cost figures include the cost of preparing and submitting BMP, as well as the costs to ESV of assessing and accepting draft BMP. As discussed in Section 5, these costs represent a very small proportion of the total incremental costs of the regulations, with annual costs to MECs/SOs being estimated at around \$30,000 and similar annual costs being incurred by ESV.

Table S1 also identifies the reduction in bushfire related costs that would be required in order to offset the identified costs of each option and yield a positive net benefit. The required reductions range from 1.8% for Alternative 4 to as much as 8.0% for Alternative 2. In the case of the proposed regulations, the required reduction is 6.0%. While the standards contained in the proposed regulations have essentially been in place since 2010, it is not currently possible to observe changes in bushfire ignition frequencies and costs. However, these changes are expected to be observable prior to the sunseting of the proposed regulations.

There are significant uncertainties as to the relative effectiveness of the different options in reducing bushfire ignition. These derive from uncertainties as to both the asset age profile and the relationship between age and probability of asset failure. Moreover, there is also uncertainty as to the relative effectiveness of improving the qualifications of inspectors and increasing inspection frequencies. Given these factors, it is not possible to compare the proposed regulations and the identified alternatives in fully quantified terms. Consequently, a Multi-Criteria Analysis has been undertaken. Three criteria have been identified, consistent with the underlying objectives of the proposed regulations. These are:

- The ability of the proposal to reduce bushfire risks arising from electricity asset failure;
- The substantive compliance costs of implementing the proposal; and
- The administrative burdens imposed by the proposal.

Thus, the first, of these criteria relates to the benefits attributable to the various alternatives, while the second and third relate to the costs they would impose. Given that there are two cost criteria and one benefit criterion, it is necessary to weight the criteria in order to provide a balanced assessment. This means that the total weight given to the two cost criteria must equal that of the benefit criterion. Substantive compliance costs are, where quantifiable, generally found to be significantly larger than administrative burdens. Hence, the substantive criterion has been weighted significantly more heavily than the administrative costs criterion.

Consistent with the above considerations, the following weights have been assigned to the criteria:

- Ability to reduce bushfire risks: 1.0
- Substantive compliance costs: 0.8
- Administrative burdens: 0.2

Each option has been assigned a score on a scale of - 10 to + 10 for each criterion. Scoring is undertaken against the base case of not remaking the sunseting regulations. Thus, a negative score indicates that the option is less preferred to the base case on this criterion, while a positive score indicates that it is more preferred. Table S2 summarises the scoring of each option against these three criteria.

Table S2: Multi-criteria analysis of feasible alternatives

	Proposed regulations	Limit 3 yr inspection requirement to SWER & 22kV lines	Variable inspection frequencies (2.5 yr/5 yr)	Variable inspection frequencies (37 month/5 yr)	Qualifications regulated only
Reduction in bushfire risk	+8 x 1 = + 8	+7 x 1 = + 7	+9 x 1 = + 9	+ 7 x 1 = +7	+ 4 x 1 = + 4
Substantive compliance cost	- 6 x .8 = -4.8	- 6 x .8 = -4.8	- 6 x .8 = -4.8	- 4 x .8 = - 3.2	- 2 x .8 = - 1.6
Administrative burden	+ 4 x .2 = +.8	+4 x .2 = +.8	-2 x .2 = - .4	- 2 x .2 = - .4	0
Total	+ 4.0	+ 3.0	+ 3.8	+ 3.4	+ 2.4

The fact that all five alternatives receive positive scores indicates that all are preferable to the base case of not replacing the sunseting regulations. The scores received by the five options are also relatively similar, ranging from a low of 2.4 to a high of 4.0, indicating that the practical differences between them are relatively small. This result, in which three alternatives in particular all receive very similar scores, reflects the fact that despite being formally quite distinct, consultation with regulated parties and observation of past practice has demonstrated that the actual response to these three alternatives would be very similar. Thus, for example, three alternatives (the proposed regulations and options 1 and 2) were all rated identically in terms of substantive compliance cost, because it is expected that the inspection arrangements that would be adopted in response to each alternative would be essentially identical.

The proposed regulations score highest, with 4.0 points. This reflects the fact that they receive the joint highest score in relation to compliance costs and administrative burdens, while receiving the second highest score on the reduction of bushfire risk criterion. Option 2, involving variable inspection frequencies, with a 2.5 year frequency for older assets and a 5 year frequency for those younger than 20 year, scores next highest with 3.8 points. This option scores highest on the criterion of reduction in bushfire risk, but scores poorly in relation to administrative burdens.

However, a difficulty in respect of the above analysis must be acknowledged. It has been assumed implicitly that, in the absence of regulations explicitly requiring a set 37 month maximum inspection cycle and specified qualifications criteria for inspectors, ESV practice in assessing and approving proposed BMP would be unchanged from the position prior to 2009. In practice, this is highly unlikely. The combination of community expectation and the government's commitment to implementing the VBRC recommendations, including those relating to the frequency and quality of asset inspections, implies strongly that, even in the absence of explicit regulatory requirements, there would be significant pressure on ESV to do all that it could within the existing statutory framework to require the affected bodies to implement improved inspection practices. To the extent that changes to current

arrangements are considered likely to follow due to these dynamics, it is clear that the above will tend to over-estimate both the benefits and the costs of the proposed regulations.

Finally, the current regulatory context must be acknowledged. The proposed regulations largely mirror the position that has been in place since 2010. Moreover, the community has had a strong expectation that the recommendations of the VBRC will be implemented in practice. This implementation has been met and, indeed, slightly exceeded, insofar as the 37 month inspection regime has been applied universally to at risk assets, rather than only to SWER and 22kV lines. In this context, a move to options that would be seen as less rigorous than those currently in place would be likely to prompt a negative community response.

Given the above factors, ESV intends to proceed with the making of the proposed regulations.

Contents

1.	Introduction	9
2.	Objectives of the proposed regulations	10
3.	Nature and extent of the problem	11
3.1.	Bushfire ignition and electricity assets	11
3.2.	The costs of bushfires	22
3.3.	Market failure issues	27
4.	Summary of the proposed regulations	31
5.	Expected costs of the proposed regulations	33
5.1.	Preparation of Bushfire Management Plans	33
5.1.1.	<i>Data sources and approaches</i>	33
5.1.2.	<i>Cost of BMP preparation - Major Electricity Companies</i>	33
5.1.3.	<i>Cost of BMP Preparation - Specified Operators</i>	35
5.1.4.	<i>Cost of assessment and acceptance of BMP</i>	37
5.2.	Inspection requirements	37
5.2.1.	Data sources and approaches	38
5.3.	Incremental costs: electricity distribution businesses	38
5.4.	Costs to specified operators	44
5.5.	Cost summary	47
6.	Expected benefits of the proposed regulations	50
6.1.	Overview	50
6.2.	Break-even analysis	54
7.	Identification and analysis of feasible alternatives	57
7.1.	Alternative 1: Applying a maximum inspection frequency of three years only to SWER lines and 22kV feeder lines	58
7.2.	Alternative 2: Age-adjusted inspection frequency using 2.5 yearly inspection for assets 20 years and older and 5 yearly inspection for younger assets	61
7.3.	Alternative 3: Age-adjusted inspection frequency using a 37 monthly inspection for assets 20 years and older and 5 yearly inspection for younger assets	65
7.4.	Alternative 4: improve inspection quality without mandating inspection frequency	67
8.	Conclusion	70
8.1.	Overview and break-even analysis	70
8.2.	Multi-criteria analysis	75
9.	Implementation, monitoring and enforcement	81
10.	Evaluation strategy	84
11.	Regulatory Change Measurement Assessment	85
12.	Consultation	87
13.	Statement of compliance with National Competition Policy	90
	Appendix 1: Proposed Electricity Safety (Bushfire Mitigation) Regulations 2013	92

1. Introduction

The Electricity Safety (Bushfire Mitigations) Regulations 2003 are due to sunset in June 2013. The proposed regulations are intended to re-make the existing regulations with limited amendments.

The Electricity Safety Act 1998 requires Major Electricity Companies and Specified Operators to prepare Bushfire Mitigation Plans (BMP) which set out the actions that they will take to mitigate the risk of bushfire ignition due to failures in electricity assets (mainly comprising poles and wires networks) for which they are responsible. The Electricity Safety (Bushfire Mitigation) Regulations 2003 set out specific requirements in relation to the content of BMP. The BMP is expected to constitute the basis for a systematic program of asset monitoring and maintenance to be undertaken. Thus, in general terms, this is an example of "process based" regulation.

Amendments to the regulations which took effect in October 2010 implemented two specific recommendations from the Victorian Bushfires Royal Commission (VBRC). The VBRC had identified a number of inadequacies in respect of then current inspection and maintenance arrangements for electricity assets in high fire risk areas and made recommendations for improved practice in this area. In response to these, it recommended that the State (through Energy Safe Victoria) require electricity distribution businesses to:

- inspect all single-wire earth return (SWER) lines and all 22-kilovolt feeders in areas of high bushfire risk at least every 3 years; and
- review and modify practices, standards and procedures for the training and auditing of asset inspectors to ensure that registered training organisations provide adequate theoretical and practical training for asset inspectors.

These provisions are clearly prescriptive in nature, in contrast to the general format of the BMP requirement and most of the broader provisions of the Electricity Safety Act. However, the VBRC believed that this approach was necessary to provide a high level of assurance that the inadequacies in past performance in these areas would be addressed in the future through more frequent and higher quality inspection arrangements. The proposed regulations would retain these requirements.

2. Objectives of the proposed regulations

The objective of the proposed regulations is to reduce the risk of failure of electricity assets that could cause fires. Achieving this objective will reduce the incidence of bushfire ignition and the consequent costs to the community.

The specific objectives being pursued in order to achieve this outcome are:

- To ensure that an adequately specified Bushfire Management Plan is in place, thus providing transparency and accountability as to electricity companies' management of their above-ground assets; and
- To ensure that a timely and high-quality inspection process is maintained in place in relation to these assets and also private overhead electric lines.

More broadly, the regulations have been tailored to take into account the differential nature of the businesses and entities that are required to comply with general duties in the **Electricity Safety Act 1998** to minimise bushfire danger arising from their electricity assets and to submit BMPs. In relation to the major electricity companies (MECs), comprising licensed distribution and transmission companies, the regulations set out expectations and detail with respect to the content of BMPs, including key requirements relating to inspection of above-ground supply networks.

For an MEC that has a distribution area, the regulations also specify standards for inspection of private overhead electric lines (POELs) located in its distribution area. The requirements serve to ensure that distribution businesses apply consistent inspection standards to POELs across Victoria, which private landowners are not in a position to do.

In addition to MECs, another category of person having general duties and bushfire mitigation planning obligations are the so-called “specified operators”. Specified operators are a diverse group of entities for whom the distribution or transmission of electricity is incidental to their principal businesses. The regulations attempt to provide clear guidance as to what is required of specified operators in relation to their “at-risk” electric lines, i.e. lines above the ground in hazardous bushfire risk areas

3. Nature and extent of the problem

3.1. Bushfire ignition and electricity assets

3.1.1. Overview and historical context

Bushfires have a range of causes. They may occur naturally, usually due to lightning strikes. They may also have a range of man-made causes. Chief among these are loss of control of campfires and agricultural burns, arson and emission of sparks from the use of equipment or machinery. Failure of electricity assets can be considered to fall within the latter category. Electricity assets have historically not been significant contributors to the ignition of bushfires. However, there has been a particular focus on this ignition source following the Black Saturday bushfires in Victoria in 2009. This reflects the fact that the report of the Royal Commission into the Black Saturday fires of 2009 found that five of the eleven major fires occurring on that day were ignited as a result of the failure of electricity assets².

The Commission found that:

*"Although the proportion of fires that are caused by electricity infrastructure is low—possibly about 1.5 per cent of all ignitions in normal circumstances—on days of extreme fire danger the percentage of fires linked to electrical assets rises dramatically. Thus, electricity-caused fires are most likely to occur when the risk of a fire getting out of control and having deadly consequences is greatest."*³

That is, while only a relatively small proportion of bushfires have historically been ignited by electricity asset failures, the fact that these ignitions tend to occur when conditions are at their most extreme means that there is an elevated likelihood of a fire developing into a major fire, leading to large scale losses. This, in turn, means that the contribution of electricity asset failures to *total bushfire costs* is likely to be substantially greater than their contribution to ignitions.

The VBRC found⁴ that that major fatal fires had been ignited due to electricity asset failures in 1969, 1977 and 1983. Specifically:

- 9 of 16 major fires occurring on February 16, 1977 were caused by electricity assets;
- 4 of 8 fires occurring on Ash Wednesday 1983 were caused by electricity assets; and

² These were the fires —Kilmore East, Beechworth–Mudgegonga, Horsham, Coleraine and Pomborneit–Weerite. Of the remaining fires, four were found likely to have been deliberately lit, one was started accidentally, one was started by lightning and two had unknown origins. See: Victorian Bushfires Royal Commission (2010). Report Vol. 1: The fires and the Fire Related Deaths, p 226.

³ Ibid, p 12.

⁴ See: Victorian Bushfire Commission (2009). *Final Report*, Vol 2, Chapter 4.

- 5 of 11 major fires occurring on Black Saturday 2009 were caused by electricity assets.

Moreover, 70% of the 173 deaths due to the Black Saturday fires resulted from fires ignited by electricity asset failures⁵. The Commission also cited evidence to the inquiry into the 1977 fires from the then Chairman of the State Electricity Commission. Referring to the overall picture of electricity assets accounting for only a small proportion of total bushfire ignitions, this evidence stated:

" This overall picture is in sharp contrast to what happens on days of extreme conditions, such as January 8th 1969 or February 12th 1977. On such days, the incidence of SEC fires rises dramatically.

The alarming aspect of these figures is that they tend to occur in widely separated places at approximately the same time and at the time of day when conditions are such that the rate of spread of fire is likely to be at its peak"

Impact of ageing electricity infrastructure

The Commission also highlighted the fact that Victoria's electricity infrastructure is ageing and concluded that this ageing was a contributory cause of ignition in three of the five fires caused by electricity assets⁶. Failures of electricity assets may be caused by fatigue in one or more components, by incorrect installation of components during maintenance, or by combinations of these factors. For example, in relation to the Kilmore East fire, the Commission found:

"The fire started after the conductor between poles 38 and 39 failed and the live conductor came into contact with a cable stay supporting pole 38. This contact caused arcing that ignited vegetation near the base of pole 38. An electrical fault was recorded at 11:45.

The conductor failed as a result of fatigue on the conductor strands very close to where a helical termination was fitted to the conductor at pole 39. (A helical termination is a device used in electricity distribution; it is wound helically around the conductor and grips it, keeping tension in the line and holding the line off the ground.) The fatigue of the conductor strands was partly caused by the helical termination being incorrectly seated in a thimble, so that it was jammed between the thimble and a clevis device at pole 39, causing stress to the conductor..."⁷

In relation to the Horsham fire, the Commission found:

⁵ VBRC (2009) *Final Report*, various chapters. 119 fatalities occurred in the Kilmore East fire and 2 fatalities in the Beechworth-Mudgegonga fire, both of which fires were caused by electricity asset failures. Thus, 121 of 173 fatalities were caused by electricity asset failures.

⁶ In relation to the two remaining fires caused by electricity assets the primary causes were found to be a tree falling on a power line (Beechworth-Mudgegonga fire) and a clashing of conductors (Pomborneit-Weerite fire). These causes are clearly not related to the age of the electricity assets per se.

⁷ *ibid*, Vol. 1, p 75.

'the 7 February fire was started by a conductor that fell when the remaining two coach screws came loose as a result of wind-induced vibration enabling the pole cap to become detached. The failure of the pole cap to secure the conductor on pole 15 might have been avoided had there been a shorter inspection cycle: pole 15 had not been inspected for about four and a half years' (Vol 1., p.99).

In relation to the Coleraine fire:

'The fire started after the tie wire that held the conductor in place on the top of pole 3 broke, allowing the conductor to fall from the pole. The break probably occurred after Powercor, the operator of the line, had last inspected the line, in September 2004, in accordance with its asset inspection policy' (Vol 1, p.111).

The Commission cited research by a major distribution company relating to its own assets, which provides strong support for the view that the ageing of the Victorian electricity infrastructure is likely to increase substantially the risk of bushfire ignition due to asset failure in the absence of significant changes to current practices:

"SP AusNet provided to the Commission the results of a study of its conductor fleet, which noted, among other things, 'The primary issue facing SP AusNet is the increasing age profile and deteriorating performance (2% p.a.) of steel and copper conductor through failure ...' SP AusNet's conductors have a regulatory life of 60 years, and its conductor fleet has an average age of 41 to 45 years. Most of its steel and copper conductors are now more than 50 years old; they account for all conductors of above-average age in its fleet. The failure of steel and copper conductors is the primary type of conductor failure attributed to end-of-life characteristics.

*The report of SP AusNet's conductor study also noted that the great majority of conductor failures on the organisation's network involved high-voltage conductors and that this represented a 'considerable risk to the business from a public safety and bushfire perspective'. The report said, 'In the absence of planned conductor replacement programs, **failure rates may begin to increase at an exponential rate due to the increasing proportion of [the] conductor fleet approaching current failure age ranges'**"⁸ [emphasis added].*

Similarly, the VBRC cited a October 2004 report from Powercor, which showed that 16 per cent of the overhead distribution line assets in the Powercor network are between 35 and 44 years of age, 5 per

⁸ See: Victorian Bushfire Commission (2009). **Final Report**, Vol 2, Chapter 4.

cent between 45 and 54 years of age, 1 per cent between 55 and 64 years of age and 1 per cent between 65 and 74 years of age⁹.

International reports also indicate a high level of awareness of the issue of ageing electricity infrastructure and the associated expectation of a rapid increase in failure rates. For example:

"The components of electricity networks are ageing. It is expected that within a horizon of 15 years, the performance will deteriorate significantly, while the costs for operating the networks will increase enormously..."

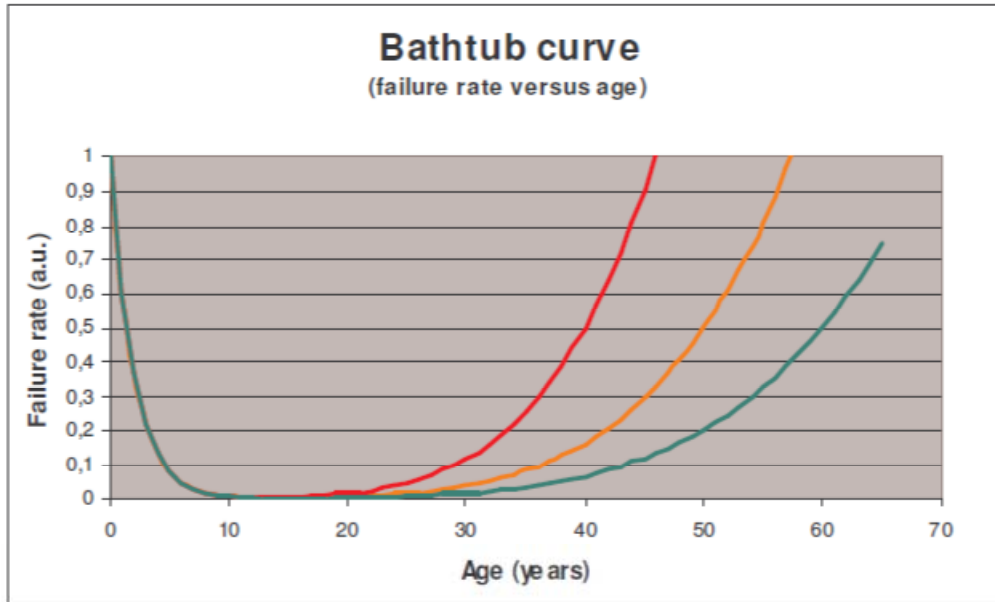
*Typically, after a certain period of operation, asset performance will deteriorate and the failure expectation will increase. However, the exact condition of most assets is unknown, and thus what their expected failure rates and remaining lifetimes are is also unknown. **Extensive condition assessments have to be made in order to fill this knowledge gap.**"¹⁰ [Emphasis added].*

The same source includes the following "bathtub curve" as a general representation of the relationship between asset age and failure rates within the electricity industry, with the different curves representing the impact of different maintenance regimes. This graph suggests that, even given a high quality maintenance regime, assets as old as those which form the main part of Victoria's electricity infrastructure are entering the period of rapidly increasing failure rates.

Graph 3.1: Relationship between age of electricity assets and expected failure rate

⁹ Exhibit 578 – SKM Powercor and Citipower Age Opex Report – *Impact of Ageing Assets on Operating Expenses*. Cited in Victorian Bushfire Commission (2009). *Final Report*, Vol 2, p 151.

¹⁰ Leonardo Energy (2007). *Electricity Briefing Paper*, p 1, p 4. Jongepier, AG. See: http://www.leonardo-energy.org/webfm_send/160



Source: Leonardo Energy (2007).

The Commission argued that, "as components of the distribution network age and approach the end of their engineering life, there will probably be an increase in the number of fires resulting from asset failures unless urgent preventive steps are taken". It therefore made a number of recommendations for medium to long-term action to reduce the risk of electricity assets causing future bushfires. These recommendations were:

- The progressive replacement of Single Wire Earth Return (SWER) and 22 kilovolt distribution feeders with other technologies (including aerial bundled cabling and underground cable) that provides substantially reduced bushfire risk (recommendation 27);
- To require distribution businesses to take steps to reduce the risk posed by hazard trees - i.e. those that may come into contact with electricity assets in foreseeable circumstances but are outside the clearance zone (recommendation 30); and
- That ESV require the fitment of spreaders to all lines with a history of clashing or a potential to do so and require the fitment of vibration dampers to all spans of over 300 metres between poles (recommendation 33).

The Commission also recommended that ESV's mandate to act to minimise the risks of bushfire ignition due to the failure of electricity assets be strengthened (recommendation 34).

At the same time, it was recognised that the necessarily long time-horizon over which many of these recommendations would need to be implemented meant that the identified risks of ignition due to electricity assets would remain significant for a number of years to come.

Alternative data on age-related failure rates

However, it should be recognised that the “bathtub curve” is not the only model that describes the relationship between asset age and failure rate. While this concept was previously regarded as widely applicable, empirical studies conducted in the airline industry, in particular, suggest that the actual relationship between asset age and failure rates can vary substantially from that predicted by the “bathtub curve”. Moubray (1992)¹¹ found that 68% of component types instead demonstrated a relatively high level of failures in their early life, followed by a random failure rate throughout the whole of their remaining life. That is, the increase in failure rates as assets near the end of their useful life was not observed in these cases. Moubray concluded the the “bathtub curve” represented one of the least common failure modes.

The importance of this research lies in the fact that it has given rise to the concept of “Reliability Centred Maintenance” (RCM). In contrast to the approach previously adopted in response to the “bathtub curve” model, in which assets were replaced at particular ages, regardless of whether they demonstrated signs of wear, the RCM approach is based on establishing the nature and frequency of the maintenance tasks that are required to ensure an optimum level of reliability is achieved at best cost. According to Robinson et al (2010)¹², the RCM process asks seven basic questions, as follows:

- What assets (significant items) are to be subject to the analysis process?
- What are the functions and associated performance criteria (accept/reject boundaries) of each asset in its operating context?
- In what manner does it cease to fulfil its listed functions (fault mode)?
- What failure mechanism causes each loss of function?
- What is the outcome and impact of each fault?
- What maintenance tasks can be applied to prevent each fault?
- What action should be taken if effective tasks cannot be identified?

The RCM approach was derived by the Maintenance Steering Group of the International Air Transport Association. It necessarily includes preventive maintenance and regular asset inspections within specified timeframes and aims to prevent an increasing failure rate as the relevant asset or system ages. The Victorian electricity distribution businesses have all adopted the RCM approach.

¹¹ Moubray, J. (1992). *Reliability Centred Maintenance*. Industrial Press, New York.

¹² Robinson, RM., Francis, G., Dean, M., Kanga, M., Robinson, J. & Stoks, F (2010) *Risk and Reliability: Engineering Due Diligence*. R2A Pty Ltd.

In sum, the size of the impact of future ageing of the electricity infrastructure on the fire risk that it poses is subject to significant uncertainty. However, there is clearly a possibility that this factor would tend to increase the contribution of electricity asset failure to bushfire ignition in the absence of policy initiatives.

3.1.2. Inspection regimes and bushfire risk due to electricity asset failure

Given the long-term implementation task for the above recommendations, the Commission also identified the need for action to be taken in the short term to reduce risk. These shorter-term recommendations focused on the inspection regimes that are fundamental to ensuring that specific electricity assets that have deteriorated and are at risk of failure are identified and replaced.

This focus reflected expert evidence to the Commission which indicated that the parameters of the inspection regimes adopted have very substantial impacts on the likelihood of bushfire ignition due to electricity asset failure. Hence, the effectiveness of the inspection regime is a crucial determinant in practice of the level of bushfire risk posed by electricity assets, while this dynamic is especially important in the context of an ageing asset base, due to the rapid increase in the probability of failure that occurs as assets near the end of their service life.

Box: Overview of electrical asset inspection tasks

Asset inspections are undertaken to identify faults in both the poles carrying electricity wires and in the pole-top hardware that directly supports the wires. In respect of wooden poles, inspection involves the clearance of any vegetation around the base of the pole, to allow access, then the inspector excavating approximately 500mm below ground level in order to drill a small "core" into the pole to enable assessment of the soundness of the wood within the pole. The girth of the pole is also measured and used as an indicator of soundness. The inspector will also apply a termiticide and/or fungicide if evidence of either termite infestation or a fungal infection is found. The drilled hole is then plugged and the excavated earth replaced. Finally, the inspector will "sound" the pole - i.e. strike the pole and listen for any resonant noises or "soft spots" that may indicate the presence of rot. [NB: No drilling of cores is undertaken in respect of concrete poles, since they are not susceptible to rot].

In respect of pole top hardware, a visual inspection of all cross-arms, insulators and other hardware, including the cables themselves, is undertaken. If this is carried out from ground level, it is usually completed using stabilised binoculars. If from the air, a high definition digital camera is deployed from a helicopter, which overflies the powerlines being inspected at low level.

Finally, the inspection process also involves taking photographs of the poles and defects found and the completion of record-keeping requirements.

As noted above, a range of evidence demonstrates that electricity assets can be expected to demonstrate rapidly increasing failure rates as they near the end of their service life, while much of the current asset base is approaching this point in its lifecycle. This likelihood of rapidly increasing failure rates clearly increases the importance of a timely and effective asset inspection regime as a major element in controlling the risk of bushfire ignition due to asset failures.

These observations alone would provide a significant body of evidence to suggest that asset inspection programs should be expanded and improved in the current context of rapidly ageing electricity infrastructure. However, the extent of the contribution of asset inspection issues to the broad problem of bushfire ignition risk due to asset failures is potentially increased further by virtue of the context being one in which asset inspection frequency has, in many cases, been significantly reduced from previous levels over the past 10 - 15 years.

The Commission heard that the former State Electricity Commission (SEC) had introduced a three-year inspection cycle following the 1977 bushfires. However, this cycle was progressively extended in the following years: in around the mid 1990s a five year cycle was adopted for assets not deemed a fire hazard, while the current practice of a five- year inspection cycle for timber poles and a ten-year cycle for concrete poles, including those in high bushfire risk areas, was adopted by the major distribution companies in the early 2000s.

Evidence was also presented to the Commission which specifically addressed the question of the relative effectiveness of different asset inspection frequencies in preventing the in-service asset failures that give rise to bushfire ignition risk. The Commission cited a 1997 study of the Powercor network which found that a reduction in the inspection interval from five years to three years would be expected to result in a 70 per cent reduction in in-service failures. The same study found that:

"...a substantial improvement in the effectiveness of asset inspection significantly reduces the risk of in-service asset failure. Powercor's analysis shows that, if the improvements in effectiveness foreshadowed in 1997 had been made without extending the inspection cycle, the projected number of in-service failures each year would have reduced from 500 to 84."¹³

Thus, a study commissioned by a major electricity company concludes that both the length of the asset inspection cycle and the effectiveness of the inspections undertaken are critical determinants in practice of the extent of the risk of bushfire ignition due to electricity asset failures. The context is one in which the regulations did not, until the passage of the Interim regulations in 2010, contain any specific requirements in relation to the training of inspectors. In the case of major electricity distribution companies, inspection services have frequently been supplied under contract by external service providers. The distribution companies have required inspectors operating under these contracts to have successfully completed a training course which is based on that previously developed by the SECV.

¹³ Victorian Bushfire Royal Commission (2010). **Final Report**. Vol. 2, Ch 4., p 160.

However, evidence presented to the Commission has highlighted faults with current training arrangements, as well as those relating to the auditing of the performance of inspectors. In general terms it was found that, whereas asset inspections had previously been undertaken by linesmen, who had undertaken substantial training in a wide range of problems found throughout the system in the context of an extended apprenticeship, inspection activity was now largely undertaken by inspectors with very limited and specific training. In the case of one third party provider of inspection services, the initial training provided consisted of three days of classroom training, a competency test and a period of supervised field work.

Moreover, evidence was presented that inspectors had on occasion, received training provided by organisations not accredited as Registered Training Organisations under the Australian Vocational Education and Training (VET) framework, despite this being a contractual requirement of major electricity companies.¹⁴

Reviewing this evidence, the Commission argued:

"Improving the efficacy of inspection regimes is crucial to mitigating the bushfire risk created by the failure of electricity assets. Whether network components are repaired or replaced before they fail or are at risk of failing is determined in almost all cases on the basis of inspection results, and there is heavy reliance on cyclical inspections¹⁵"

The Commission found that:

"... both expert opinion and the network operators' analyses support a finding that shortening the inspection cycle would appreciably reduce the risk of assets failing in service and consequentially reduce the risk of bushfires starting as a result of failed assets".¹⁶

Consistent with this view, it recommended that both the frequency and the effectiveness of asset inspections should be significantly improved. Specifically, it recommended:

The State (through Energy Safe Victoria) require distribution businesses to change their asset inspection standards and procedures to require that all SWER lines and all 22-kilovolt feeders in areas of high bushfire risk are inspected at least every three years. (Recommendation 28)

and

The State (through Energy Safe Victoria) require distribution businesses to review and modify their current practices, standards and procedures for the training and auditing of asset inspectors to ensure

¹⁴ VBRC (2010), op. cit, pp 162 - 165.

¹⁵ ibid, Vol. 2, p 159.

¹⁶ ibid, Vol. 2, p 160.

that registered training organisations provide adequate theoretical and practical training for asset inspectors. (Recommendation 29).

The Current Regulatory Context

As noted above, the VBRC recommendations regarding minimum inspection frequencies and the establishment of specific qualifications requirements for inspectors were implemented initially in 2010, via interim regulations, and confirmed in 2011, following the preparation of a Regulatory Impact Statement and the subsequent passage of amendments to the principal regulations. Given that the VBRC characterised its recommendations in relation to the inspection regime as being short-term in nature, the question may arise as to whether these requirements, which will have been in place for approximately three years at the time of the scheduled sunseting of the current regulations, should be maintained into the future.

However, judgements as to what constitutes the short and long term must be made in the context of the asset replacement cycle. The time horizon for the full implementation of recommendations 27, 30 and 33 of the VBRC Report (as set out above) is expected to extend well into the life of the proposed regulations. This being the case, the concerns regarding inspections raised by the VBRC continue to be relevant. This, in turn, implies that the identified rationale for prescriptive regulation of the inspection regime remains relevant.

3.1.3. The role of Bushfire Management Plans

The Electricity Safety Act 1998 (the Act) establishes a process based regulatory regime, which seeks to ensure that the full range of risks arising from the use of electricity are managed in a systematic way. The risk of bushfire ignition due to electricity asset failure is clearly only one of these categories of risk, albeit a very significant one.

In relation to Major Electricity Companies (i.e. owners of electricity supply networks) the fundamental elements of this framework are as follows:

General duties

Part 10 of the Act establishes general duties that apply to MECs. Section 98 states that

A major electricity company must design, construct, operate, maintain and decommission its supply network to minimise as far as practicable—

- (a) the hazards and risks to the safety of any person arising from the supply network;*
- and*

(b) the hazards and risks of damage to the property of any person arising from the supply network; and

(c) the bushfire danger arising from the supply network.

Electricity Safety Management Schemes (ESMS)

Part 10 also requires MECs to submit to ESV an ESMS which sets out the safety management system that they have in place to acquit the above general duties. ESV is required to consider and accept or reject an ESMS and may require the ESMS to be validated by an independent party prior to commencing this consideration. ESMS are required to be revised at five yearly intervals and are also required to be revised in certain specific circumstances, including when there are significant changes to the management of the system or to the state of technical knowledge that are of relevance to the ESMS.

As a result of legislative amendments made in 2010, the Bushfire Management Plan (BMP) now formally forms part of the ESMS.

Bushfire Management Plan

Part 10 of the Act, dealing with ESMS, states that an ESMS must include a plan for the mitigation of bushfire danger in relation to the major electricity company's supply network. Section 113A of the Act sets out a number of specific requirements in relation to BMP, including:

- That it must be in a form approved by ESV;
- That a BMP must be submitted annually to ESV for acceptance; and
- That an accepted BMP be available for public inspection.

In addition, Section 113A states that the BMP must "include the prescribed particulars". These prescribed particulars are set out in the current regulations.

Part 8 Requirements in Relation to Bushfire Mitigation

Part 8 of the Act also sets out requirements in relation to bushfire mitigation that affect certain operators of "at risk electric lines" - in effect, above ground poles, wires and associated infrastructure that are located in Hazardous Bushfire Risk Areas (HBRA). Part 8 applies primarily to Specified Operators, who are operators of "at risk electric lines" other than MECs.

Part 8 establishes largely equivalent arrangements to those discussed above in respect of:

- The establishment of general duties for Specified Operators to minimise bushfire risk in connection with their at risk electrical lines; and
- The requirement to develop and submit BMP annually and to comply with an accepted BMP.

Box: Bushfire Risk Classification

A “*hazardous bushfire risk area*” is defined in Section 3 of the ESA as:

An area to which a *fire control authority* has assigned a *fire hazard rating* of “high”, under Section 80 of the ESA; or
An area that is not an urban area, other than an area than an area a *fire control authority* has assigned a *fire hazard rating* of “low” under section 80.

A *fire control authority* is defined in ESA section 3 as being either the MFB, CFA or Secretary of the Department of Natural Resources and Environment (now, in effect, the Department of Sustainability and Environment (DSE)).

Thus, all non-urban land is considered to an HBRA by default. Non-urban land will only be considered to be an LBRA if its *fire hazard rating* is explicitly assigned a “low” classification by a *fire control authority*. Conversely, urban land is, by default, considered to be an LBRA and will only be considered to be an HBRA if its *fire hazard rating* is explicitly assigned a “high” classification by a *fire control authority*. The CFA explicitly assesses the bushfire risk level of all areas for which it is responsible on a four-yearly cycle. Thus, all land within the CFA's area of responsibility is subject to a specific bushfire risk classification, rather than the default categorisation set out in the Act.

Summary of the legislative provisions relating to BMP

As the above demonstrates, the Act both creates general duties for MECs and SOs to manage their electricity assets in such a way as to minimise bushfire risk and specific requirements to prepare plans (ESMS incorporating BMP, in the case of MECs and BMP in the case of specified operators) that demonstrate how they will comply with those general duties.

Within this context, the BMP-related requirements of the current regulations, as well as the proposed regulations, essentially set out certain requirements as to how this demonstration of the means of compliance is to be effected.

3.2. The costs of bushfires

3.2.1. Incidence of bushfires

The Report of the Victorian Bushfires Royal Commission (Vol 1, Appendix C) summarised the incidence of major bushfires in Victoria between 1851 and 2007, as recorded in the Emergency Management Australia Disasters Database. Table 3.1 provides major statistics taken from that summary. It shows that Victoria has historically suffered an average of one major bushfire every three years and that an

average of 2.5 people per year are killed by bushfire. More than 77 buildings are lost per year on average, while more than 83,000ha of land is burned.

Table 3.1: Incidence and consequences of major fires in Victoria 1851 - 2007 - summary statistics¹⁷

Statistic	Total (1851 - 2007)	Annual average
Number of fires	52	0.33
Total fatalities	391	2.5
Buildings lost	More than 12,000	More than 77
Area burnt	More than 13 million ha	More than 83,000 ha

These estimates do not include the Black Saturday fires. Adding those fires clearly increases these totals and averages significantly. For example, a total of 391 people had been killed by major bushfires in the 156 years prior to Black Saturday. Given that a further 171 people were killed on Black Saturday, the total over Victoria's history rises to 562 and the annual average to 3.6. Similarly, adding the 11 major fires occurring on Black Saturday to the 52 fires identified as having occurred in Victoria since 1851 raises the average number of fires per annum to 0.41, equivalent to one major fire every 2.5 years.

3.2.2. The Black Saturday bushfires

The costs of bushfires were also documented extensively by the Royal Commission. These costs include loss of life, serious injuries and substantial property damage. They also include the cost of fire suppression efforts and the costs of providing emergency assistance. The Commission's estimate of the total cost of the Black Saturday fires was approximately \$4.4 billion. Table 3.2, below, is reproduced from the Royal Commission report and provides a breakdown of this figure. As the Commission inquired into 15 fires, this suggests that the average cost of each fire was of the order of \$293.3 million.

Even these estimates arguably understate the true costs involved since, while estimates of the statistical value of the lives lost were included, the Commission did not seek to estimate injury costs. A subsequent analysis found that "*Most victims of the Victorian bushfires either died or survived with minor injuries*"¹⁸. However, that statement does not account for the impact of grief and psychological trauma, nor could that be costed in dollar terms.

Fires ignited by electricity asset failures were responsible for a very large proportion of these costs. For example, 70% of the 173 deaths due to the fires resulted from fires ignited by electricity asset failures.

¹⁷ Note that estimates are not available for all of the reported types of loss for all of the bushfires reported by the Commission. Hence, the totals and averages reported in this table necessarily constitute under-estimates.

¹⁸ Peter A Cameron, Biswadev Mitra, Mark Fitzgerald, Carlos D Scheinkestel, Andrew Stripp, Chris Batey, Louise Niggemeyer, Melinda Truesdale, Paul Holman, Rishi Mehra, Jason Wasiak and Heather Cleland (2009). *Black Saturday: the immediate impact of the February 2009 bushfires in Victoria, Australia*. Medical Journal of Australia, Vol. 191 (1): 11-16

Evidence to the Royal Commission also indicated that major fatal fires had been ignited due to electricity asset failures in 1969, 1977 and 1983¹⁹.

Table 3.2: Cost of the Black Saturday Bushfires

Table A.1 Estimated major economic costs of Victoria's January–February 2009 bushfires: a summary

Item	Cost (\$ million)	Source
////////////////////////////////////		
RESPONSE COSTS		
Victorian Government—supplementary funding for fighting 2009 fires	593	Victorian Government Green Paper on the fire services levy
Value of CFA and other volunteer time plus additional costs incurred by the MFB, ADF, Victoria Police, SES, State Coroner's Office, NEO and DSE as a result of the fires	Not estimated	
DAMAGE COSTS		
General insurance claims paid	1,200	Insurance Council of Australia
Loss and damage to public infrastructure	77	Victorian Managed Insurance Agency
VBRRA—establishment costs, expenditure to date and projected further expenditure	1,081	VBRRA: <i>Rebuilding Together</i> . Includes VBRRA disbursements and planned disbursements from the Victorian Bushfire Appeal Fund and from other donors
Valuation of lives lost	645	Commission estimate
Loss of livestock and agricultural output	Not estimated	
Timber—value of destroyed timber, replanting costs for private plantations and salvage costs	658	Victorian Association of Forest Industries submission quoting VicForests
Asset damage and other costs incurred by Telstra and Melbourne Water. (Long-term impact on water supply was not estimated.)	25	Information from Telstra; Melbourne Water annual report for 2008–09
Cost of 2009 Victorian Bushfires Royal Commission, including costs incurred by state agencies in responding to the Commission	90	Victoria's 2009–10 Budget; Victorian Managed Insurance Agency
Total	4,369	
////////////////////////////////////		

Source: Victorian Bushfires Royal Commission Report, Vol. 1, p 345.

3.2.3. Expected cost of bushfires

As noted above, the average cost of each fire that broke out on Black Saturday was almost \$300 million. Similarly, the bushfires occurring in Canberra in 2003 were estimated to have a cost of \$300 million, while the Ash Wednesday fires of 1983 were estimated to cost around \$400 million.

¹⁹ Evidence of Tim Tobin SC. See: **70% of deaths from power line failure: lawyer**. The Age, 10 September 2009.

Research conducted by the Bureau of Transport and Regional Economics (BTRE) in 2001²⁰ provides a broader database on the costs of bushfires. This research, which considered the costs associated with a wide range of natural disasters occurring across Australia over a period of more than three decades (1967 - 1999) found that:

The costs (\$2.5 billion) associated with bushfires represent a relatively small proportion (7.1 per cent) of the total disaster costs. However, as discussed later in this chapter, bushfires are the most hazardous type of disaster in terms of deaths and injuries.

However, bushfire was found to be the fourth most frequent natural disaster costing more than \$10 million.

The above estimate of the cost of bushfire in Australia over this period can be considered to be an under-estimate of the true costs of bushfires for two main reasons. First, BTRE notes that it is not clear that the database it uses to generate these estimates includes the cost of forestry losses, while these have constituted a major part of the value of the losses in a number of recent fires including those of Ash Wednesday (1983) and those in Canberra (2003). Second, the BTRE found that \$1.4 billion of the \$2.5 billion cost comprised the value of fatalities and injuries. However, the BTRE's Value of a Statistical Life (VSL) figure was only \$1.3 million, while its figure for the cost of a serious injury was only \$317,000. By contrast, currently used values for VSL, based on the Willingness to Pay (WTP) methodology are between \$3.5 million and \$6.0 million, while the valuation of a serious injury is typically 0.2 times these figures, or \$0.7 - 1.2 million²¹.

Substituting these figures suggests that the value of deaths and injuries over the period was in the range \$3.8 - 6.5 billion approximately (i.e. $1.4 \times (3.5/1.3)$ and $1.4 \times (6.0/1.3)$ respectively). Moreover, the remaining \$1.1 billion in costs (i.e. those not related to fatalities and injuries) is expressed in 1998 dollar terms in the BTRE paper. The current dollar equivalent is \$1.6 billion²².

The above implies that the best estimate of the current dollar costs of bushfires in Australia in the period studied by the BTRE is that it lies in the range \$5.4 - 8.1 billion. This is equal to an average of \$169 - 253 million per annum. As noted above, this adjusted figure still potentially excludes the value of property losses. The BTRE paper identified 22 bushfires over the relevant period that had caused damage in excess of \$10 million in value. Given the above total cost (in 2011 dollar terms) of these fires

²⁰ Bureau of Transport and Regional Economics (2001). *Economic Costs of Natural Disasters in Australia*. Report No. 103.

²¹ The Office of Best Practice Regulation's *Best Practice Regulation Guidance Note* on VSL argues that an appropriate base case figure for VSL is \$3.5 million. This figure is based on research by Abelson (2007). An alternative figure of \$6.0 million has also been calculated by Access Economics on behalf of the Office of the Australian Safety and Compensation Council. Both of these figures are based on meta-analyses of relevant research, using Willingness to Pay (WTP) methodologies. See: Abelson, P. (2007). Establishing a Monetary Value for Lives Saved: Issues and Controversies. Paper prepared for the Office of Best Practice Regulation. See also: Access Economics (2008) *The Health of Nations: The Value of a Statistical Life*. Report prepared for the Office of the Australian Safety and Compensation Council. For a discussion of the valuation of a serious injury in WTP terms and the rationale for so doing, see: Soby, BA., Ball, DJ. & Ives, DP. (1993). *Safety Investment and the Value of Life and Injury*. Risk Analysis, Vol. 13, No. 3, June 1993, pp 365-370.

²² CPI All Groups Australia December 2010 = 174.0, December 1998 = 121.9. $174.0/121.9 = 1.427$. $\$1.1\text{bn} \times 1.427 = \1.57bn .

of \$5.4 - \$8.1 billion, this implies an average cost per fire of \$245.5 - 368.2 million. This is consistent with the figures cited above in respect of the Black Saturday fires, the Ash Wednesday fires and the Canberra fires of 2003.

The BTRE study estimated that the average annual cost to Victoria of bushfires in the years between 1967 and 1999 was \$32.4 million. However, as demonstrated above, adjusting the national figures presented by BTRE for this period to account for currently accepted VSL values and update the figures for property damage to 2011 dollar values raises the BRTE estimates by a factor of 2.16 to 3.24. Applying these ratios to the estimated costs for Victoria over the period gives likely average annual costs of bushfires in Victoria of \$70.0 - 105.0 million.

Moreover, recent research suggesting that the incidence of extreme weather conditions - including those that are conducive to bushfire - is increasing also suggests that the future cost of bushfires is likely to be substantially greater than the historical cost. For example, the UN Inter-Governmental Panel on Climate Change reported in 2007 with "high confidence" that Australia and New Zealand were already experiencing impacts from recent climate change, stating "*Heat waves and fires are almost certain to increase in intensity and frequency*"²³. The New South Wales Government, in a 2010 review of the expected impacts of climate change on natural hazards profiles, similarly concluded that:

*"The frequency of very high or extreme fire-risk days is projected to increase in the Riverina Murray and across New South Wales. Increases in temperature, evaporation and high-risk fire days are likely to influence fire frequency and intensity across the region, and the fire season is likely to be extended"*²⁴

3.2.4. Cost of fires due to electricity assets

As suggested above, there is considerable uncertainty as to the overall contribution of electricity assets to the costs imposed by bushfires. While the Royal Commission found that only around 1.5% of all bushfire ignitions are due to this cause, it noted that such ignitions were most likely to occur in extreme conditions in which bushfires are most likely to have disastrous consequences. This observation has two important implications. First, the contribution of electricity assets to the overall cost of bushfires is inevitably far higher than this 1.5% of ignitions figure would imply.

Second, the contribution of electricity assets to the cost of major bushfires is significantly greater than their contribution to the costs of all bushfires. The VBRC found²⁵ that around 70% of the Black Saturday fatalities were due to fires caused by electricity assets, while around half of the major fatal bushfires of 1969, 1977 and 1983 had been ignited due to electricity asset failures. Specifically:

²³ Intergovernmental Panel on Climate Change (2007). **Fourth Assessment Report**. Cited at: <http://knowledge.allianz.com/health/science/?434/australia-bushfires-changing-climate-fans-the-flames>

²⁴ Department Of Environment, Climate Change And Water (2010) **IMPACTS OF CLIMATE CHANGE ON NATURAL HAZARDS PROFILE RIVERINA MURRAY REGION**, p 8. NSW Government.

²⁵ See: Victorian Bushfire Commission (2009). **Final Report**, Vol 2, Chapter 4.

- 9 of 16 major fires occurring on February 16, 1977 were caused by electricity assets;
- 4 of 8 fires occurring on Ash Wednesday 1983 were caused by electricity assets; and
- 5 of 11 major fires occurring on Black Saturday 2009 were caused by electricity assets.

Moreover, the Commission argued that the ageing nature of Victoria's electricity assets meant that their contribution to fire ignition, and hence bushfire costs, would increase in the future in the absence of policy action. This factor must also be weighed in determining the base case against which the potential benefits of the proposed regulations are to be weighed.

It must also be noted that the above estimates of the expected annual cost of bushfires relates *solely* to major bushfires (defined as those causing losses valued in exceed of \$10 million, using the conservative BTRE methodology). Thus, the likely proportion of these costs attributable to failures in electricity assets is, as noted above, higher than that applicable to bushfires as a whole.

Given the combination of the above factors, particularly the observation that 50% of major fires occurring during the last three catastrophic bushfire outbreaks in Victoria (those of 1977, 1983 and 2009) were caused by electricity assets, an indicative estimate of the proportion of major bushfire costs likely to be attributable to electricity asset failures in the future, in the absence of specific policy action, of around 50% is considered reasonable.

As noted above, the total annual costs of major bushfires in Victoria are estimated to be in the range \$70 - 105 million at present. If electricity asset failures are responsible for 50% of this total, the cost of fires caused by electricity assets could be of the order of \$35.0 - \$52.5 million per annum on average. In addition, there is the widely discussed probability that changing weather patterns will increase the incidence and severity of bushfires²⁶. To the extent that this occurs, the expected future cost of bushfires will increase, leading to a proportionate increase in the expected cost of bushfires due to failures in electricity assets

3.3. Market failure issues

The electricity assets in question are privately owned. Asset owners have significant incentives to manage their assets in ways that reduce the likelihood of their contributing to bushfire ignition. These incentives derive in part from the fact that bushfires may cause significant damage to these assets, implying substantial costs to asset owners. In addition, where fires are caused by these assets, those who incur losses as a consequence will potentially take legal action to recover those losses from the electricity asset owners. Indeed, actions of this kind are currently on foot following the Black Saturday fires. Thirdly, electricity asset owners may suffer due to negative community perceptions if it is believed that the ignition of fires resulted from a failure to maintain those assets adequately.

²⁶ See, for example, the references cited in Section 3.2.3, above.

The presence of these incentives toward appropriate asset management/maintenance practices means that it is necessary to identify specific rationales for regulatory intervention to affect practice in this area. Two basic rationales can be identified: market failures and the need to maintain community confidence. These are considered in turn, below.

Market failures of two types can be identified: externalities and differential discount rate issues.

3.3.1. Externalities

In practice, it is unlikely that legal action will be successful in forcing asset owners to bear all of the costs associated with fires caused by electricity assets. That is, it is unlikely that those who suffer property loss, are injured or have relatives who are killed by fires would be successful in being fully compensated for their losses via the legal system. Reasons for this inability to obtain full restitution would include the transactions costs of taking legal action, disincentives to taking action due to uncertainty as to the outcome, and uncertainties as to the cause of many fires leading to limited awards being made.

To the extent that parties suffering losses are unable to retrieve those losses from asset owners, those asset owners do not bear the full cost of the losses caused by those assets. This, in turn, will mean that they will have sub-optimal incentives to invest in inspection and maintenance activity to reduce the risks of fires being caused by electricity asset failures.

Recognition of these issues has led the Department of Primary Industries to propose an "F-factor Scheme" to improve the market incentives for electricity businesses to reduce the contribution of their electricity assets to bushfire starts. In explaining the perceived need for such an approach, the Department has noted:

"Following the 2009 bushfires, concerns were raised that the existing incentive schemes do not adequately target the arrangements that electricity distribution businesses have in place to mitigate the number of fires caused by electrical assets. In addition, concerns have been raised that the current service incentive scheme provides greater incentives for electricity distributors to improve services in "high density areas" which are less exposed to bushfire risk than "low density areas".

To address this concern, the Department of Primary Industries developed the concept of a financial incentive scheme (also referred to as an f-factor scheme) to encourage improvements in the management of electricity assets to reduce the number of fires started by electricity assets...

Through the f-factor scheme, the electricity distributors have a financial incentive to reduce the number of fires started by electrical assets where the costs to do so are less than the benefit received through the financial incentive scheme.

It is proposed that the f-factor scheme will operate in a similar way to the current service incentive scheme. It will balance the service/price trade-off by linking annual changes in the electricity distributors' regulated revenue to the number of fires started by its electricity distribution assets each year. However, while the service incentive scheme is based on averages and is therefore skewed towards "high density areas", the f-factor scheme will be based on absolute numbers and is therefore skewed towards areas where the likelihood of fires starting is higher."²⁷

The issue remains a contested one, with electricity distributors arguing that efficient incentives to minimise the incidence of bushfire starts due to electricity asset failures already exist. For example, Jemena has argued in its submission in response to the DPI Consultation Paper:

"JEN considers that a distribution company's exposure to financial risk (e.g. potentially huge increases in insurance premiums and repair costs and public outrage resulting from a bushfire such as "Black Saturday" are itself sufficient drivers for it to manage its electricity assets to minimise the number of fire starts".

The extent to which market failure exists due to the incentives to minimise ignitions due to electricity assets being inefficiently small will necessarily be considered more closely as part of the above policy process to determine whether to introduce the proposed F-factor scheme and, if so, in what form. However, as the above indicates, it is the current view of the Department of Primary Industries that such market failures do exist and require changes in the incentives in order to improve economic efficiency. The substantial program of action to reduce electricity asset caused bushfire ignition recommended by the Royal Commission also clearly indicates that the Commission took the view that adequate (i.e. economically efficient) market incentives on electricity companies did not exist.

3.3.2. Differential discount rates

It is widely argued to be a feature of the current operation of investment markets, including arrangements for incentive based remuneration, that company managers face strong incentives to maximise short-term profits, even at the expense of higher long-term rates of return. Even in the absence of these specific incentives, it is likely that the effective discount rate applied by company management, which is based on the cost of capital, will be higher than the implicit social discount rate - the latter concept being based on the social "rate of time preference"²⁸. This reflects the fact that the latter concept is not based on the cost of capital *per se*.

²⁷ Department of Primary Industries (2011). *Establishing a financial incentive scheme to reduce fire starts from electricity distribution assets - the F-Factor: Consultation Paper*.

²⁸ The rate of time preference pertains to how large a premium a consumer places on enjoyment nearer in time over more remote enjoyment. The higher the time preference, the higher the discount placed on returns receivable or costs payable in the future.. The social rate of time preference is defined as the rate of time preference of society as a whole. In general, the

If the discount rate applied by company management in determining expenditure decisions is higher than the social discount rate they will have insufficient incentive (*vis-a-vis* the social optimum) to spend money in the short term to avert longer term harms. This may constitute another contributing factor toward inadequate maintenance expenditures being undertaken voluntarily.

3.3.3. Maintaining community confidence

As discussed below, while electricity assets are responsible for the ignition of only a small proportion of the overall number of bushfires, they are responsible for a much larger proportion of major bushfires occasioning large scale damage and loss of life. As documented in the report of the Victorian Bushfires Royal Commission, electricity assets have been responsible for the ignition of a large proportion of the fires occurring on each of the last four major bushfire events in Victoria; those of 1969, 1977, 1983 and 2009. Moreover, fires ignited by electricity assets caused a majority of the fatalities recorded on Black Saturday.

ESV believes there is a high level of awareness of these facts in the general community, given the wide publicity given to the work of the VBRC. Moreover, the fact that a class action against a MEC has been commenced, suggests that there is a level of dissatisfaction with the performance of these organisations in managing bushfire risks. In this context there is a need to act to ensure that community confidence in the safety of electricity infrastructure is re-established and that people can be confident that these assets are being appropriately managed.

3.3.4. Recent context

An additional perspective on this issue is provided by the legal consequences of the Black Saturday bushfires for the electricity distribution businesses. At least five class actions have been brought against the distribution businesses since the 2009 fires. Two of these have now been settled, with the action against Powercor in respect of the Horsham fire resulting in a settlement reported to be valued at up to \$40 million, while that against SPI and related parties is reported to be valued at up to \$32.85 million. Thus, two distribution businesses have already agreed to bear liabilities of up to \$72.85 million in respect of only two of the Black Saturday fires. In addition:

- A class action in respect of the Kilmore East/Kinglake fire was launched in February 2012 by Maurice Blackburn lawyers;
- A class action in respect of the Murrindindi/Marysville fire was also launched by the same lawyers; and
- A class action in respect of the smaller Weerite/Pomborneit fire is also expected to go to trial.

social rate of time preference is regarded as relatively low, implying that society as a whole discounts long-term projects less than individuals do.

It is clearly plausible that the total liability borne by electricity distribution companies following the Black Saturday fires will exceed \$100 million when all actions are settled. This amount will, however, necessarily fall well short of the total costs involved. According to the VBRC, inadequate inspection practices had a substantial role in leading to the ignition of the fires that led to these losses.

4. Summary of the proposed regulations

The following provides a general overview of the content of the proposed regulations. A copy of the proposed regulations is also attached as Appendix 1.

Prescribed particulars for Bushfire Management Plans

Parts 8 and 10 of the Electricity Safety Act 1998 provide that operators of "at risk" electric lines and supply networks, respectively, must prepare and submit to ESV for acceptance a Bushfire Mitigation Plan (BMP). As noted above, both the existing and the proposed regulations set out details of the required contents of these BMP. The proposed regulations set out similar, but separate, requirements in respect of BMP for MECs and specified operators (see Regulations 6 and 7). In general terms, the required content of the BMP includes:

- Contact details for the responsible person in relation to the plan;
- The bushfire mitigation policy or the organisation;
- The objectives of the plan;
- A map or other description of the area to which the plan applies;
- The preventive strategies and programs to be adopted to minimise the risk of fire ignition;
- A plan which ensures that above-ground electric lines and supply networks in HBRAs are inspected at intervals of no more than 37 months²⁹;
- Details of processes and procedures to ensure that only qualified persons inspect electrical assets;
- The operation and maintenance plans for electric lines and networks:
 - in the event of a fire;
 - on total fire ban days;
 - during a fire danger period; and
 - on a Code Red day.
- the "investigations, analysis and methodology" to be adopted to prevent fire ignition;
- details of monitoring and auditing arrangements in relation to the plan;
- details of the organisation's policies on provision of assistance to fire authorities; and
- details of arrangements to ensure public awareness of the obligations of owners in relation to private overhead electrical lines (POELs) and of the responsibilities of MECs in this regard.

²⁹ the proposed regulations exclude terminal stations and zone substations from the 37-month inspection requirement.

Quality and frequency of inspections

Among the required content of the BMP, established in proposed regulations 6 and 7, is detail of a plan to ensure that inspections of above-ground assets in HBRA occur with a minimum frequency of once in 37 months. A new provision would require the inspection of above-ground assets in LBRA to occur with a minimum frequency of once in 61 months. The requirement for MECs to ensure that POELs are inspected at intervals not exceeding 37 months is separately established in regulation 9.

Proposed regulations 6 and 7 also require that only inspectors who are competent and hold the qualifications approved by ESV for this purpose carry out inspections.

Proposed regulation 10 establishes standards for inspection by distribution businesses for private overhead electric lines.

5. Expected costs of the proposed regulations

The following discussion of the expected costs of the proposed regulations is presented in three parts. The first deals with the costs of preparing the BMP document, including validation as required and submission and acceptance by ESV. The second relates to the costs associated with the specific requirements adopted in 2010 in relation to the frequency of inspection of electricity assets and the qualifications required to be held by inspectors. The third summarises the costs incurred by ESV in relation to the administration and enforcement of these regulatory requirements.

5.1. Preparation of Bushfire Management Plans

5.1.1. Data sources and approaches

As part of the process of reviewing and revising current regulatory provisions in relation to bushfire mitigation, including both the remaking of the current bushfire mitigation regulations and the development of amendments to the Electricity Safety Act, a questionnaire was developed by ESV and sent to a range of stakeholders, including all MECs. This questionnaire sought, *inter alia*, information on the costs incurred by MECs in developing BMP and in reviewing and revising the BMP as required.

Responses were received from all five MEC. The data included in these responses has been used as the basis for the following cost estimates. Respondents were asked to identify separately the internal staff time required to complete the document and the cost of external consultancy and other resources, where these were used in BMP preparation. However, it should be noted that the questionnaire did not ask respondents to provide discrete costings for different elements of the BMP preparation task.

5.1.2. Cost of BMP preparation - Major Electricity Companies

Initial plan preparation

Table 5.1., below, provides estimates of the average resource inputs required to produce BMP, including the initial drafting of the plan and submission to ESV, as well as the completion of any revisions required in order to have the plan accepted by ESV, as required under the Act. These estimates are based on responses from all five distribution businesses to the data request made as part of the current legislative reform project. The estimates received were found to be broadly consistent, with four of the five responses being within approximately 100% of the lowest estimated cost. This degree of consistency suggests that the respondents took similar approaches to interpreting the questions contained in the data response and that the resulting estimates are comparable in nature.

Table 5.1: Costs of BMP development - Electricity Distribution Businesses

	Internal Direct labour (hours)	Internal management costs (hours)	Consultants	Other ³⁰
Initial plan preparation	101.5	17.8	\$ 1,300	\$ 570
Amendments	39.4	9.45	\$ 330	\$ 890

Source: Questionnaire responses from DBs, received September/October 2012

All distribution businesses have been required to have BMP in place for almost a decade. However, BMP have, since 2010, formally constituted part of the ESMS, which is required to be reviewed and re-submitted at five-yearly intervals. In this context, the data listed under the heading of "initial plan preparation" can be understood as relating to the process of developing a substantially revised BMP as part of re-submitting a new ESMS. Thus, this cost would be incurred at five yearly intervals. In each of the four years between the re-submission of ESMS, the costs incurred in respect of ESMS are those listed in the "amendments" row of table 5.1.

The estimates set out in table 5.1 are partly denominated in terms of person hours input to BMP-preparation and partly denominated in dollar terms. Person-hours based estimates are adopted where internal staff resources have been used to complete BMP development tasks, while dollar estimates are provided in respect of external expenditures (i.e. on consultants and ancillary services). This approach is consistent with the requirements of the VGR and is intended, in part, to ensure that consistent approaches are taken to the treatment of non-wage labour costs and corporate overheads. Thus, in converting the above hourly input estimates into dollar terms, the following method has been followed:

- Direct labour inputs have been costed at the average adult ordinary time hourly wage rate³¹;
- Internal management inputs have been costed at twice the average hourly wage rate;
- The resulting direct wage costs have been multiplied by 1.75, as recommended by the VCEC, to account for non-wage labour costs and corporate overheads.

Table 5.2. summarises the result of the application of this method to the above hourly estimates of the labour inputs required to develop and amend BMP. The dollar estimates of external contractor costs are unchanged from Table 5.1.

Table 5.2: Dollar cost estimates - BMP Preparation and Amendment by Distribution Businesses

³⁰ Expenditures cited under "other" included costs of printing and binding, as well as expenses connected with the submission of plans to ESV.

³¹ See ABS Cat. 6302.0. A rate of \$34.89 per hour has been used, based on the May 2012 trend estimate of average adult full-time weekly ordinary time earnings of \$1,326.00, divided by a standard 38 hour working week.

	Internal Direct labour	Internal Management costs	Consultants	Other external costs	Total cost
Initial plan preparation	\$6,197	\$2,174	\$1,300	\$570	\$10,241
Amendments to existing BMP	\$2,406	\$1,154	\$330	\$890	\$4,780

Table 5.2 shows that the total cost of initial BMP preparation is estimated at \$10,241, while the cost of annual amendments to BMP is estimated at slightly less than half this amount, or \$4,780.

Present values

The proposed regulations have an expected lifespan of ten years. For the purposes of modelling the total costs of BMP preparation over this period, it is assumed that the dates for the five-yearly re-submission of the ESMS, and hence the major revision to the BMP, are evenly distributed. There are five distribution businesses required to submit BMP, as well as two transmission businesses. Table 5.3 sets out the total annual costs of BMP preparation and review under these assumptions and the present value of the BMP preparation requirement over the expected 10 year lifespan of the proposed regulations.

Table 5.3: Aggregate costs of BMP preparation by MECs

Item	Cost
Major BMP revision: 1.4 @ \$10,241	\$14,337 p.a.
Amendments to BMP: 5.6 @ \$4,780	\$26,768 p.a.
Total BMP related costs	\$41,105 p.a.
Present value over 10 years³²	\$341,854

Table 5.3 shows that the cost to distribution businesses of preparing and updating BMP is estimated at \$41,105 per annum, which is equivalent to \$341,854 in present value terms over the expected 10 year life of the proposed regulations.

5.1.3. Cost of BMP Preparation - Specified Operators

³² Consistent with VCEC recommendations, a real discount rate of 3.5% has been used in all present value calculations contained in this RIS.

As discussed above, both MECs and Specified Operators (SOs) are required to prepare BMP. SOs are operators of "at risk" electric lines other than MECs. In practice, this group comprises businesses that operate overhead electricity infrastructure in hazardous bushfire risk areas, but whose main business is not the transmission and/or distribution of electricity. The specified operator category comprises a disparate range of businesses, including those involved in electricity generation, train, rail infrastructure and other major businesses, including Melbourne Water and Alcoa. The Department of Defence is also considered to be a specified operator. A total of eight SOs currently submit BMP to ESV.

Prior to the commencement of amendments to the Electricity Safety Act 1998 and the adoption of the interim regulations in October 2010, the BMP requirements applied to "electricity suppliers". The definition of electricity supplier included all MECs and a proportion of those now classified as specified operators. However, a number of specified operators were brought within the scope of the BMP requirements for the first time as a result of the legislative amendments and the adoption of the interim regulations in 2010.

No data are available on the cost to SOs of BMP preparation. However, given that this group by definition operates electricity assets as an adjunct to its main business activities, it is clear that the scale of its electrical asset infrastructure will be very much smaller than that of MECs. By implication, the scope of the BMPs prepared by this group will also be much more limited. In the absence of quantitative data, it is assumed that the cost per SO of developing and amending BMP will be equal to one quarter of that incurred on average by MEC in completing this task. Thus:

- BMP preparation = $\$10,241 \times 0.25 = \$2,560$
- BMP revision = $\$4,780 \times 0.25 = \$1,195$

There are eight SOs currently required to submit BMP. Given this, Table 5.4 provides estimates of the total cost of BMP preparation for this group, using the same assumptions as those adopted above in respect of Table 5.3.

Table 5.4: Aggregate costs of BMP preparation by specified operators

Item	Cost
Major BMP revision: 1.6 @ \$2,560	\$4,096 p.a.
Amendments to BMP: 6.4 @ \$1,195	\$7,648 p.a.
Total BMP related costs	\$11,744 p.a.
Present value over 10 years³³	\$97,670

³³ Consistent with VCEC recommendations, a real discount rate of 3.5% has been used in all present value calculations contained in this RIS.

5.1.4. Cost of assessment and acceptance of BMP

ESV is required to review draft BMP submitted by MECs and SOs and to accept or not accept the plans. In practice, the process is an iterative one, conducted in consultation with the relevant organisations. It typically involves two reviews of draft BMP, together with a meeting with the company concerned to discuss areas requiring change. Other activities include securing senior management approval, drafting correspondence and the like.

ESV estimates that the average time input required to complete these tasks in relation to a BMP submitted by an MEC is 40 hours. As there are seven MEC required to submit BMP, this implies a total time input of 280 hours.

In addition, ESV must undertake a similar role in relation to BMP submitted by SOs. These plans are typically substantially less detailed than those prepared by MEC, as the scale of the operations involved is much smaller. That said, there is significant variation among SOs as to the extent of their at risk electrical infrastructure. It is estimated that, on average, only around one half of the time required to assess and accept a BMP from an MEC would be required to complete the equivalent tasks in relation to an SO's BMP. Thus, the average time per BMP is 20 hours and the total time required, given a total of eight SOs submitting BMP, is 160 hours annually.

Summing the above two estimates yields a total time input for BMP related activities within ESV of around 440 hours per annum.

The average hourly labour cost of the staff involved in these assessments³⁴ has been calculated at approximately \$75. This implies that the total ESV costs in respect of assessment and approval of BMP is around:

$$\$75 \times 440 = \$33,000$$

It should be noted that the BMP is required to document the strategies by which the MEC or SO will ensure that the 37 month minimum asset inspection frequency and the asset inspector qualification requirements will be met. Thus, the cost to ESV of verifying compliance with these regulatory requirements is, in effect, subsumed within the above estimates.

5.2. Inspection requirements

³⁴ i.e. Salary plus on-costs plus corporate overheads.

As discussed above, the requirement for a maximum 37 month inspection cycle was first introduced in 2010 and was subject to an RIS analysis in 2011. Given that this RIS was very recently developed and published, the data gathered at that time has been used as the basis for the following analysis. However, from a conceptual perspective, the approach taken here is necessarily to focus primarily on the total costs of the inspection requirements, rather than the incremental costs involved. This reflects the fact that the current context is one of sunseting regulation, rather than the amendment of existing requirements³⁵.

5.2.1. Data sources and approaches

In order to obtain the best possible data on the expected costs of compliance with the proposed regulations a questionnaire was developed and sent to a wide range of affected parties during January 2011. The questionnaire sought data on the following issues:

- the cost of complying with the principal regulations as they existed prior to the adoption of the interim regulations;
- the inspection frequencies adopted under the principal regulations;
- the incremental costs expected to be incurred as a result of the provisions contained in the interim regulations and their extension in effect by the proposed regulations; and
- the specific cost impacts of each of the substantive provisions of the proposed regulations.

Questionnaire responses were obtained from all five electricity distribution businesses and from eight "specified operators". The questionnaire responses formed the basis of the following cost estimates. Average cost figures were calculated, in some cases incorporating adjustments or inclusions to take account of identified or suspected data quality issues.

A number of respondents highlighted the commercially sensitive nature of some of the material being supplied and indicated that they did not wish this information to be published in an identifiable form. The questionnaire responses were, in many cases, obtained on the basis of an assurance of compliance with these requests. Consequently, the following estimates are presented in aggregated form and only a limited amount of more disaggregated material has been able to be provided.

5.3. Incremental costs: electricity distribution businesses

5.3.1. Current arrangements

For electricity distribution businesses, the annual cost of inspecting power lines pursuant to BMPs under the arrangements in place until 2010 (i.e. prior to the adoption of the prescriptive inspection

³⁵ See the Victorian Guide to Regulation for an explanation of these conceptual issues.

requirements in the interim regulations) was estimated at \$8.6 million. Inspection activity was largely carried out under contract by third parties and the costs incurred varied little from year to year. Inspection intervals ranged from 3 to 5 yearly in most cases, with a 10 year interval being common for concrete power poles.

Some respondents to the 2011 questionnaire noted, however, that significant recent changes to their previous practices had already been made. These changes reflected, in part, a desire to adopt new technology to improve the effectiveness of inspections and lower their costs, in the pursuit of business efficiencies. They also reflected, in part, the companies' response to the recommendations of the VBRC report and its recommendations.

Two related changes to inspection practices were identified that are currently in the process of being implemented. These are the use of high resolution digital photography and the use of aerial inspections. Digital photography is used to obtain better information as to the state of pole-top fittings, in a context in which it is necessary as a matter of practicability to conduct most inspections from ground level. Remote devices are employed in most cases to assist in obtaining better images. However, the use of aerial photography - specifically by mounting digital cameras on helicopters - was increasingly being adopted as a means of conducting some inspection activity, with one major distribution business currently having already adopted an aerial inspection program to supplement its program of ground based inspections, while the second major distribution business affected by the proposed regulations had indicated its intention to move in this direction, subject to the regulations being interpreted in a way that would allow this to occur.

In the course of assessing and accepting subsequent BMP, ESV has reviewed the use of aerial inspections and reached the view that this technology is an effective one that should be accepted for the purposes of compliance with the minimum inspection frequency requirements of the current regulations. In reaching this view, key considerations were that:

- The use of high definition digital photography from an aerial platform (i.e. a helicopter) provided better imaging in respect of pole-top hardware and thus enabled more reliable identification of maintenance needs; and
- While aerial photography does not allow poles to be inspected, historical data indicates that failure of poles is not a significant concern in terms of bushfire ignition.

Thus, on balance, aerial photography was found to be likely to be at least as effective as traditional inspection mechanisms and to be appropriately used, particularly in conjunction with other mechanisms, as has been proposed by distribution businesses.

The incremental cost estimates provided in 2011 by distribution businesses contained two scenarios, which differed according to the question of whether aerial inspections would be accepted by ESV for regulatory purposes. Given that aerial inspections have now been accepted, the cost estimates

contained in this scenario are used below as the basis for costing the inspection requirements of the proposed regulations.

5.3.2. Incremental costs of 37 month inspection cycle

As noted above, a limitation of aerial photography as an inspection mechanism is that it does not allow for a direct assessment of the structural integrity of the electricity pole itself to be made. Consequently, the preferred approach identified by distribution businesses is to use a mix of aerial and ground based inspections, with assets being inspected by both means on an alternating schedule. It is therefore likely that modified BMP submitted to comply with the regulations currently adopt this approach, implying that assets in high bushfire risk areas would receive either a ground based or an aerial inspection at least every 37 months.

Table 5.5, below, is based on responses to a questionnaire sent to the MECs in January 2011 - i.e. shortly after the commencement of the interim regulations that first established the 37 month inspection cycle. The questionnaire sought data on the following issues:

- the cost of complying with the principal regulations as they existed prior to the adoption of the interim regulations;
- the inspection frequencies adopted under the principal regulations;
- the incremental costs expected to be incurred as a result of the provisions contained in the interim regulations and their extension in effect by the proposed regulations; and
- the specific cost impacts of each of the substantive provisions of the proposed regulations.

Questionnaire responses were obtained from all five electricity distribution businesses. The data received included the aggregate inspection cost and the number of poles inspected, allowing verification of the data estimates via calculation of "cost per pole" estimates, which were found to be broadly comparable. The responses received in relation to the costs of both the existing inspection cycle and the adoption of the 37 month inspection cycle have been aggregated and are presented in Table 5.5.³⁶

Table 5.5. summarises the total costs of inspection activities and highlights the incremental costs of the prescription of a 37 month maximum inspection cycle, implemented from 2010. It should be noted that the two distribution companies responsible for the bulk of the electricity assets located in HBRA both indicated that their least cost response to the need to comply with the prescriptive inspection cycle requirement adopted in 2010 would be to move from their current 5 year inspection cycle to a 2.5 year cycle, rather than the minimum 37 month cycle specified in the regulations.

³⁶ Note that the data presented here were first reported in the RIS in respect of the Electricity Safety (Bushfire Mitigation)(Amendment) Regulations 2011. However, that RIS included cost estimates based on two different scenarios: one in which ESV would accept inspection strategies that incorporated aerial inspections and another based on the rejection of this technology. Given that ESV has since accepted the use of aerial inspections, only the data based on the former scenario is reported here.

Table 5.5: Cost of moving to a 37 month inspection cycle

	Annual average	Present value over 10 years
Pre-2010 inspection cost	\$8.6 million	\$71.5 million
Inspection cost	\$10.6 million	\$88.2 million
Incremental cost	\$2.0 million (+23.3%)	\$16.6 million

Table 5.5 shows that the average annual cost to the affected electricity distribution businesses of conducting inspections of at risk electricity assets on a 37 month minimum cycle, as per the proposed regulations, is \$10.6 million. This is equal to \$88.2 million in present value terms over the expected 10 year life of the proposed regulations. Table 5.5 also shows that the move to a 37 month inspection regime, implemented in 2010, is estimated to have increased this cost by \$2.0 million per annum, or around 23.3%, compared with the inspection regimes previously in place.

5.3.3. Cost of qualifications requirements for inspectors

As noted above, all distribution businesses state that most or all of their inspection activity was contracted to third parties. Given this, the major impact of the qualifications requirements adopted in 2010 was expected to be an increase in the contracted cost per inspection, as a result of the need for contractors to recover the costs of training their employees to the required standard. Completing the Certificate II in Asset Inspection requires the accumulation of 360 course points, equivalent to around nine units of study.

Two respondents estimated this cost as an ongoing 10% increase in inspection costs. A third respondent was unable to provide an estimate of this cost. A fourth respondent provided "one off" cost estimates equal to approximately 16 - 17% of the estimated annual cost of inspection under a 37 month inspection cycle.

It can be expected that providers of inspection services will need to train existing staff to a level consistent with the required qualifications, to hire staff who possess these qualifications or, most likely, to undertake some combination of these two courses. This implies that they will incur some short-term training costs and some ongoing costs in the form of the need to pay higher wages to qualified staff. Given that they operate in a competitive market, it can be expected that they would seek to recover these costs through higher contract prices for undertaking inspection activity, rather than seeking to pass on the short-term costs of training activity. Thus, in an environment in which all distribution businesses state that they employ third parties to undertake the required inspection activity, it is considered preferable to model the impact of the proposed qualifications requirement as an ongoing increase in unit inspection costs, rather than as a one-off increase. Thus, the cost of the qualifications requirements has been modelled as an ongoing 10% increase in inspection costs.

The total cost of inspection activity under the proposed regulations was estimated above at \$10.6 million annually, based on the previous arrangements under which no qualifications requirements existed. This implies that the incremental costs of the qualifications requirements are around \$1.06 million per annum. This is equal to \$8.8 million in present value terms over the expected 10 year life of the proposed regulations.

5.3.4. Costs of 61 month inspection cycle - LBRA

As noted in Section 4, Regulation 7 also effectively requires that overhead electricity assets in LBRA must be inspected at intervals not exceeding 61 months. Specifically, the regulation requires that the BMP include an inspection plan that would ensure this outcome.

This is a new requirement, not contained in the existing regulations. However, it has been adopted following consultation with the relevant distribution businesses which has indicated that their current practices are broadly compliant with this standard. Thus, one DB indicated that it currently has an inspection cycle of 63 months, while the remaining DBs indicated that they currently adopt a 61 month standard. The DBs advise that, in practice, they aim to complete the inspection cycle within five years, but that small additional allowances are included in their plans to account for unforeseen or unexpected issues, such as wet weather or an uncooperative land owner, which may prevent a scheduled inspection from taking place within the five year period.

Given that 5 years is the standard inspection interval in LBRA for all DBs and that a (slightly) longer inspection interval is only intended to be a contingency if needed, ESV does not believe that the formal specification of a 61 month maximum inspection cycle in these circumstances will, in practice, result in any additional inspection costs being incurred. Conversely, specification of the maximum inspection cycle ensures that no reduction in inspection frequency will be possible, or sought, during the life of the proposed regulations.

5.3.5. Incremental costs of monitoring and review activities

As noted in Section 4, the proposed regulations also contain specific requirements for the monitoring of BMP implementation and the identification of deficiencies, including monitoring of the effectiveness of the inspection program and addressing any deficiencies found.

Four distribution businesses have indicated that they will incur additional costs as a result of these provisions, while the fifth believed that their existing processes in this regard would be regarded as compliant. In each case, the potential additional costs identified related to engaging external auditors to demonstrate that the required assessments had been undertaken.

Four of the five distribution businesses consulted argued that they would incur additional costs in meeting these requirements. Two estimated the additional costs involved at \$50,000 per annum, while a third estimated the costs at \$100,000 per annum. The fourth distribution business stated that they believed their existing processes to be adequate but argued that they could possibly incur costs of up to \$500,000 in demonstrating compliance to the satisfaction of ESV. Given the nature of these estimated costs and the contrast between this estimate and those of the other distribution businesses, a revised estimate of \$100,000 was adopted in the 2011 RIS, yielding a total cost of \$300,000 per annum to meet these additional requirements. ESV's subsequent implementation experience suggests that the actual costs incurred may have been less than this amount. However, for current purposes, the estimate of \$300,000 per annum is retained.

5.3.6. Other identified costs

The questionnaire also asked respondents to identify any other costs that would be incurred as a result of the provisions contained in the interim regulations and the proposed regulations. Costs of training internally employed inspectors were identified by two distribution businesses, notwithstanding that they stated that their inspection activities were substantially completed by third parties. It can be speculated that these businesses maintain some degree of internal inspection capacity in addition to the employment of externally contracted services, potentially in order to be able to respond to specific issues highlighted to them.

The ongoing costs of additional training of internally employed inspectors was expected to total \$30,000 per annum, with the ongoing nature of this cost described as being the result of expected labour turnover. No other businesses identified additional costs. Thus, the total cost identified among MECs was \$30,000 per annum. This is equal to approximately \$250,000 over 10 years in present value terms.

5.3.7. Additional maintenance costs

In general, the proposed requirements for more frequent and higher quality inspections to be undertaken are predicated on the view that an improved inspection regime will lead to earlier identification of faults in electricity lines, enabling these faults to be addressed in a more timely manner and thereby reducing the incidence of failures leading to bushfire ignition. In large part, it is expected that the need to address this larger number of identified faults over the medium term will result in reallocation of expenditures within the existing maintenance budget.

This reflects the basis of the system of economic regulation governing the industry, in which maintenance budgets are agreed as part of the five-yearly price reset process overseen by the Australian Energy Regulator. Questionnaire responses indicated that affected parties largely expected to meet

their obligations under the proposed regulations within the context of current price/revenue/cost arrangements.

Conceptually, therefore, the expected benefits of the regulations are expected largely to be obtained by means of a reallocation of maintenance expenditures to higher-productivity ends. However, given the possibility that additional expenditures could be required in order to respond in a timely way to all critical faults identified through the enhanced inspection regime, respondents were asked to estimate the size of any additional maintenance costs that they expected to incur.

Only one MEC stated that they expected maintenance expenditures to be brought forward to some degree. That respondent nominated a five-year time horizon over which this impact was expected to be felt and estimated that maintenance expenditures could increase by around \$50,000 per annum over this time. One other respondent characterised the expected increase in maintenance expenditures as being "negligible", while others did not identify any additional costs. One specified operator also referred to the possibility that expenditures would be brought forward, but provided no quantitative estimate. It must be noted that, to the extent that maintenance expenditures are brought forward, the net cost involved is not equal to the amount of the expenditure brought forward. Rather, it is equal to the difference between the present value of that expenditure at the time that it would have been incurred (i.e. in the absence of the 37 month inspection cycle) and the present value of the expenditure at the time that it will be incurred in the presence of the 37 month inspection cycle.

Given these estimates and the fact that the 37 month inspection regime will have been in place for approximately three years by the time the proposed regulations are due to come into effect, no incremental costs have been included in this analysis in respect of this factor.

5.4. Costs to specified operators

5.4.1. Inspection arrangements prior to the adoption of the 37 month cycle

Six specified operators provided estimates of the inspection costs they incurred prior to the adoption of the recent changes. Given that this group had not, at that time, been subject to the BMP requirements, these costs can be considered to be "business as usual" costs; that is, costs that are incurred by these companies for commercial reasons. These reported *ex ante* costs varied widely, from \$600 to \$181,400 per annum, reflecting the widely varying nature and scale of the at risk electrical lines operated by these companies. This wide variation in turn reflects the widely differing nature of the activities undertaken by these firms. The variation observed necessarily introduces an element of uncertainty as to the calculation of average costs for this group. However, the six responses received from operators in this sector represent approximately three quarters of the companies affected by the proposed regulations. Hence, estimates based on these responses are likely to be reasonably representative.

The total annual cost of current inspection activity among the six respondent companies was \$261,700, implying average annual costs per company of \$43,600.

5.4.2. Incremental costs of 37 month inspection cycle

Four of the respondents provided quantitative estimates of the incremental costs of moving to a 37 month minimum inspection frequency. Two of these respondents stated that there would be no impact on their operations, as their current inspection frequency already met or exceeded the proposed requirements. The remaining two respondents estimated cost increases of \$7,000 and \$15,000 per annum. Thus, the total cost increase among this group of four respondents was expected to be \$22,000 per annum and the average increase per respondent was \$5,500 per annum.

Given that eight specified operators are currently submitting BMP to ESV, this implies that the incremental costs for this group as a whole of moving to a 37 month minimum inspection cycle are of the order of $(8 \times \$5,500) = \$44,000$ per annum. This is equal to approximately \$0.4 million in present value terms over 10 years.

5.4.3. Incremental costs of qualifications requirements

Responses to the question of what would be the cost impact of the proposed requirement for all inspectors to meet minimum qualifications standards varied widely among this group. Seven responses were received to this question. Two respondents indicated that there would be a zero or minimal cost impact. Both of these respondents undertook relatively large-scale inspection activities, with one contracting this activity to a third party and the other undertaking a mix of in-house and third party inspections. A third respondent estimated the cost increase at 11%, while a fourth estimated a 20-30% increase. These respondents also had relatively large scale inspection activities and contracted these tasks to third parties.

Two respondents whose current costs were very small estimated increases of 67% and 100% respectively. In one case this was based on an assessment that they would move from their current internal inspection regime to an external regime. In the other case, it was anticipated that they would train their current internal inspectors to the required standard. The seventh response was speculative in nature and, given the absence of a specific estimate of current inspection costs, cannot be assessed in terms of a proportionate increase. This response has therefore been excluded from the analysis.

The total incremental cost among the six respondents was \$29,100. This represented an increase of 11.1% on the current cost base of \$261,700 for this group and an average increase of \$4,850 per respondent. On the basis of an estimated 8 affected operators, the expected annual cost of the qualifications requirements is \$38,800.

5.4.4. Incremental costs of monitoring and review activities

Six responses were received to the questions regarding the incremental cost of these requirements. Three of the respondents stated that they did not expect to incur any additional costs as they believed that their current monitoring and review arrangements would be held to be compliant with the new requirements. A fourth respondent noted that they already employed an external auditor for this purpose but speculated that they may increase the amount of external audit activity, at a cost of around \$1,000 per annum.

Neither of the two remaining respondents currently employed an external auditor and both speculated that they may need to take this step in order to comply with the requirements. However, estimates of the likely incremental costs varied widely, with one estimate at \$1,000 and the second at \$10,000. While this respondent has relatively large scale electricity assets, this estimate is clearly well outside the range of the remaining five respondents and may be somewhat speculative in nature.

The average incremental cost of monitoring and review activities is \$2,000 per respondent. Given the 8 specified operators expected to be affected by the proposed regulations, this implies total annual costs of \$16,000.

5.4.5. Other identified costs

Four responses were received to the question of whether any other cost impacts could be identified in connection with the proposed regulations. Two respondents stated that they did not foresee any additional costs, while a third stated that they had not yet assessed this question. Only one respondent identified specific additional costs. These were costs of \$8,300 per annum approximately arising due to an expectation that increased inspection activity would lead to a higher rate of electricity outages. That is, this estimate was predicated on an assumption that lines could not be live when inspection was being undertaken.

The average expected cost in this regard is therefore approximately \$2,075 per annum. Given the expectation of eight affected entities, the average of "other" identified costs is therefore \$16,600 per annum.

5.4.6. Increased maintenance costs

Five responses were received to the question of whether and by how much maintenance costs were expected to increase as a result of the enhanced regulatory inspection requirements. Four stated that they did not expect any significant increase in maintenance costs to result. The fifth respondent stated that they had yet to undertake a quantitative assessment of likely maintenance costs but that they

considered it possible that these could be increased by between 20% and 50%. However, no dollar figure on either current maintenance expenditure or expected increases in maintenance expenditures were provided.

Overall, the responses received were consistent with those of the distribution businesses, which indicated that they did not believe that increased inspections would yield significant or measurable changes in maintenance expenditures.

5.4.7. Costs to ESV

ESV has not incurred any additional costs in connection with either the 37 month inspection requirement or the qualification requirement for inspectors since the adoption of these provisions in the interim regulations in late 2010. Given that these requirements would be unchanged under the proposed regulations, it does not anticipate any additional costs arising in this respect in the future.

Verification of compliance occurs in two ways. First, this occurs through the process of reviewing and accepting BMPs, since these documents are required to include descriptions of the strategies that will be adopted by MECs to ensure compliance with the inspection requirements. Second, ESV undertakes bushfire mitigation audits to verify MEC compliance with their BMPs. However, as ESV's auditing powers derive from the ES Act, these audit costs are attributable to the Act itself, rather than the regulations, and are beyond the scope of the current analysis.

5.5. Cost summary

Tables 5.6 - 5.9, below, summarise the above cost analysis. The costs presented in Tables 5.5 and 5.6 represent the increases in the former "business as usual" costs that have been attributed to the adoption of the inspection frequency and qualifications requirements into the existing regulations in 2010. Table 5.6 shows that the annual costs attributable to the regulations total \$3.39 million for distribution businesses, which is equal to \$28.2 million in present value terms across the life of the proposed regulations. The costs incurred by specified operators are much smaller, being \$115,400 per annum or approximately \$1.0 million in present value terms over 10 year.

Table 5.6: Total costs of inspection related requirements - distribution businesses

	Annual costs	Present values (10 years)
Inspection costs	\$2.0 million	\$16.6 million
Qualifications	\$1.06 million	\$8.8 million
Monitoring & review	\$0.3 million	\$2.5 million
Other (training)	\$0.03 million	\$0.25 million

Total	\$3.39 million	\$28.2 million
--------------	-----------------------	-----------------------

Table 5.7: Total costs of inspection-related requirements - specified operators

Item	Annual cost	Present value (10 years)
Shortened inspection cycle	\$44,000	\$365,931
Qualifications requirements	\$38,800	\$322,684
Monitoring and review	\$16,000	\$133,066
Other	\$16,600	\$138,056
Total	\$115,400	\$959,736

Table 5.8 summarises the costs of preparing and amending BMP, as set out in Section 5.1, above. These costs total \$29,361 per annum for distribution businesses, which is equivalent to \$244,184 in present value terms over 10 years. No equivalent cost estimates have been obtained from specified operators. However, as tables 5.5 and 5.6 show, the substantially smaller scale of the at risk electricity assets owned by specified operators mean that the costs that they incur in relation to the regulatory requirements is substantially smaller than those incurred by distribution businesses: the present value of the inspection-related costs imposed by the regulations over ten years is estimated at \$28.2 million for distribution businesses, compared with only \$1.0 million for specified operators.

These observations, taken together with the very small size of the identified cost of BMP preparation relative to the costs of the inspection requirements, suggest that the costs that specified operators incur in preparing and amending BMP are very small relative to the overall costs imposed by the proposed regulations.

Table 5.8 Aggregate costs of BMP preparation

Item	Annual Cost (DBs)	Annual Cost (SOs)
Major BMP revisions	\$14,337.	\$4,096
Amendments to BMP	\$26,768	\$7,648
Total BMP related costs	\$41,105	\$11,744
Present value over 10 years	\$341,854	\$97,670

Table 5.9 summarises the total estimated costs of the proposed regulations. These costs can be considered as being calculated against an unregulated base case. That is, they reflect the increase in the costs that would be incurred under a "business as usual" scenario as a result of the regulations' requirements that affected parties prepare BMP and ensure that inspection is undertaken by qualified individuals at intervals of no more than 37 months. Table 5.8 shows that the estimated annual cost of

the proposed regulations is approximately \$3.6 million, which is equivalent to \$29.9 million in present value terms over 10 years.

It should be noted, however, that the incremental costs of the proposed regulations - that is, the difference in regulatory costs between the current and proposed regulations - is, in effect, zero. This reflects the fact that the proposed regulations are substantively identical to the existing regulations.

Table 5.9: Total costs of the proposed regulations

Item	Cost per year	Present value (10 years)
BMP Preparation - DBs	\$41,105	\$341,854
BMP Preparation - SOs	\$11,744	\$97,670
BMP assessment/acceptance - ESV	\$33,000	\$274,448
Inspection requirements - DBs	\$3,390,000	\$28,200,000
Inspection requirements - SOs	\$115,400	\$959,736
Total cost	\$3,591,249	\$29,873,708

6. Expected benefits of the proposed regulations

6.1. Overview

As noted above, the expected benefits of the proposed regulations arise from anticipated reductions in the incidence of bushfire caused by failures of electricity assets. These reductions are expected to arise as a result of improved maintenance performance. Both the adoption of a prescribed minimum inspection frequency greater than that previously adopted in practice (in conjunction with quality safeguards) and the requirement to document bushfire mitigation policies and strategies in a formal BMP with a range of specified inclusions are expected to contribute to this goal. The following sections discuss the means by which these regulatory requirements are expected to yield these benefits.

6.1.1. Benefits of specifying inspection frequency and inspector qualifications

The changes in inspection frequency and quality that have resulted from the adoption of the prescriptive inspection requirements in 2010, and would continue under the proposed regulations, are expected to lead to faults being identified earlier than at present, on average, and corrective action consequently being taken at an earlier stage. Better maintenance should lead to a reduced failure rate and, consequently, a reduced incidence of bushfire ignition.

The extent of the improvement that can be anticipated is necessarily uncertain. In large part, this uncertainty derives from the relatively limited frequency of bushfires and the still more limited frequency of bushfires ignited by electricity assets. In addition, there is clearly uncertainty as to the likely practical effectiveness of the proposed regulatory changes in improving actual maintenance practices.

However, the questionnaire responses received provide some guidance on this issue. The responses from the major electricity companies who operate the majority of electricity assets in bushfire prone areas, indicated that the most common inspection frequency prior to the adoption of the current requirements in 2010 was five years, or ten years in the case of concrete electricity poles. Questionnaire responses indicated that, in most cases, there would be a move to conducting inspections at 2.5 year intervals in response to the proposed regulations. While a 37 month interval is allowed in the regulations, key respondents indicated that a 2.5 year cycle would be likely to be chosen as this harmonised better with other aspects of their companies' commercial operations. Subsequent experience shows that these distribution businesses have, in practice, adopted a nominal 2.5 year inspection cycle, meaning that assets are inspected on average at 2.5 year intervals.

Given this, it appears that there will be an approximate doubling in the number of inspections carried out in relation to most assets in high bushfire risk areas, as well as an improvement in the average quality of inspections due to the implementation of qualifications requirements for inspectors. A doubling of inspection frequency should substantially reduce the period elapsing between a fault occurring and that fault being detected and remedied before the asset can fail while in service. Thus, the impact of the proposed regulations could be quite large.

That said, one large distribution business indicated that they did not believe that significant changes to fault detection and maintenance practice would occur as a result of the implementation of these regulations. This business argued that its current inspection program is based on an explicit analysis of maintenance requirements and that the soundness of this analysis is demonstrated by the small number of in-service power-line asset failures currently experienced.

Moreover, this organisation noted specifically that analysis of the current five year maintenance cycle showed no correlation between the time elapsed since an inspection had been conducted and the likelihood of an asset failure. That is, failures occurred equally frequently among recently inspected assets and those approaching the time for their next scheduled inspections. This observation can clearly be interpreted as indicating that the current inspection frequency is adequate. Conversely, two factors can be weighed:

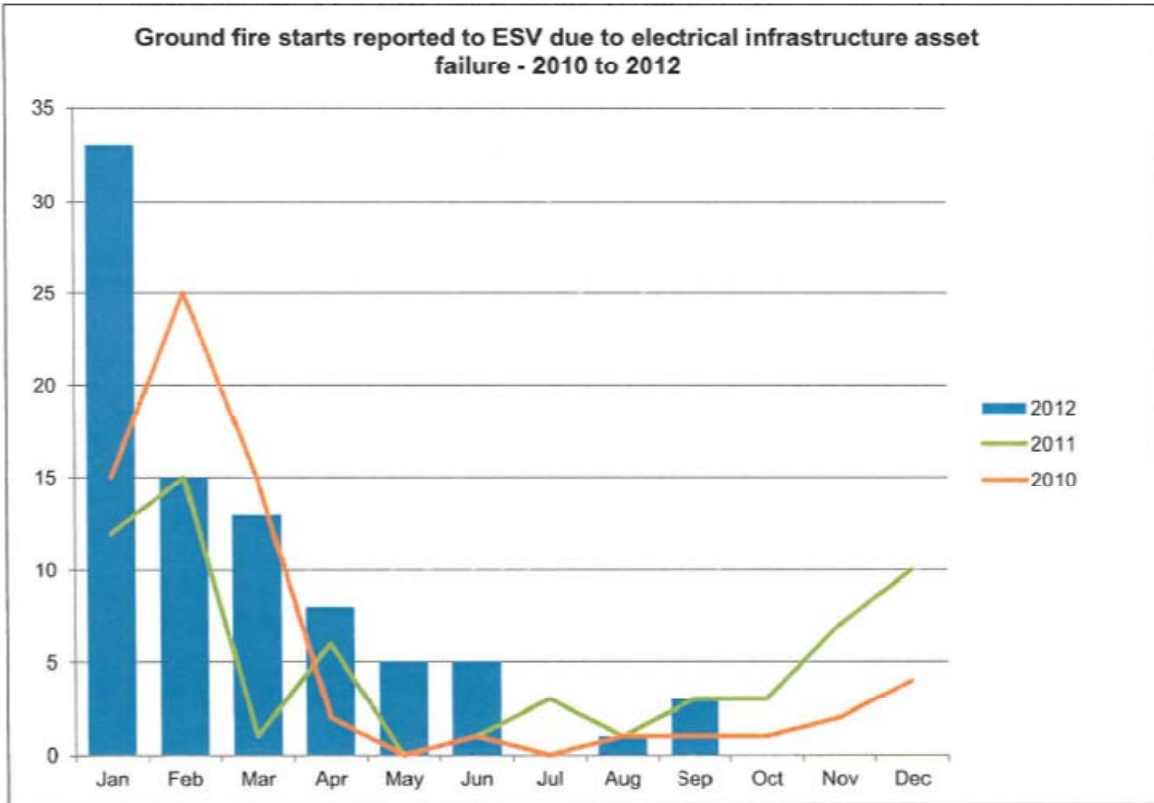
- That a poor failure identification rate during inspections could reduce the observed correlation between inspection time and failures; and
- That the increasing average age of electricity assets implies a need for inspection frequencies to be increased in the future, as suggested by the VBRC.

Another factor that can be noted is that the major distribution businesses were already, at the time of the adoption of the 2010 amendments, moving toward the use of aerial inspection methods in conjunction with traditional approaches. .

Data trends since the adoption of the interim regulations

As discussed in Section 9, distribution businesses are required to report incidents and fire starts relating to electricity assets to ESV, which uses these reports to produce aggregated data. Graph 6.1, below, is reproduced from ESV's Business Performance Report and contains data on fire starts due to electricity asset failures up to, and including, September 2012.

Graph 6.1: Fire Starts Due to Electricity Asset Failures: 2010 to 2012



Source: ESV Business Performance Report, October 2012

Graph 6.1 shows that ground fire starts due to electrical asset failures have a highly seasonal pattern, with the great majority of fires occurring in the summer months. Comparison of the data for 2010, 2011 and 2012 does not demonstrate any clear trend in the number of ground fires, despite the fact that the interim regulations have been in place since October 2010. However, this result is not unexpected, for several reasons.

- First, the relatively low absolute number of fires and substantial variability in the numbers mean that the impact of random variations can be expected to be substantial and to have the potential to obscure any actual trends.
- Second, as the seasonal pattern indicates, climatic factors have a substantial impact on the likelihood of fire starts. This, equally, implies that year to year variation in weather patterns are also likely to affect substantially the observed number of fires, independent of any underlying trends.
- Third, the impact of the increased inspection frequency and the associated bringing forward of maintenance expenditures will necessarily be felt over several years, implying that the

improvement in asset safety performance that is expected to result will only be fully observable over the medium term.

In sum, the available data on ground fire starts due to electricity asset failure do not, at this stage, provide any direct evidence of the effectiveness of the changes to the asset inspection regime adopted in the October 2010 interim regulations. However, given the nature of the changes and the environment in which they are operating, this is an unsurprising result and does not suggest that the changes have been, or will be, ineffective over the medium term.

6.1.2. Benefits of prescribing BMP content

As discussed in Section 3, the requirement to prepare BMP is established in the Electricity Safety Act 1998. This means that, even were the proposed regulations not to proceed, the relevant MECs and SOs would be required to prepare BMP, to submit them and have them approved by ESV. The Act, however, provides only very limited guidance as to the content of BMP, stating that BMP must demonstrate how the regulated parties will comply with those general duties.

Even in the absence of further guidance, regulated entities would need to submit BMP that substantively addressed their approach to acquitting the general duties and that were set out in a form that could reasonably be judged to meet the description of a "Bushfire Management Plan". Moreover, in the absence of specific regulatory requirements regarding the content of BMP, ESV would find it necessary to issue guidelines on this issue. Indeed, it is likely that the regulated parties would actively lobby for such guidance, given that the Act requires ESV to determine whether to accept a proposed BMP and appears to give it relatively wide discretion as to whether or not a particular BMP is accepted.

In this context, the impact of regulating to establish the specific content of BMP arguably lies primarily in setting out clearly and transparently the minimum required content of the BMP and in ensuring the enforceability of ESV's view as to the appropriate scope and content of the document. By contrast, an approach based on guidance material would be less transparent to stakeholders and the public, since the guidance material would not be subject to RIS scrutiny, or even necessarily be published. Moreover, under a guidance based approach, ESV could ultimately be limited in its ability to require certain material to be included in the BMP.

Taking a broader view, the specification of particular content within the BMP context is a mechanism by which ESV is better able to ensure on an *ex ante* basis that regulated entities have developed appropriate processes and procedures to enable them to comply on a systematic basis with the general duties placed on them by the Act to minimise as far as practicable the risk of bushfire ignition due to the operation of electricity assets. This, in turn, supports ESV in requiring remedial action to be undertaken where it is not satisfied on these issues.

6.2. Break-even analysis

In light of the necessary level of uncertainty that exists as to the extent of the effects on bushfire mitigation of the two key elements of the proposed regulations, a break-even analysis has been developed below. The results of this analysis are compared with the identified costs and analysed in the conclusions section following.

Section 3.2 shows that, based on a BTRE study published in 2001, with the results updated to reflect current dollar values, the average annual cost of bushfires in Victoria in the period 1967 to 1999 was in the range \$70 million - \$105 million. However, this was shown to be a somewhat conservative estimate that appears to have excluded the value of forestry losses from the calculations undertaken. Moreover, the inclusion of the Black Saturday fires in the dataset clearly increases the long-term average cost of bushfire, while predictions in relation to the impact of climate change on bushfire incidence suggests that this higher average incidence of fires will be maintained over time and even increase further.

Thus, based on the more comprehensive VBRC data also set out in Section 3, Victoria has faced a major bushfire approximately every 2.5 years over the past 160 years. Several estimates of the average cost of such fires can be identified. These are:

- The analysis conducted by the Bureau of Transport and Regional Economics, adjusted to present the results in present dollar values and based on currently accepted VSL figures, which suggests that the average cost per bushfire, Australia-wide, lies in the range \$245.5 - 368.2 million;
- The VBRC's analysis, indicating that the average cost for each of the 15 major Black Saturday fires that it investigated was approximately \$300 million;
- The \$300 million estimated cost of the 2003 Canberra bushfires; and
- The \$400 million estimated cost of 1983 Ash Wednesday fires in Victoria.

Given these data, an estimate for the average cost of a major bushfire of \$300 million has been adopted for the purposes of this analysis. This implies that the average annual cost to Victoria of major bushfires is $\$300/2.5 = \120 million.

The second factor to be considered is the contribution of electricity assets to bushfire ignition. The VBRC found that in long-term average terms, only around 1.5% of bushfire ignitions were due to electricity assets. However, the likely contribution of electricity assets to the cost of bushfires is much greater than this figure would suggest, since the likelihood of ignition due to electricity assets is much higher when weather conditions are such as to lead to an elevated likelihood of a fire developing into a major fire, leading to large scale losses. Thus, the contribution of electricity assets to losses from bushfires is much larger than their contribution to bushfire ignitions. The VBRC found³⁷ that that major fatal fires had been ignited due to electricity asset failures in 1969, 1977 and 1983. Specifically:

³⁷ See: Victorian Bushfire Commission (2009). *Final Report*, Vol 2, Chapter 4.

- 9 of 16 major fires occurring on February 16, 1977 were caused by electricity assets;
- 4 of 8 fires occurring on Ash Wednesday 1983 were caused by electricity assets; and
- 5 of 11 major fires occurring on Black Saturday 2009 were caused by electricity assets.

Moreover, 70% of the 173 deaths due to the Black Saturday fires resulted from fires ignited by electricity asset failures. The Commission also cited evidence to the inquiry into the 1977 fires from the then Chairman of the State Electricity Commission, as follows:

" This overall picture is in sharp contrast to what happens on days of extreme conditions, such as January 8th 1969 or February 12th 1977. On such days, the incidence of SEC fires rises dramatically.

The alarming aspect of these figures is that they tend to occur in widely separated places at approximately the same time and at the time of day when conditions are such that the rate of spread of fire is likely to be at its peak"

Based on these factors, and in particular the observation that 50% of major fires occurring on each of last three occasions on which disastrous bushfires occurred in Victoria (i.e in 1977, 1983 and 2009), it is speculated that the contribution of electricity assets to losses from major bushfires is in the order of 50%. Moreover, the ageing of the electricity infrastructure, as highlighted by the Commission, suggests that this percentage would be likely to increase in future years in the absence of any policy action. As discussed in Section 3, above, the VBRC cited a range of research which indicated that rapidly increasing equipment failures could be expected in the near future in the absence of significant changes to the management of electricity assets. This implies that the contribution of electricity assets to losses from bushfires would be likely to reach this 50% level in the near future, in the absence of policy action, even if the current contribution of electricity assets to losses is judged to be likely to be smaller than this amount.

Thus, the base case scenario suggests that around \$120 million x 50% = \$60 million per annum in bushfire related costs, on average, would be incurred in the future due to failures in electricity assets, in the absence of policy action such as the adoption of the proposed regulations.

The annual costs of the proposed regulations have been estimated at around \$3.6 million. This implies that the regulations will break even - i.e. that the benefits associated with the regulations will at least equal the costs incurred - if they are responsible for a reduction in electricity asset-related losses from bushfires of around $(\$3.6m/\$60m) = 6.0\%$.

7. Identification and analysis of feasible alternatives

Overview

The above analysis has demonstrated clearly that the substantial majority of the costs imposed by the proposed regulations are attributable to the provisions specifying minimum inspection frequencies for at risk assets, together with qualifications requirements for inspectors. This fact implies that any feasible alternatives to the proposed regulations identified should focus on the issue of regulating inspection quality and/or frequency.

Four alternatives to the proposed regulations have been identified. The first of these is very similar to the proposed regulations and differs only in that, in line with VBRC Recommendation 28, it would limit the requirement for a maximum three year inspection cycle to SWER lines and 22kV feeder lines, rather than applying it to electrical assets in high bushfire risk areas.

The second and third alternatives differ from the proposed regulations in that they would apply maximum inspection frequency requirements that varied with asset age, whereas the proposed regulations set a single inspection frequency for all electricity assets in high bushfire risk areas. The alternative approach of applying differentiated inspection frequency requirements is based on the observed relationship between expected failure rates and asset age, as represented in Graph 3.1, above. Alternatives of this type therefore constitute examples of a *risk based assessment regime*, which is increasingly seen as a regulatory best practice³⁸. The key benefit expected to result from adoption of such an approach is increased effectiveness of inspection activity. That is, because inspection activity is more closely focused on older assets known to be more likely to fail.

This improvement in effectiveness has the potential to ensure that a larger proportion of imminent asset failures will be detected and remedied in a timely manner than would otherwise be the case, for a given inspection budget. Alternatively, as indicated in the Hampton Report, a given level of inspection effectiveness can potentially be achieved at lower cost. Alternative 1, below, focuses on using inspection targeting based on asset age as a means of increasing fault detection rates. Alternative 2, on the other hand, focuses on the potential for such targeting to reduce the cost of achieving a given level of fault detection via asset inspections.

The fourth alternative discussed below would regulate the qualifications of asset inspectors, without requiring a specific frequency of inspection. Rather, the existing arrangement in which the asset inspection frequency proposed by the electricity company would need to be assessed and approved by ESV in the context of the overall BMP proposal would be retained. This alternative has the benefit of

³⁸ See, for example, Hampton, P. (2005). *Reducing Administrative Burdens: Effective Inspection and Enforcement*. HM Treasury, United Kingdom Government.

retaining flexibility regarding asset inspections in recognition of different circumstances and different broad approaches to mitigating bushfire risk.

Interstate requirements

It is a requirement of the Victorian Guide to Regulation that consideration should be given to the approaches taken to dealing with an identified regulatory problem in other Australian States and Territories and, where a less onerous approach is adopted in other states, evidence should be provided as to why this is not appropriate in the Victorian context.

ESV understands that no other state currently regulates the required qualifications of asset inspectors or the frequency of asset inspections. Following the disaggregation and privatisation of the Victorian electricity supply industry, the government established an independent economic and technical safety regulatory regime which, amongst other things, required the submission of plans for approval as well as the setting of standards and procedures in a number of work practice areas. Although largely outcome-based, the Victorian regulatory regime was specifically designed to ensure that, where industry had demonstrated a manifest failure to respond to either commercial or incentive arrangements, independent and prescriptive regulation could be introduced to address particular failures and/or risks being taken by privatised businesses. Failure in the areas of asset inspection by distribution companies, as well as the lack of training of asset inspectors, was identified by the VBRC as a significant contributing factor leading to the failure of electricity systems and the cause of at least 5 of the 8 major fires on Black Saturday. The regulatory response in relation to asset inspection, frequency and training was in direct response to specific recommendations made by the VBRC and accepted by government.

Even though similar standards are being or are likely to be adopted in other states as best practice, the norm in other states has been not to explicitly regulate these activities. This is because, apart from South Australia, the network businesses in every other state are publicly-owned monopoly businesses and, whilst corporatised, they are still subject to government or ministerial direction, thus obviating the need to explicitly regulate in these areas.

Notwithstanding, a number of interstate distribution network companies are already giving consideration to adopting the Certificate II in Asset Inspection, which will shortly become a nationally accredited qualification that can then be taken up by the network companies as internal policy or mandated through regulation.

7.1. Alternative 1: Applying a maximum inspection frequency of three years only to SWER lines and 22kV feeder lines

As discussed above, this alternative differs from the proposed regulations essentially in that it would limit the application of the maximum inspection frequency requirement to SWER lines and 22kV feeder

lines, rather than applying it to all above-ground assets in high bushfire risk areas. Electricity lines operated by the regulated parties are essentially of four kinds, as follows:

SWER Lines

These are common, and operate normally at 12,700 Volts. It is unusual, but not unknown that these lines would share poles with other voltages (usually low voltage).

22 kilovolt (22,000 volt) lines

These are also common, and operate normally at 22 kilovolts. Although most 22kV poles would not share with other voltages, sharing with low voltage or 66,000 Volt lines is not uncommon.

Low voltage lines

Outside townships, there are very few distributor-owned Low Voltage lines. These are lower risk than high-voltage lines, but are not risk free. Moreover, low voltage lines are commonly installed on the same poles as other voltages, usually 22 kilovolt lines^[1]

66 kilovolt (66,000 volt) lines These are sub-transmission lines and are the least common type. These 66kV lines commonly share poles with other voltages, usually with 22kV lines but sometimes with low voltage lines.

As is apparent from the above, the great majority of the relevant electricity lines are either 12,700 Volt SWER or 22,000 Volt lines, while the remaining lines are very often co-located on the same poles as on or other of these types of line. Moreover, the small proportion of Low Voltage and 66,000 Volt lines are geographically 'intermingled' with the 22kV and SWER infrastructure.

7.1.1. Expected benefits of the alternative

All above-ground electricity assets in high bushfire risk areas have the potential to cause bushfire ignition. However, as the VBRC recommendation recognises, the bulk of the ignition risk is caused by SWER lines and 22kV lines. This reflects two factors: that they are predominantly the kind of above ground assets found in high risk areas and the fact that higher voltage lines generally entail higher risk than lower voltage lines.

Given that there is some risk of both low voltage lines and 66kV lines causing bushfire ignition, the alternative of excluding these assets from the scope of the increased inspection requirements, as proposed by the VBRC, would necessarily entail a reduced level of benefits, vis-a-vis the proposed regulations. However, given the significantly lower risk entailed by low voltage lines and the limited

^[1] In rare cases they may share with 66 000 volt lines or, more rarely still, with both 22 000 and 66 000 lines (ie three voltages on one pole).

number of 66kV lines found in high risk areas, the difference in benefit levels between this alternative and the proposed regulations would, in practice, be small.

7.1.2. Expected costs of the alternative

The costs of this alternative would, in theory, be lower than those of the proposed regulations. The intention of the VBRC in making this specific recommendation was clearly to target its proposed increase in inspection requirements and avoid unnecessary cost increases. However, in assessing the comparative costs of this alternative and the proposed regulations, two considerations must be weighed.

Firstly, as indicated above, a relatively small proportion of the above ground electricity assets in high risk areas that would be captured by the proposed regulations are low voltage lines operated by MECs or specified operators or are 66kV lines. This means that the potential cost savings of avoiding increasing inspection frequencies for these assets would be low.

Second, it is unlikely, as a matter of practicality, that regulated parties would implement differentiated inspection arrangements for these assets were this alternative to be adopted. One reason for this is that, as indicated above, the low voltage/66kV assets are in many cases co-located (i.e. on the same poles) as the assets that would be subject to three-yearly inspection. Moreover, others that are not co-located are in any case geographically intermingled with the SWER/22kV assets. This means that it would be inefficient to inspect the two asset groups on a different cycle.

Particularly in the case of the major distribution businesses, the inspection procedure is well established and designed in such a way as to make the most efficient use of inspection resources. This includes the sequential inspection of poles on a 'run' that includes all poles in a geographic area based on either feeder or street/road. This is important not only from the inspection perspective, but also creates maintenance synergies and improves customer service by concentrating all work in an area at the same time, thus minimising lost time and reducing customer supply interruptions for work (although maintenance prioritisation may result in a number of visits over several months).

The two major distribution companies that would incur up to 90% of the costs of compliance with the proposed regulations both responded to a questionnaire from ESV by stating that their general approach to scheduling inspections would be to seek to schedule this activity in a way that was most efficient having regard to other commercial and managerial requirements. Hence, as discussed above, they expect to adopt a 30 month (2.5 year) inspection cycle, even though the regulations require only a 37 month cycle.

In this context, it is considered unlikely that the adoption of this alternative would yield any substantive reduction in inspection costs by comparison with the proposed regulations.

7.1.3. Assessment of the alternative

The above analysis indicates that, in practice, the benefits and costs associated with this alternative would be very similar to those of the proposed regulations. While expected benefits would necessarily be smaller, due to the more limited scope of the three-yearly inspection requirement under this alternative, the limited range of assets that would be excluded from the 3 yearly inspection requirement, plus the lower risk levels associated with low voltage lines, suggests that the difference would be small.

Similarly, while cost savings could potentially exist, their potential magnitude is also small, given the relatively small proportion of assets in question. More importantly, however, the commercial realities surrounding the inspection process imply that even these potential benefits would not be likely to be obtained in practice. The consequence is that this alternative would, in practice, be likely to entail very similar benefits and costs to those of the proposed regulations.

7.2. Alternative 2: Age-adjusted inspection frequency using 2.5 yearly inspection for assets 20 years and older and 5 yearly inspection for younger assets

Within the current context of substantial concern over the role of past inadequacies in inspection performance, it is arguable that the most appropriate variant of a risk-based inspection model would be one that seeks to improve effectiveness, rather than one which seeks to reduce costs. Consequently, the alternative assessed below is based on a combination of a more frequent inspection regime than the proposed regulations for older assets and a less frequent inspection for newer assets. Specifically, under this alternative, all assets that are less than 20 years old would be required to be inspected at five-yearly intervals, while older assets would be required to be inspected at 2.5 yearly intervals. In addition, all concrete poles would be required to be inspected at only five-yearly intervals.

7.2.1. Expected benefits of the alternative

As indicated above, the key benefit of this alternative is that it allows for a potentially more effective targeting of inspection activity. Evidence to the VBRC shows that there is a strong correlation between the age of an electricity line and the probability of it failing, particularly when the age of the assets in question exceeds about 40 years. This alternative would imply that fewer resources would be devoted to inspection of younger assets that had a comparatively very low probability of being found to be faulty and in danger of failure.

By implication, a larger quantum of resources could thereby be directed toward inspections of older assets characterised by higher fault rates. This implies that faults would be detected earlier, on average, than under the proposed regulations. Based on the intervals suggested above, the maximum time

elapsing between inspections of older assets would be seven months, or 19%, less than under the proposed regulations. This might mean, in many cases, that a re-inspection would occur prior to an additional bushfire season passing, rather than after it.

Similarly, distribution businesses have chosen, to date, to adopt lower inspection frequencies in relation to concrete poles because of observation of their superior reliability performance. This alternative would enable this approach to be continued, in contrast to the proposed regulations.

7.2.2. Expected costs of the alternative

Given the inspection frequencies proposed above, newer assets would be subject to inspection at intervals almost 40% less frequent than those required under the proposed regulations, as would concrete poles, even where they exceeded 20 years of age. Conversely, older assets would be inspected only 19% more frequently than under the proposed regulations.

The number of inspections required under this alternative, relative to the proposed regulations, cannot be estimated with any certainty, however, due to a lack of detailed data on the age profile of the affected assets and the number of concrete poles. An indicative estimate of the comparative cost implications of this alternative can, however, be derived by reference to a 2005 consultant's report on the asset age profile of Powercor assets, submitted to the VBRC³⁹. Based on the data contained in that report, it is estimated that 22% of high voltage overhead lines are less than 20 years of age, while the remaining 78% are at least 20 years old. Given the inspection frequencies required under this alternative, the percentage of assets that would need to be inspected each year to comply with this alternative is:

$$(78\%/2.5) + (22\%/5) = 31.2\% + 4.4\% = 35.6\%$$

By comparison, the percentage that would need to be inspected each year under the proposed regulations is:

$$100\% \times (12/37) = 32.4\%$$

This comparison suggests that this alternative could yield *total* inspection costs that were

$$(35.6 - 32.4)/32.4 = 9.9\%$$

higher than those associated with the proposed regulations. To convert this percentage into dollar terms, it must be compared with the *total* inspection costs that would be incurred under the proposed

³⁹ Exhibit 578 – SKM Powercor and Citipower Age Opex Report – *Impact of Ageing Assets on Operating Expenses- Final Report* (February 2005), p 14. It has been assumed that half of the assets identified as being between 15 and 24 years of age in 2010 would be classified as being less than 20 years of age for inspection purposes.

regulations. As noted in Tables 5.7 and 5.8, the total incremental costs (i.e. compared with a "business as usual" base case) of inspections and associated monitoring activity in accordance with the proposed regulations is estimated at approximately \$3.5 million per annum⁴⁰. To this must be added the business as usual costs, estimated at \$8.9 million. Thus, the total annual costs of inspections and related activity under the proposed regulations is:

$$(\$3,591,249 + \$8,861,700) = \$12,452,949$$

The total costs of this alternative have been estimated above to be 9.9% higher than the total cost of the inspection related provisions of the regulations. This is equal to:

$$\$12,452,949 \times 1.099 = \$13,685,791.$$

The incremental costs of this alternative are therefore given by the difference between these total costs and the total "business as usual" costs of inspection-related activities set out in Section 5, which are \$8,861,700. The incremental cost associated with this alternative is therefore:

$$\$13,685,791 - \$8,861,700 = \$4,824,091 \text{ per annum.}$$

This is equal to \$40.1 million in present value terms over 10 years.

The annual incremental cost of \$4.8 million can be compared with the incremental cost of \$3.6 million calculated for the proposed regulations. Thus, option 2 would be likely to yield annual costs \$1.2 million higher than those associated with the proposed regulations.

Minimum compliance vs actual reported behaviour

However, this estimate is based on a comparison of the costs that would be incurred by companies that were "minimally compliant" under each of the two options. By contrast, consistent with the intentions set out in the questionnaire responses received in 2011, the two distribution businesses that account for by far the majority of high-risk assets currently adopt a 2.5 year inspection cycle in response to the proposed regulations. Thus, there would be no difference between the costs currently being incurred by this group in respect of their older assets under the two alternatives. By contrast, they would incur lower costs in respect of their younger assets under this alternative, inspecting 20% of their sub-20 year aged assets annually under this alternative, rather than 32.4%, as under the proposed regulations.

⁴⁰ The following calculations effectively assume that the 9.9% increase in inspection activity calculated to be associated with this option would increase all of the inspection-related costs enumerated in Tables 5.7 and 5.8 by this percentage. For example, the incremental costs associated with the qualifications requirements of the proposed regulations are increased by this amount. This reflects the fact that higher levels of inspection activity would increase resource requirements in respect of inspectors, thus likely increasing training costs. While some costs may increase less than proportionately with the quantum of inspection activity, this is considered the most appropriate simplifying assumption, given that all the identifiable costs can be expected to vary to some degree with the quantum of inspections undertaken.

From the point of view of an asset owner in this position, and taking into account the actual use of a 2.5 year inspection cycle, if the age profile of the affected assets is as per the above calculations the total proportion of assets inspected under this alternative of 35.6% (as above) compares with an implicit inspection percentage under the proposed regulations of 40%. This implies that this alternative could actually result in costs around 10% lower than under the proposed regulations.

The above analysis indicates that, while a notional calculation of the extent of works required to achieve compliance under the two alternatives (i.e. in terms of percentage of assets to be inspected) suggests that costs would be almost 10% higher under this alternative, an alternative approach which takes into account the current practices of affected parties in relation to compliance with the existing regulations suggests that this alternative could actually be implemented at a 10% *lower* cost.

There is clearly a conceptual issue to be resolved in terms of determining the appropriate cost estimate to be employed. While cost estimates based on the current practices of the affected parties should *a priori* be preferred, it must be recognised that changes in business practices and processes could mean that the currently indicated approach to implementing the proposed regulations is not ultimately adopted in practice - or is initially adopted but later revised.

In sum, it can be said that the costs of this alternative would be broadly similar to those associated with the proposed regulations, with uncertainty existing as to the direction of any (minor) difference in costs.

7.2.3. Assessment of the alternative

While this alternative is based on logical principles, experience to date indicates that a number of practical difficulties would be associated with it, while the expected benefits, in terms of ensuring similar levels of safety performance at lower cost in terms of asset inspections, are likely to be small or non-existent.

The previous asset inspection practice (originating from the SECV) was that poles were not inspected for the first inspection cycle. That is, where a five-year inspection cycle was adopted, a new pole will not be inspected until it reaches ten years of age. Hence, an element of the approach proposed under this alternative is already in place. However, experience shows that the gains from adopting this "exemption" process are small, as the new asset is contiguous with other, older assets in many or most cases. This means that the inspector is already on site, and the only saving is the actual inspection time, amounting to 10-15 minutes at most per pole. Thus, it is only where an entire line has been replaced that the adoption of the longer inspection cycle would lead to substantial savings.

A practical difficulty has also been identified in implementing this alternative in practice. This is that the 'age' of an asset is, in many cases, hard to define. Thus, a cross-arm may frequently be replaced on an old pole. In such circumstances, the question is open as to whether this constitutes a "new" or an "old" asset and, thus, what inspection frequency should be adopted. Even if the view is taken that the asset

is "new" in this situation (which may be appropriate given that pole failures are rare, compared to the incidence of fires due to the pole top equipment failing) the question of whether partial replacement of pole-top equipment would be enough to cause an asset to be reclassified as new.

Moreover, while the proposed different inspection cycles for concrete vs. wood poles can be justified on the basis that timber poles are subject to rot, while concrete poles are not, it can be noted that the rate of deterioration of conductors, ties, insulators and other pole-top hardware is unaffected by pole type. Hence, given that most failures relate to pole-top equipment, there is arguably little risk-based rationale for adopting differential inspection frequencies based on pole type.

7.3. Alternative 3: Age-adjusted inspection frequency using a 37 monthly inspection for assets 20 years and older and 5 yearly inspection for younger assets

This alternative would employ a 37 month maximum inspection frequency for electricity assets 20 years and older, in common with the proposed regulations, but would adopt a five yearly inspection frequency for assets younger than 20 years, in common with alternative 1, above.

7.3.1. Expected benefits of the alternative

The benefits of this alternative can be expected to be broadly similar to those of the proposed regulations. As noted, around 78% of the electricity assets affected by the proposed regulations are believed to be at least 20 years old. The inspection requirements applicable to these assets would be identical under the proposed regulations and this alternative.

Conversely, inspections for the remaining 22% of assets would occur at five yearly intervals, rather than 37 month intervals as under the proposed regulations. Since inspections would occur almost 40% less frequently, it can be expected a priori that faults would be approximately 40% less likely to be detected prior to an asset failure occurring. However, given the expert evidence cited above to the effect that asset failure rates increase rapidly with asset age for older assets, it can be inferred that only a very small proportion of overall faults detected and remedied as a result of asset inspections relate to assets younger than 20 years. To the extent that this is the case, the reduction in benefits under this alternative, vis-a-vis the proposed regulations, can also be expected to be very small.

However, given the lack of specific quantitative information on the relationship between asset age and fault rates, it is not possible to provide a quantitative estimate of this reduction in benefits.

7.3.2. Expected costs of the alternative

As noted, assets less than 20 years old would, under this alternative, be inspected on a five-yearly basis, rather than a three yearly basis. The proportion of assets required to be inspected annually under the proposed regulations was estimated above as:

$$100\% \times (12/37) = 32.4\%$$

By contrast, the proportion of assets that would need to be inspected annually under this alternative is:

$$78\% \times (12/37) + 22\% \times (1/5) = 25.3\% + 4.4\% = 29.7\%$$

Thus, the number of inspections to be carried out would be $2.7\%/32.4\% = 8.3\%$ lower than under the proposed regulations. On the assumptions used above in respect of option 2 - i.e. that all inspection-related costs will vary proportionately with the number of inspections undertaken - this suggests that the total costs of option 3 would be 8.3% lower than those of the proposed regulations.

The total costs of the proposed regulations were estimated above as being \$12,452,949 per annum. Thus, the costs of option 3 can be estimated as:

$$\$12,452,949 \times 0.917 = \$11,419,354$$

The incremental costs of Option 3, compared with the business as usual base case, are therefore:

$$\$11,419,354 - \$8,861,700 = \$2,557,654$$

This is approximately \$1.0 million less than the estimated \$3.6 million incremental cost of the proposed regulations.

The annual incremental cost of Option 3 is equal to \$21.3 million in present value terms over 10 years.

7.3.3. Assessment of the alternative

As noted above, inspection costs are expected to be somewhat lower under this alternative than under the proposed regulations. On the basis of the above calculations, total costs would be around \$1.0 million annually lower than under the proposed regulations. In practice, however, the difference in costs between the proposed regulations and this option may be somewhat lower. This will be the case to the extent that there are problems in determining the age of certain assets. Moreover, as suggested above, where younger and older assets are found together (e.g. due to ad hoc past replacements of assets) inspection costs are not likely to be reduced in proportion to the number of inspections being undertaken.

The benefits of this alternative will, logically, necessarily be lower than under the proposed regulations. However, the extent of this reduction in benefits is expected to be small, since only a small proportion of asset faults is expected to occur in assets that are less than 20 years old, while the number of faults occurring within this asset group - and hence the additional number of undetected faults causing ignition under this option - will consequently be small.

Given the logic of inspection targeting and the fact that there is a high degree of confidence, based on expert testimony to the VBRC and submitted documents, that asset age is well-correlated with fault probability and is thus a sound basis for targeting activity, it must be assumed that the balance of benefits and costs will be more favourable under this alternative than under the proposed regulations. However, the above suggests that the size of any incremental gain in this regard will be small.

Conversely, it can be noted that this alternative does not fully implement the relevant recommendations of the VBRC and is therefore inconsistent to some degree with the commitments given by all major political parties to implement these recommendations.

7.4. Alternative 4: improve inspection quality without mandating inspection frequency

A fourth feasible alternative would involve acting to introduce qualifications requirements for inspectors in order to enhance the effectiveness of inspections, while still allowing asset owners to determine their own inspection frequencies. The proposed inspection frequencies would, as is current practice, need to be approved by ESV in the context of the broader BMP submitted for approval under the Act's requirements. This could mean that ESV could administratively require an increase from the current five year inspection cycle in some cases, but an increase in frequency to three years would not be mandated via the regulations themselves under this alternative.

7.4.1. Expected benefits of the alternative

This alternative would be expected to lead to a substantial reduction in in-service failures of electricity assets. As noted elsewhere, a 1997 report commissioned by PowerCor and cited by the VBRC found that if a set of improvements in inspection effectiveness then being foreshadowed were implemented, expected reductions in in-service failures would fall by over 80 per cent from then observed levels. This anticipated reduction was even larger than that modelled in respect of a notional increase in the frequency of inspections from five yearly to three yearly.

These results imply that a very substantial proportion of the benefits of the proposed regulations would be expected to be obtained under this alternative, even though the frequency of inspections would not necessarily increase.

An additional benefit of this alternative is that it avoid departing from the generally performance-oriented basis of the current legislative structure, under which asset owners are made clearly responsible for determining an overall management strategy for minimising the bushfire risk associated with their assets. That is, it avoids adding a prescriptive element to the regulations, in contrast to the position taken since 2010, under which the minimum inspection frequency has been specified in the regulations. This can be considered appropriate given the fact that the risk associated with particular assets necessarily with asset age and other characteristics and with the level of risk of the environment in which the assets are located. Providing for a flexible inspection frequency recognises this difference in risk profile.

7.4.2. Expected costs of the alternative

The costs of this alternative can be expected to be somewhat lower than those associated with the proposed regulations. As set out in Section 5, above, the costs of increasing the inspection frequency constitute the majority of the costs associated with the proposed regulations, with the costs specifically attributed to the imposition of qualifications requirements for inspectors being estimated at only around \$1.1 million per annum.

This implies that, were the same approach to upgrading the effectiveness of inspections to be taken as under the proposed regulations, without any increase in inspection frequency being required, the incremental costs of this alternative would be around \$1.1 million per annum, or \$9.1 million in present value terms over 10 years.

In practice, however, the costs associated with this alternative would be likely to be larger than this estimate would suggest, for two reasons. First, in the absence of an increase in inspection frequency, the greater reliance on improved inspection effectiveness that is necessarily implied would be likely to result in a farther-reaching approach to improving the effectiveness of inspections than that currently adopted. This could involve, for example, mandating a more rigorous qualification requirement than that currently proposed or mandating some aspects of the inspection process.

Second, while this alternative does not imply any mandated inspection frequency, the context in which it would be implemented is one in which the events of Black Saturday had already given rise to the VBRC recommendation to mandate a maximum three year frequency and this recommendation had already been in place for almost three years. Thus, were the use of a mandated inspection frequency to be abandoned, as adoption of this option would imply, it is reasonable to assume that the ESV would use its discretion over acceptance of proposed BMP to require, in practice, that more frequent inspections than had been typically undertaken prior to Black Saturday would be implemented.

To the extent that this approach was taken, the costs of this alternative would be higher than suggested above and, in the limiting case, could approach those implied by the adoption of the proposed regulations.

7.4.3. Assessment of the alternative

At first glance, this alternative would entail lower costs than those associated with the proposed regulations, since the major cost driver of the proposed regulations would not be present under this alternative. However, as discussed above, the cost reduction involved would be limited by other factors.

The benefits of this alternative would also be lower than those of the proposed regulations. While increased inspection effectiveness is believed to be able to reduce in-service failure rates substantially, the significantly greater time elapsing between inspections under this alternative - potentially remaining at five years versus 2.5 to 3 years under the proposed regulations - necessarily means that there is greater opportunity for failures to occur.

In addition, this alternative does not respond to VBRC recommendation 28 and is inconsistent with the Government's commitment to adopt and act on all of the Commission's recommendations. It would also involve abandoning, after less than three years, the 37 month maximum inspection cycle requirement of the current regulations. Given that the relevant distribution businesses have indicated their general acceptance of these requirements, as discussed above, the rationale for such an approach would be difficult to establish.

8. Conclusion

8.1. Overview and break-even analysis

The proposed regulations are expected to have essentially identical cost implications to those of the existing regulations, which have been in force since 2010, and which the proposed regulations will replace. The substantial majority of these costs relate to the specific inspection requirements in relation to at risk electricity assets. The costs of the proposed regulations have been assessed as constituting to an increase of around \$3.6 million per annum, or 40%, in the costs that major electricity companies and specified operators would incur under a "business as usual" (BAU) scenario, in which no regulations were made, but the relevant provisions of the Electricity Safety Act 1998 continued in force. These incremental costs of \$3.6 million per annum are equivalent to around \$29.9 million in present value terms over the expected 10 year life of the proposed regulations .

While the incremental costs of the proposed inspection requirements are significant in relation to the BAU base case, they are very small in relation to the turnover of the businesses concerned. The revenue of the two largest distribution businesses alone is of the order of \$1.5 billion per annum, while profits exceeded \$300 million⁴¹. That said, it must be acknowledged that, while the regulated entities initially bear the cost of the improvements inspection arrangements required by the regulations, it is likely that most of these costs will be passed on to consumers of electricity through the periodic regulated electricity price resetting arrangements.

The expected benefits of the proposal involve reductions in the risk of losses due to bushfires caused by electricity assets. These benefits are expected to be obtained due to substantially improved inspection arrangements allowing for significant improvements in the allocation of maintenance expenditures on electricity lines in high bushfire risk areas; while the major distribution businesses expect some expenditures to be brought forward, they do not anticipate that maintenance expenditure over the medium term will be affected by the changes.

A total of four alternatives to the proposed regulations have been identified and analysed. Given that the preponderance of the costs of the proposed regulations are related to the prescriptive inspection requirements they impose, the identified alternatives are focused on this aspect of the regulations. The four alternatives essentially differ in terms of the question of whether a minimum inspection frequency is imposed and, if so, what that frequency should be and whether it should differ according to the age of the electricity assets being inspected. Table 8.1, below, summarises the cost implications of the proposed regulations and the four alternatives analysed. As discussed in Section 7, there are significant uncertainties as to the costs of some alternatives, both due to the potential to take different conceptual

⁴¹ Derived from the latest Annual Reports for Powercor and SP AusNet.

approaches and due to the difficulty of determining the likely practical impact of some aspects of the alternatives. As a result, the costs of some alternatives are presented in terms of a range in the table.

Table 8.1: Comparative cost estimates of the identified options

	BAU	Incremental ⁴²	Incremental (%)	PV (10 years) of Incremental costs	Total annual costs	BEA - required % reduction in bushfire cost
Proposed Regulations	\$8,861,700	\$3,591,249	40.5%	\$29.9 million	\$12,452,949	6.0%
Alternative 1	\$8,861,700	≈ \$3,591,249	≈ 40.5%	≈ \$29.9 million	≈ \$12,452,949	6.0%
Alternative 2	\$8,861,700	\$3,208,283 - \$4,824,091	36.2% - 54.1%	\$26.7 - \$40.1 million	\$11,981,506 - \$13,685,791	5.3% - 8.0%
Alternative 3	\$8,861,700	> \$2,557,654	28.6%	> \$21.3 million	\$11,419,354	> 4.3%
Alternative 4	\$8,861,700	> \$1,098,800	12.4%	> \$9.1 million	\$9,960,500	>1.8%

A fundamental point to be made in relation to the cost calculations summarised in Table 8.1 is that the BAU costs identified in the table relate to the period prior to, and in the immediate aftermath of the Black Saturday fires. In practice, it is likely that the distribution businesses would have increased the resources devoted to inspection activity following Black Saturday, even in the absence of any regulatory change. Such a move would be a likely response to a probable reassessment of the risks they face, given the consequences of Black Saturday, the role of electricity asset failure and the costs arising from successful class actions by affected parties. The need to regain public confidence is also an intangible factor that would have been likely to contribute to an increase in BAU costs in this context. To the extent that this is so, the incremental costs estimated in respect of all of the above options can be considered to be an over-estimate of the true position.

Table 8.1 shows that alternative 4, involving specifying qualifications requirements but no minimum inspection frequency, would be the least cost option. However, incremental costs are likely to be greater than the notional \$1.1 million per annum cited for a number of related reasons. As suggested above, some increase in inspection frequency would be likely even in the absence of a regulatory requirement. Second, it is plausible that DBs would choose to increase qualifications standards by a greater amount than that modelled, as an alternative to implementing a 37 month inspection frequency.

⁴² Incremental cost figures include the cost of preparing and submitting BMP, as well as the costs to ESV of assessing and accepting draft BMP. As discussed in Section 5, these costs represent a very small proportion of the total incremental costs of the regulations, with annual costs to MECs/SOs being estimated at around \$30,000 and similar annual costs being incurred by ESV.

Alternative 3 is assessed as the next lowest cost alternative, with incremental costs of around \$2.5 million per annum, equal to around a 28.6% increase on BAU costs. However, it is also likely that the true costs of this alternative could be higher than this "best estimate" would suggest. This would be so to the extent that the practicalities of inspecting assets in a context in which older and younger assets were often intermingled and the age of some assets is difficult to determine mean that the notional cost savings associated with having differential inspection frequencies, based on asset age, are unable to be captured in practice.

The cost estimate provided for Alternative 2 is, in fact, a range. This reflects a conceptual issue of determining whether the appropriate costing for use is one that reflects minimum compliance with the regulations or the actual approach currently taken by DBs. If the latter view is taken, this alternative involves slightly lower costs than the proposed regulations, while the costs involved would be higher than the proposed regulations if the former view is taken.

Finally, it has not been possible to distinguish meaningfully between the costs imposed under the proposed regulations and under Option 1. This reflects the fact that there is substantial doubt as to whether it would be feasible to adopt two different inspection cycles along the lines this option proposes (and which was proposed by the VBRC). Hence, while Option 1 notionally offers the possibility of lower inspection costs than the proposed regulations, it is likely that there would be little difference in practice.

In sum, the proposed regulations and the four options were developed on the basis of the recommendations of the VBRC and the principles of good regulatory practice, particularly in relation to risk based inspection activity. However, the analysis provided shows that they differ to a relatively limited extent in terms of the costs that they would be likely to impose in practice.

The expected benefits of the various options are also subject to significant uncertainty. The causes of this uncertainty are several, and include future changes to bushfire risk in the context of changing weather patterns, the impact of the ageing of the electricity infrastructure on its contribution to bushfire risk and the effectiveness of improved inspection arrangements in mitigating these risks. Given these uncertainties, it has been necessary to conduct a break-even analysis rather than a formal benefit/cost analysis.

The results of the break-even analysis are presented above in Table 8.1. It shows that the regulations will produce net benefits if losses due to bushfires caused by electricity assets are reduced by more than 6.0%. Option 1 would similarly require a 6.0% reduction in bushfire losses to achieve a positive present value, while the required percentage reduction for option 2 is in the range 5.3% - 8.0%. For Option 3 the required reduction is greater than 4.3%, while for Option 4 it is greater than 1.8%.

In assessing the likelihood that these threshold levels of benefits will be reached, the size of the expected impact of the regulations on current inspection activity must be considered. In respect of the major electricity distribution businesses with assets in bushfire prone areas, it is anticipated that the

current level of inspection activity will be approximately doubled. It can be considered highly likely that such a substantial increase in inspection activity, combined with the expected improvement in inspection quality, deriving from the requirement to use only qualified inspectors, will yield important benefits in terms of the design and implementation of the resulting maintenance programs.

Evidence on this question was presented to the VBRC. The Commission cited a 1997 study of the Powercor network which found that a reduction in the inspection interval from five years to three years would be expected to result in a 70 per cent reduction in in-service failures. The same study found that:

"...a substantial improvement in the effectiveness of asset inspection significantly reduces the risk of in-service asset failure. Powercor's analysis shows that, if the improvements in effectiveness foreshadowed in 1997 had been made without extending the inspection cycle, the projected number of in-service failures each year would have reduced from 500 to 84."⁴³

This evidence suggests that each of the two main substantive changes incorporated in the proposed regulations would, in isolation, be expected to reduce in-service failures by more than two thirds. The combination of these measures must be expected to have a still larger impact. Such a major reduction in the incidence of in-service failures must *ipso facto* be expected to result in a substantially reduced risk of bushfire ignition. In turn, the expected extent of bushfire-related costs due to ignition by electricity assets must be expected to be sharply reduced.

If, by contrast, a 25% reduction in these costs were to be achieved, net benefits averaging around \$20 million per annum would be obtained. Even this level of benefit might be considered to be conservative given the size of the expected reductions in in-service failures highlighted in the above report to Powercor.

In this light, it is considered highly likely that the threshold levels of benefits will be reached in practice and that most or all of the options analysed would, consequently, yield positive net benefits. It should be noted, in this context, that the major elements of the proposed regulations are consistent with the specific recommendations of the VBRC. These recommendations arose as a response to the significant evidence presented to the Commission that there were numerous instances of inspections failing to uncover asset faults and that inspection frequencies were in often insufficient to allow faults to be reliably rectified before failure occurred. Thus, steps taken to remedy both of these identified concerns can be expected to have substantial performance impacts.

A significant risk, in relation to the above, arises from the information received from one major distribution business that stated that there was currently no correlation between the time elapsed since last inspection and the probability of the asset failing. This was presented as evidence that the current inspection arrangements are effective and that no improvements are required. However, even if this conclusion is robust, the ageing of the electricity infrastructure must be taken into account. As noted

⁴³ Victorian Bushfire Royal Commission (2010). *Final Report*. Vol. 2, Ch 4., p 160.

above, much of that infrastructure is now approaching an age at which failure rates can be expected to increase very rapidly. Within this context, a significant improvement in inspection arrangements is very likely to yield significant benefits over the medium term.

The break-even analysis, being based on expected values, implicitly regards the population as being risk-neutral in relation to bushfire risk. However, the response to the Black Saturday fires, as documented by the VBRC, strongly suggests that the Victorian population is, in fact, risk averse in respect of bushfire risk. Indeed, the experience of previous major bushfires and the inquiries conducted in respect of them suggests that this risk averse view has existed for some time. This consciousness of a strong community expectation that strong action will be taken to reduce the future risk of catastrophic bushfires underlies the extensive recommendations of the VBRC report, including those that specifically call for the major substantive elements of the proposed regulations to be adopted.

The effect of adopting an assumption of risk aversion here is to reduce the threshold level of benefits that must be met in order to achieve a break-even outcome. That is, a risk averse population will theoretically be willing to spend on reducing the risk of bushfires up to a level that actually exceeds the expected value of the cost of losses due to bushfires. This implies that the break-even level of reduction in bushfire related losses will be lower than the percentages indicated above would suggest. However, in the absence of any specific information on the degree of risk aversion involved, a precise "risk preference adjusted" break-even point cannot be calculated. It can simply be noted that, to the extent that this notional adjusted break-even point is lower than that identified above, the likelihood that the proposed regulations will reduce bushfire related costs to a level that meets this threshold is necessarily increased.

It is also important to note the final incidence of the costs involved. To the extent that the DBs are able to make the case that they have incurred an increase in their costs as a result of the regulated inspection requirements, it is open to them to request that this increase be taken into account by the economic regulator (i.e. the Australian Energy Regulator) in the context of its price re-set decisions. This means, in effect, that the community, as electricity users, would ultimately bear a substantial proportion of the costs in this case. This is the necessary implication of the model of price regulation adopted in respect of the electricity industry.

Base case for the BEA calculations

The above discussion of the break-even percentage reductions in fire risk for the various options have been calculated effectively uses a base case which reflects the actual practices of the MECs and SOs as they stood prior to both Black Saturday and the introduction of the interim regulations in 2010. However, given the experience of Black Saturday and the several successful class actions taken against distribution businesses since that time, it is clearly likely that the distribution businesses would have changed their "Business As Usual" practices in recent years, even in the absence of regulatory change.

Acknowledgement of this reality has two distinct implications for the conduct of break-even analysis. First, to the extent that the level of activity undertaken under the BAU scenario increased following Black Saturday, the incremental costs of the proposed regulations would be reduced, vis-a-vis the calculations set out in the preceding sections. This, in turn, implies that the percentage reduction in bushfire ignitions required in order to yield a positive net benefit would also be reduced.

However, the second implication of an increase in BAU activity is that the scope for further improvements in terms of reduced bushfire ignition due to the adoption of the proposed regulations would also be reduced. That is, the probable percentage reduction in fire starts as a result of the adoption of the proposed regulations would be lower under such a scenario.

In practice, while it is acknowledged that DBs, in particular, may well have implemented significant changes to their practices in the absence of regulatory change, it has been considered preferable for analytical purposes to adopt a base case consistent with their previous practice. This reflects both:

- uncertainty as to the likely extent of such changes in BAU practices and consequent difficulty in developing a robust, alternative base case; and
- the benefit of highlighting the extent of the changes in inspection arrangements that will occur *against the background of actual historical practice.*

Impact of intangible benefits

The BEA is, of necessity, implicitly predicated on an assumption of a risk neutral population. Alternatively put, it calculates a break-even point based on setting the quantified costs of the proposed regulations against the tangible benefits of the mitigation of bushfire risks arising from the use of electricity assets. However, given the capacity for disastrous outcomes to result from the ignition of bushfires as a result of electricity asset failures - as demonstrated clearly on Black Saturday - there are important intangible benefits attached to the adoption of the proposed regulations.

Specifically, these arise in the form of enhanced public confidence that the general duties established in the Act - i.e. to minimise risks arising from the use of electricity assets - are being appropriately complied with by MECs and SOs and that adequate regulatory oversight is being exercised. While it is clear that there are significant commercial disciplines operating on these groups, these essentially self-regulatory mechanisms are widely considered (including by the VBRC) as being insufficient in a context in which the potential for disastrous outcomes exist.

8.2. Multi-criteria analysis

As discussed above, it is not possible to compare the proposed regulations and the identified alternatives in fully quantified terms, chiefly because of necessary uncertainty as to both the costs associated with the alternatives and, in particular, the benefits associated with all four alternatives. Consequently, in accordance with the Victorian Guide to Regulation, a Multi-Criteria Analysis (MCA) has

been undertaken. MCA is a tool which allows different alternatives to be assessed simultaneously in terms of multiple criteria. It is particularly widely used where it is not possible to quantify all impacts and/or to express them in dollar terms.

Three criteria have been identified, consistent with the underlying objectives of the proposed regulations. These are:

- The ability of the proposal to reduce bushfire risks arising from electricity asset failure;
- The substantive compliance costs of implementing the proposal; and
- The administrative burdens imposed by the proposal.

Thus, the first, of these criteria relates to the benefits attributable to the various alternatives, while the second and third relate to the costs they would impose. Given that there are two cost criteria and one benefit criterion, it is necessary to weight the criteria in order to provide a balanced assessment. This means that the total weight given to the two cost criteria must equal that of the benefit criterion. Substantive compliance costs are, where quantifiable, generally found to be significantly larger than administrative burdens. Hence, the substantive criterion has been weighted significantly more heavily than the administrative costs criterion.

Consistent with the above considerations, the following weights have been assigned to the criteria:

- Ability to reduce bushfire risks: 1.0
- Substantive compliance costs: 0.8
- Administrative burdens: 0.2

The following discusses the scores accorded to each alternative in relation to each of the criteria. Each alternative is assessed against a base case of the principal regulations continuing in force as they were prior to the adoption of the interim regulations. Scores are allocated against a scale ranging from + 10 to - 10, with a zero score being equivalent to the situation obtaining in the base case.

Ability to reduce bushfire risks

As discussed above, the proposed regulations are considered likely to be highly effective in improving the timely detection of faults and minimising in-service failures, relative to the current position. They have therefore been allocated a score of +8 against this criterion. Alternative 1, involving applying the maximum inspection frequency requirements only to SWER and 22kV lines, as recommended by the VBRC, has been assessed as marginally less effective in this regard than the proposed regulations. Consequently, it has been scored at + 7.

Alternative 2, involving adopting variable inspection frequencies, based on a 2.5 year/5 year inspection schedule has the theoretical potential to yield still greater effectiveness, by focusing inspection effort

more closely on older assets likely to be more failure prone. However, as noted above, it is expected that the *actual* inspection frequency for assets over 20 years of age that would be adopted by the major distribution businesses under the proposed regulations would also be 2.5 years, as with the proposed regulations. Thus, the practical difference between the proposed regulations and this alternative would apply only to the small proportion of at risk electricity assets operated by specified operators. Given this, the expected difference in effectiveness, vis-a-vis the proposed regulations is again small. Hence it scores + 9 on this criterion.

Alternative 3, adopting variable inspection frequencies based on a 37 month/5 year inspection schedule, was assessed as entailing a lower degree of effectiveness than the proposed regulations. However, given the small difference between the two alternatives in this regard, this alternative scores + 7 points on this criterion.

Alternative 4, of setting minimum qualification requirements for inspectors without specifying a minimum inspection frequency is expected to yield significant effectiveness gains by comparison with the base case, but to be somewhat less effective than the proposed regulations. Consequently, this alternative scores + 4 against this criterion.

Substantive Compliance Costs

All four alternatives increase substantive compliance costs when compared with the status quo and therefore receive negative scores. The least costly alternative is Alternative 4, involving setting minimum qualifications requirements only. This alternative therefore scores -2.

The proposed regulations are likely to be significantly more costly than this alternative, given current asset inspection practices - as noted in Table 8.1, the increased inspection frequency alone is likely to increase inspection-related costs by almost 40%. They therefore score - 6.

Alternative 1, involving limiting the application of the minimum inspection frequency requirement to SWER and 22kV lines only has been assessed as having virtually identical implications for substantive compliance costs and also scores - 6.

Alternative 3, involving adopting variable inspection frequencies based on a 37 month/5 year inspection schedule was found to entail incremental costs almost one third lower than those of the proposed regulations. This alternative therefore scores - 4. Alternative 2, involving adopting variable inspection frequencies based on a 2.5 year/5 year inspection schedule, was found to have the highest incremental costs, being \$1.2 million higher than those of the proposed regulations, and score lowest with - 7 points.

Administrative Burden

This criterion focuses on the administrative burdens placed on both regulated parties and on the regulator under each alternative. These burdens constitute the resources required to interpret and

apply the requirements of each option in practice. The proposed regulations score highest against this criterion, since both the minimum inspection frequency and the qualifications requirements are established explicitly in the regulations, while the same inspection frequency applies to all at risk assets. The fact that these matters are specified explicitly means that administration of the regulations should be less costly and that there should be greater certainty of outcome than under the current regulations.

From the point of view of regulated parties, there is no requirement to determine an appropriate inspection schedule for the relevant assets, or to determine whether differentiated inspection frequencies should be adopted for different asset types. Such judgements, if required, must be made in the context of the broader set of strategies and mechanisms established under the BMP and must also take account of commercial requirements. Hence, this is potentially a relatively complex task. From the point of view of the regulator, there is similarly no requirement to make judgements about the acceptability of a proposed inspection frequency in the context of the specific BMP proposal and asset profile.

Given these factors, the proposed regulations receive a positive score, assessed as + 4. The alternative of setting a maximum inspection frequency only for SWER and 22kV lines receives the same score. While it would theoretically be necessary for operators to identify appropriate inspection frequencies for low voltage and 66kV lines under this alternative, the above discussion indicates that, in practice, they could be expected to adopt the same inspection frequency for all assets.

The alternative of specifying only a minimum qualification requirement is considered to have a similar degree of ease of administration to the current arrangements, since it does not entail a need to verify that a prescribed asset inspection frequency has been met and limited verification in relation to the qualification requirement is expected to be required. It therefore scores zero.

The alternative of variable inspection frequencies is considered to impose greater administrative difficulties than the previous regulatory requirements, as discussed in section 7. In particular, it potentially requires verification of the age of a range of assets and raises the issue of the treatment of various assets where partial renewal of the asset has previously occurred (e.g. replacement of pole-top equipment on an existing pole). This difficulty arises in respect of both of the alternatives based on variable inspection frequencies. While regulated parties have made some distinctions between asset types in setting inspection frequencies under current arrangements (e.g. inspecting concrete poles less frequently than wooden poles), it is clear that adopting an alternative based on asset age-based variations in inspection frequencies would be more administratively complex than under these "base case" arrangements.

The extent of this increase in complexity is difficult to verify. Hence, this alternative has been given a only a small negative score, suggesting a small degree of additional administrative burden. It is considered, however, that this is a conservative approach, given some of the above discussion of the difficulties of judging the ages of some assets that have been partially renewed. Hence, it is possible that this alternative should receive a lower score against this criterion.

Hence, both of the alternatives based on variable inspection frequencies must receive a negative score. Both alternatives have been assessed as scoring - 2.

Table 8.2: Multi-criteria analysis of feasible alternatives

	Proposed regulations	Alternative 1: Limit 3 yr inspection requirement to SWER & 22kV lines	Alternative 2: Variable inspection frequencies (2.5 yr/5 yr)	Alternative 3: Variable inspection frequencies (37 month/5 yr)	Alternative 4: Qualifications regulated only
Reduction in bushfire risk	+8 x 1 = + 8	+7 x 1 = + 7	+9 x 1 = + 9	+ 7 x 1 = +7	+ 4 x 1 = + 4
Substantive compliance cost	- 6 x .8 = -4.8	- 6 x .8 = -4.8	- 7 x .8 = -5.6	- 4 x .8 = - 3.2	- 2 x .8 = - 1.6
Administrative burden	+ 4 x .2 = +.8	+4 x .2 = +.8	-2 x .2 = - .4	- 2 x .2 = - .4	0
Total	+ 4.0	+ 3.0	+ 3.0	+ 3.4	+ 2.4

Table 8.2 shows that all of the options considered received positive scores. This implies that all are preferred to the base case of not proceeding to replace the current regulations at the time of their sunseting. The scores received by the five options are also relatively similar, ranging from a low of 2.4 to a high of 4.0, indicating that the practical differences between them are relatively small. This result, in which three alternatives in particular all receive very similar scores, reflects the fact that despite being formally quite distinct, consultation with regulated parties and observation of past practice has demonstrated that the actual response to these three alternatives would be very similar. Thus, for example, three alternatives (the proposed regulations and options 1 and 2) were all rated identically in terms of substantive compliance cost, because it is expected that the inspection arrangements that would be adopted in response to each alternative would be essentially identical.

The proposed regulations score highest, with 4.0 points. This reflects the fact that they receive the joint highest score in relation to compliance costs and administrative burdens, while receiving the second highest score on the reduction of bushfire risk criterion. Option 2, involving variable inspection frequencies, with a 2.5 year frequency for older assets and a 5 year frequency for those younger than 20 year, scores next highest with 3.8 points. This option scores highest on the criterion of reduction in bushfire risk, but scores poorly in relation to administrative burdens.

However, a difficulty in respect of the above analysis must be acknowledged. It has been assumed implicitly that, in the absence of regulations explicitly requiring a set 37 month maximum inspection cycle and specified qualifications criteria for inspectors, ESV practice in assessing and approving proposed BMP would be unchanged from the situation that obtained prior to 2009. In practice, this is

highly unlikely. The combination of community expectation and the government's commitment to implementing the VBRC recommendations, including those relating to the frequency and quality of asset inspections, implies strongly that, even in the absence of explicit regulatory requirements, there would be significant pressure on ESV to do all that it could within the existing statutory framework to require the affected bodies to implement improved inspection practices. To the extent that changes to current arrangements are considered likely to follow due to these dynamics, it is clear that the above will tend to over-estimate both the benefits and the costs of the proposed regulations.

Finally, the current regulatory context must be acknowledged. The proposed regulations largely mirror the position that has been in place since 2010 and. Moreover, the community has had a strong expectation that the recommendations of the VBRC will be implemented in practice. This implementation has been met and, indeed, slightly exceeded, insofar as the 37 month inspection regime has been applied generally to electric lines and parts of supply networks in high bushfire risk areas, rather than only to SWER and 22kV lines. In this context, a move to options that would be seen as less rigorous than those currently in place would be likely to prompt a negative community response.

Given the above factors, ESV intends to proceed with the making of the proposed regulations.

9. Implementation, monitoring and enforcement

The *Victorian Guide to Regulation*, a guideline made under the authority of the **Subordinate Legislation Act 1994**, requires that Regulatory Impact Statements (RIS) should include a discussion of the means by which proposed regulations will be implemented, evaluated and reviewed over time.

Specifically the Guide requires that the RIS considers what is required to practically implement the proposed regulations, including discussion of any transitional arrangements that may be necessary to minimise the initial impact of the preferred option or to allow time for supporting business systems (e.g. Information Technology systems needed to support registration and licensing systems) to be developed, tried and tested.

The Guide also requires the RIS to include an explanation of how proposed regulations are to be enforced, including an identification of all the departments and agencies that will have a role in administering and/or enforcing the preferred option.

Implementation

As discussed above, the substance of the proposed regulations, in relation to inspection regimes, has essentially been in effect since 2010. The provisions in relation to the content of the BMP largely mirror those that have been in place for the past decade. Continued implementation of these requirements will occur through the process of annual submission and approval of updated BMP mandated under the Electricity Safety Act 1998. No specific implementation arrangements are therefore required in order to give effect to the regulations.

Monitoring

Data on the incidence of fire ignitions due to electricity assets is routinely collected. Fire starts are reported immediately to ESV if they are significant. Otherwise all minor fire starts are reported within 20 days and included in summary in industry quarterly statistical reports. Information on reporting arrangements is typically found in the BMP prepared by MECs and Specified Operators. For example, Powercor's 2011 Bushfire Mitigation Plan⁴⁴ states:

"Reporting on Ground Fires and Pole Fires is done as they occur and reported to ESV. This is carried out in accordance with:

Work Instruction 05 - W885 - Pole & Ground Fire Reporting

Powercor has an arrangement with the CFA for obtaining monthly attendance figures for all

⁴⁴ Powercor Australia (2011). *Bushfire Mitigation Strategy Plan 2010-2011*. p 57.

fire starts and pole fires. Powercor's ground fire start information is normalised against the CFA fire start statistics. This information is then be reported to Senior Management and supplied to the ESV annually at the end of the fire danger period."

The number of such ignitions is large: for example, the VBRC noted that:

The number of fire starts involving electricity assets remains unacceptably high—at more than 200 starts recorded each year.⁴⁵

That said, there is considerable variation year-on-year due to variations in meteorological factors such as the amount and frequency of rain and variations in temperature.

The combination of the large number of ignitions occurring annually and the inter-locking reporting and monitoring arrangements noted above means that a sound database is available. However, particularly in light of the year to year variation due to meteorological and other factors, it is likely that any trends in bushfire ignitions due to electricity asset failure that emerge due to the changes to the inspection requirements adopted in 2010 will take several years to become apparent.

Asset failure reporting has also been introduced into the new Electrical Safety Management System (ESMS) reports, and reliable trends in this factor are expected to become visible over the medium term - i.e. around 5 – 10 years.

In sum, continued monitoring of trends in ignitions due to electricity assets and asset failures should enable judgements to be made as to the effectiveness of the proposed regulations and, in particular, the increase in stringency of inspection requirements adopted in 2010, over time. That said, the broader policy environment, in which significant actions are being taken to upgrade electricity assets through mechanisms not directly related to enhanced inspection arrangements, means that issues of attribution of any observed reduction in ignitions will necessarily arise.

Compliance and enforcement

ESV carries out annual auditing of those who have BMP obligations under Parts 8 and 10 of the Act. Audits are typically carried in the lead-up to each summer bushfire season.

At present, audits usually comprise a detailed audit of line inspection policies, procedures and in-field practice, together with a general overview of bushfire mitigation activities covered by the regulations and individual bushfire plans and strategies.

In light of the new internal monitoring requirements under the interim and proposed regulations, ESV auditing can also be expected to address how well MECs and specified operators are monitoring the

⁴⁵ VBRC (2010). *Final Report*. Vol 2, p 149.

implementation of their BMP and the effectiveness of their inspections and of processes to rectify any deficiencies that may be identified.

Sanctions

Section 83BB of the Electricity Act provides that specified operators must not operate an at-risk electric line unless a bushfire mitigation plan that applies to the operator's at-risk electric lines has been accepted or provisionally accepted by ESV. Moreover, the specified operator must comply with an accepted bushfire mitigation plan. Penalties for failure to comply with these provisions are established at 300 penalty units for individuals and 1500 penalty units for bodies corporate. Section 98 of the Act makes similar provisions in respect of MECs.

10. Evaluation strategy

An important feature of best practice regulation is that it is reviewed regularly to ensure that it still represents the most appropriate means of meeting the specified objectives. In order to monitor the effectiveness of the preferred regulatory option, an evaluation or review strategy is required. The Victorian Guide to Regulation requires that the RIS includes information on the proposed evaluation or review strategy.

As well as information obtained from annual auditing, ESV receives data from MECs and fire authorities relating to serious electrical incidents, including those involving supply networks. Analysis of this data will help ESV to identify emerging trends in incidents and, over time, may shed light on the effectiveness of the enhanced inspection regime required under the interim and proposed regulations.

In particular, it can be noted that ESV commenced publishing annual reports on MECs' safety performance in 2010. The latest report covers 2011 and was released in August 2012. It is available on ESV's website:

[\[http://www.esv.vic.gov.au/Portals/0/About%20ESV/Files/FINAL%20DRAFT%202011%20Safety%20Performance%20Report%20on%20MECs%20VER13_Release%20date.pdf\]](http://www.esv.vic.gov.au/Portals/0/About%20ESV/Files/FINAL%20DRAFT%202011%20Safety%20Performance%20Report%20on%20MECs%20VER13_Release%20date.pdf)

According to the report (p 27):

"ESV is reporting data that provides good indicators into the safety performance of the industry as a whole and for each MEC, mainly by comparing current data with previous year's data. These indicators measure:

- *the number of fires started by the MEC assets in HBRA's;*
- *the extent to which the MECs managed their powerline maintenance to prevent assets failing that may start fires, particularly in bushfire-prone areas;*
- *the extent to which community safety was impacted by persons infringing the No Go Zone limits or gaining unauthorised access to the MEC assets;*
- *the number and severity of electrical incidents attributable to MEC assets."*

The information contained in the safety performance reports, particularly in relation to number of fires and electrical incidents caused by electrical assets, will enable ESV to evaluate the effectiveness of the regulations over time and, in particular, will assist it in attempting to assess the practical impact of the move to prescribe 37 month minimum inspection frequencies in HBRA, in combination with the adoption of specific qualification requirements for inspectors.

11. Regulatory Change Measurement Assessment

Under the Victorian government's revised Reducing the Regulatory Burden Initiative, announced in 2009⁴⁶, material changes in regulatory costs imposed on business, the not-for-profit sector, the operation of government services and some costs incurred by private individuals by new or amended regulation must be assessed through the preparation of two separate documents: a Business Impact Assessment or Regulatory Impact Statement and a Regulatory Change Measurement. Both documents are required to assess all regulatory costs - i.e. administrative burdens, substantive compliance costs and delay costs. However, while the BIA/RIS requires a benefit/cost analysis to be completed and a range of alternative policy options to be assessed, the RCM simply requires changes in regulatory costs to be measured.

Moreover, a specific methodology is required to be employed in the RCM. This differs from that used in BIA/RIS in some ways. Notably, it provides a greater emphasis on the incidence of the identified costs, highlights the issue of delay costs and, importantly, is based on the measurement of cost changes in *annual* terms, rather than the calculation of costs on a present value basis over the expected life of the regulations.

An RCM report must be employed where there is prima facie evidence that changes in regulatory costs are likely to be material. A regulatory cost change is material if:

- the change in administrative burden experienced by the affected sector is greater than \$250,000 per annum; or
- the change in the sum of compliance costs (including administrative and substantive compliance costs) and costs of delays, experienced by the affected population, is greater than \$500,000 per annum.

Changes in administrative burdens

As discussed, the proposed regulations will be substantively very similar to the current regulations. No additional administrative burdens have been identified as resulting from the minor changes to the current regulations that are proposed. Moreover, should the reduction in the required frequency of resubmission of BMP from annual to five-yearly, discussed in the White Paper released for consultation by ESV, be adopted, the administrative costs associated with the proposed regulations will be reduced significantly from current levels.

⁴⁶ The revised RRBI was announced in the context of the Treasurer's 2008-09 Progress Report on the Reducing the Regulatory Burden (RRB) initiative, available at www.dtf.vic.gov.au/betterregulation. The new requirements are set out in the *Victorian Regulatory Change Measurement Manual*. Department of Treasury and Finance, effective 1 January 2010. See: [http://www.treasury.vic.gov.au/CA25713E0002EF43/WebObj/VictorianRegulatoryChangeMeasurementManual/\\$File/Victorian%20Regulatory%20Change%20Measurement%20Manual.pdf](http://www.treasury.vic.gov.au/CA25713E0002EF43/WebObj/VictorianRegulatoryChangeMeasurementManual/$File/Victorian%20Regulatory%20Change%20Measurement%20Manual.pdf).

In this context, it is clear that this threshold for preparation of an RCM Report has not been met.

Total regulatory costs

As noted above, an RCM is also required if the sum of all changes in regulatory costs exceeds \$500,000 per annum. As indicated above, the proposed regulations are substantively near identical to the current regulations. No significant additional regulatory costs have been identified. Hence, this threshold for preparation of an RCM Report has also not been met.

Conclusion

Given the above, it is not currently proposed to prepare an RCM Report in respect of the proposed regulations.

12. Consultation

As discussed above, the remaking of the current Electricity Safety (Bushfire Mitigation) Regulations 2003 constitutes one element of a program of legislative and regulatory updating and reform currently being undertaken by ESV. Consequently, several stakeholder consultation activities are being undertaken as part of this process. In relation to the proposed regulations, the most relevant consultation initiatives are as follows:

Consultation on the draft regulations

A copy of the first draft of the proposed regulations was sent to all distribution businesses in late September 2012, together with a request for comment. In addition, a meeting was convened at ESV's offices on 8 October 2012, which was attended by all distribution businesses. The majority of distribution businesses also provided written submissions following this meeting.

The submissions and comments received demonstrated few concerns with the provisions of the proposed regulations. In relation to the 37 month inspection cycle in HBRA, assessed above as the primary cost driver for the proposed regulations, no distribution business indicated that it was opposed to the continuation of this requirement, while a number explicitly stated that they did not object to it. That said, some argued that the proposed adoption of a 5 year maximum inspection cycle in relation to overhead electricity assets in LBRA is unnecessary and/or undesirable, with one noting that current practice in its case is to inspect these assets less frequently than five-yearly.

No significant concerns were raised as to other aspects of the specific content required of BMP. In some cases, it was suggested that these inclusions could lead to some duplication, however, it was noted that the BMP should be able to be understood as a stand-alone document, suggesting that these inclusions remained necessary, despite the fact that some matters were also included in ESMS.

A number of suggestions were made in relation to improving the drafting of particular provisions of the proposed regulations, particularly to enhance clarity and certainty and avoid unintended consequences being generated. A large proportion of these suggestions have been adopted.

Questionnaire seeking cost data

As discussed above, a questionnaire was sent in August 2012 to organisations that made submissions in response to the ESV Discussion Paper on potential changes to the legislative and regulatory provisions governing bushfire mitigation. The responses to this questionnaire received from the five distribution businesses formed the basis of the cost analysis set out in this RIS in relation to the preparation of BMP. Given that there was a relatively high level of consistency in the cost estimates generated by the various distribution businesses, these data were employed without any further verification or quality control being undertaken.

Questionnaire seeking cost data - 2011

The cost data used in respect of the prescribed maximum inspection cycle and qualifications requirements for asset inspectors were derived from a questionnaire sent to the affected parties in 2011, as part of the development of the RIS for the amending regulations. As in 2012, usable responses were received from all distribution businesses.

White Paper

A White Paper setting out ESV's preliminary position in relation to proposed amendments to the bushfire mitigation related provisions of the Electricity Safety Act 1998 was published in November 2012. This follows on from the publication of the ESV Discussion Paper earlier in 2012.

One proposal highlighted in the White Paper is to move to a five year cycle for revision and re-submission of BMP, rather than the current annual cycle. This change would, however, be subject to a requirement that any changes in a regulated parties operations that required substantive amendment to the BMP be reflected in a revised BMP that would be submitted to ESV without delay.

Adoption of this change would necessarily reduce the BMP-related costs vis-a-vis those estimated above. The current position of most distribution businesses is in favour of this change. However, Jemena has indicated its belief that the current requirement for a revised BMP to be submitted annually should be retained.

RIS consultation

The final stage in the consultation process in relation to the proposed regulations is the release of this RIS for public comment. The RIS will be published on ESV's website and in the Government Gazette, as well as being advertised in the press. Copies of the RIS will also be sent to the distribution businesses and identified specified operators.

Consultation on the RIS will be undertaken over the 28-day period, as required under the **Subordinate Legislation Act 1994**.

13. Statement of compliance with National Competition Policy

The National Competition Policy Agreements (“NCPA”) set out specific requirements with regard to all new legislation adopted by jurisdictions that are party to the agreements. Clause 5(1) of the Competition Principles Agreement sets out the basic principle that must be applied to both existing legislation, under the legislative review process, and to proposed legislation:

The guiding principle is that legislation (including Acts, enactments, Ordinances or Regulations) should not restrict competition unless it can be demonstrated that:

- (a) The benefits of the restriction to the community as a whole outweigh the costs; and*
- (b) The objectives of the regulation can only be achieved by restricting competition.*

Clause 5(5) provides a specific obligation on parties to the agreement with regard to newly proposed legislation:

Each party will require proposals for new legislation that restricts competition to be accompanied by evidence that the restriction is consistent with the principle set out in sub-clause (1).⁴⁷

Accordingly, every regulatory impact statement must include a section providing evidence that the proposed regulatory instrument is consistent with these NCP obligations. The recently released OECD Competition Assessment Toolkit⁴⁸ provides a checklist for identifying potentially significant negative impact on competition in the RIA context. This is based on the following three questions:

- Does the proposed regulation limit the number or range of suppliers?
- Does the proposed regulation limit the ability of suppliers to compete?
- Does the proposed regulation limit the incentives for suppliers to compete vigorously?

According to the OECD, if all three of these questions can be answered in the negative, it is unlikely that the proposed regulations will have any significant negative impact on competition.

The only aspect of the regulations which could be considered to yield a positive answer to one of these three threshold questions is that of the introduction of a minimum qualification requirement for inspectors. As a general observation, the adoption of mandatory qualifications requirements necessarily implies that some degree of barrier to entry to the occupation is created. This, in turn, may have the effect of limiting the number of range of suppliers of the relevant service. However, a number of factors suggest that the specific provision of the current (and proposed) regulations do not have any material impact in this regard.

⁴⁷ Clause 5, Competition Principles Agreement, 11 April 1995 accessed at www.ncc.gov.au/pdf/PIAg-001.pdf

⁴⁸ See *Integrating Competition Assessment into Regulatory Impact Analysis*. OECD, Paris, 2007. (DAF/COMP(2007)8).

Firstly, the size of the qualification requirement is limited: the qualification accredited for the purposes of the regulations is at Certificate 2 level, which represents one of the lowest qualifications levels in the hierarchy established under Australia's Vocational Education and Training (VET) system. This implies that neither the dollar costs and the time requirement for course completion are likely to be sufficiently large as to deter significant numbers of would-be inspectors. Second, the availability in many cases of government subsidies to meet part of the cost of training will further reduce training costs for the intending inspector, while some employers may also choose to subsidise, or even fully cover, the cost of training.

Third, the VET system includes a formal "Recognition of Prior Learning" (RPL) mechanism. This means that current inspectors who have not completed relevant formal training but who have achieved competence in asset inspection skills through other means (such as informal "on the job" training) are able to be assessed and, subject to competence, awarded the relevant qualification without having to complete the formal training requirement. This further reduces the effective cost of becoming qualified (in terms of both time and money) for many affected individuals.

Finally, the fact that the distribution businesses have not reported any concerns in relation to either the availability or cost of inspectors in the more than two years since the commencement of the interim regulations provides clear evidence that competition issues have not arisen in practice in the industry. Given that the proposed regulations would not change the current qualifications requirements for inspectors, this position is not expected to change.

In sum, it has been concluded that the proposed regulations are fully compliant with the requirements of the National Competition Policy.

Appendix 1: Proposed Electricity Safety (Bushfire Mitigation) Regulations 2013

Electricity Safety (Bushfire Mitigation) Regulations

Exposure Draft

TABLE OF PROPOSALS

<i>Proposal</i>	<i>Page</i>
1 Objective	1
2 Authorising provisions	1
3 Commencement	1
4 Revocation	2
5 Definitions	2
6 Prescribed particulars for bushfire mitigation plans—specified operators	2
7 Prescribed particulars for bushfire mitigation plans—major electricity companies	5
8 Prescribed parts of electric lines excluded	8
9 Prescribed times of inspection	8
10 Prescribed standards of inspection	8
11 Prescribed period in which notice of inspection is to be given	10
12 Prescribed form of notice to be given before inspection	11
13 Exemptions	11
<hr/>	
SCHEDULE—Notice of Inspection	12
<hr/> <hr/>	
ENDNOTES	13



Victoria

Electricity Safety (Bushfire Mitigation) Regulations

Exposure Draft

1 Objective

The objective of these Regulations is to make provision for—

- (a) the preparation of bushfire mitigation plans by specified operators and major electricity companies; and
- (b) the inspection of overhead electric lines and supply networks.

2 Authorising provisions

These Regulations are made under sections 151, 151A and 157 of the **Electricity Safety Act 1998**.

3 Commencement

These Regulations come into operation on 20 June 2013.

4 Revocation

The following Regulations are revoked—

- (a) the Electricity Safety (Bushfire Mitigation) Regulations 2003¹;
- (b) the Electricity Safety (Bushfire Mitigation) Amendment Interim Regulations 2010²;
- (c) the Electricity Safety Amendment (Bushfire Mitigation) Regulations 2011³;
- (d) the Electricity Safety (Bushfire Mitigation) Amendment Regulations 2012⁴.

5 Definitions

In these Regulations—

Australian/New Zealand Wiring Rules means AS/NZS 3000:2007, Australian/New Zealand Standard, 'Electrical installations', as published or amended from time to time;

fire danger period means a period declared under section 4 of the **Country Fire Authority Act 1958** to be a fire danger period;

the Act means the **Electricity Safety Act 1998**;

total fire ban day means a day that has been declared to be a day of total fire ban under section 40(1) of the **Country Fire Authority Act 1958**.

6 Prescribed particulars for bushfire mitigation plans—specified operators

For the purposes of section 83BA(2)(b) of the Act, the following are the prescribed particulars—

- (a) the name, address and telephone number of the specified operator;

- (b) the position, address and telephone number of the person who was responsible for the preparation of the plan;
 - (c) the position, address and telephone number of the persons who are responsible for carrying out the plan;
 - (d) the telephone number of the specified operator's control room so that persons in the room can be contacted in an emergency that requires action by the specified operator to mitigate the danger of bushfire;
 - (e) the bushfire mitigation policy of the specified operator to minimise the risk of fire ignition from its at-risk electric lines;
 - (f) the objectives of the plan to achieve the mitigation of fire danger arising from the specified operator's at-risk electric lines;
 - (g) a description, map or plan of the land to which the bushfire mitigation plan applies, identifying the location of the specified operator's at-risk electric lines;
 - (h) the preventative strategies and programs to be adopted by the specified operator to minimise the risk of the specified operator's at-risk electric lines starting fires;
 - (i) a plan for inspection that ensures that all of the specified operator's at-risk electric lines are inspected at regular intervals of no longer than 37 months;
 - (j) details of the processes and procedures for ensuring that only persons who have satisfactorily completed a training course approved by Energy Safe Victoria are assigned to carry out the inspections referred to in paragraph (i);
-

- (k) details of the processes and procedures for ensuring that persons (other than persons referred to in paragraph (j)) who carry out or will carry out functions under the plan are competent to do so;
- (l) the operation and maintenance plans for the specified operator's at-risk electric lines—
 - (i) in the event of a fire; and
 - (ii) during a total fire ban day; and
 - (iii) during a fire danger period.
- (m) the investigations, analysis and methodology to be adopted by the specified operator for the mitigation of the risk of fire ignition from its at-risk electric lines;
- (n) details of the processes and procedures by which the specified operator will—
 - (i) monitor the implementation of the bushfire mitigation plan; and
 - (ii) audit the implementation of the plan; and
 - (iii) identify any deficiencies in the plan or the plan's implementation; and
 - (iv) change the plan and the plan's implementation to rectify any deficiencies identified under subparagraph (iii); and
 - (v) monitor the effectiveness of inspections carried out under the plan; and
 - (vi) audit the effectiveness of inspections carried out under the plan;

- (o) the policy of the specified operator in relation to the assistance to be provided to fire control authorities in the investigation of fires near the specified operator's at-risk electric lines.

7 Prescribed particulars for bushfire mitigation plans—major electricity companies

- (1) For the purposes of section 113A(2)(b) of the Act, the following are the prescribed particulars—
 - (a) the name, address and telephone number of the major electricity company;
 - (b) the position, address and telephone number of the person who was responsible for the preparation of the plan;
 - (c) the position, address and telephone number of the persons who are responsible for carrying out the plan;
 - (d) the telephone number of the major electricity company's control room so that persons in the room can be contacted in an emergency that requires action by the major electricity company to mitigate the danger of bushfire;
 - (e) the bushfire mitigation policy of the major electricity company to minimise the risk of fire ignition from its supply network;
 - (f) the objectives of the plan to achieve the mitigation of fire danger arising from the major electricity company's supply network;
 - (g) a description, map or plan of the land to which the bushfire mitigation plan applies;
 - (h) the preventative strategies and programs to be adopted by the major electricity company to minimise the risk of the major electricity company's supply networks starting fires;
-

- (i) a plan for inspection that ensures that—
 - (i) the parts of the major electricity company's supply network in hazardous bushfire risk areas are inspected at intervals not exceeding 37 months from the date of the previous inspection; and
 - (ii) the parts of the major electricity company's supply network in other areas are inspected at specified intervals not exceeding 61 months from the date of the previous inspection;
 - (j) details of the processes and procedures for ensuring that only persons who are competent and have satisfactorily completed a training course approved by Energy Safe Victoria are assigned to carry out—
 - (i) inspections referred to in paragraph (i); and
 - (ii) the inspection of private electric lines that are above the ground;
 - (k) details of the processes and procedures for ensuring that persons (other than persons referred to in paragraph (j)) who carry out or will carry out functions under the plan are competent to do so;
 - (l) the operation and maintenance plans for the major electricity company's supply network—
 - (i) in the event of a fire; and
 - (ii) during a total fire ban day; and
 - (iii) during a fire danger period;
-

- (m) the investigations, analysis and methodology to be adopted by the major electricity company for the mitigation of the risk of fire ignition from its supply network;
- (n) details of the processes and procedures by which the major electricity company will—
 - (i) monitor the implementation of the bushfire mitigation plan; and
 - (ii) audit the implementation of the plan; and
 - (iii) identify any deficiencies in the plan or the plan's implementation; and
 - (iv) change the plan and the plan's implementation to rectify any deficiencies identified under subparagraph (iii); and
 - (v) monitor the effectiveness of inspections carried out under the plan; and
 - (vi) audit the effectiveness of inspections carried out under the plan;
- (o) the policy of the major electricity company in relation to the assistance to be provided to fire control authorities in the investigation of fires near the major electricity company's supply network;
- (p) details of processes and procedures for enhancing public awareness of—
 - (i) the responsibilities of owners of private overhead electric lines in relation to maintenance and mitigation of bushfire danger;

- (ii) the obligation of the major electricity company to inspect private overhead electric lines within its distribution area;
 - (q) a description of the measures to be used to assess the performance of the major electricity company under the plan.
- (2) In subregulation (1) *supply network* does not include a terminal station, a zone substation or any part of the major electricity company's supply network that is below the surface of the ground.

8 Prescribed parts of electric lines excluded

For the purposes of section 113F(1) of the Act, the prescribed part of a private electric line is the part of the private electric line above the surface of land that is installed after the point at which the line is connected to a building or other structure (not including a pole) on the land.

9 Prescribed times of inspection

For the purposes of section 113F(1) of the Act, the prescribed times to cause an inspection of private electric lines to be carried out are no later than 37 months after the date of the previous inspection carried out by the major electricity company.

10 Prescribed standards of inspection

- (1) For the purposes of section 113F(1) of the Act, the prescribed standards for the inspection of a private electric line that is above the surface of land are—
- (a) insulators and any stay wires are serviceable and are properly secured to the pole or cross-arm; and
 - (b) cross-arms are serviceable; and

- (c) the conductors and metal ties that secure the conductors to the insulator are serviceable; and
- (d) bare conductors are prevented from clashing; and
- (e) insulation is in serviceable condition; and
- (f) poles must not lean more than 10 degrees from the vertical; and
- (g) in the case of wooden poles other than treated pine poles—
 - (i) the girth of the pole is greater than 550 mm at any point within 200 mm above the ground; and
 - (ii) the pole is free from termites to a depth of 300 mm below the surface of the ground; and
 - (iii) an annulus of at least 50 mm of the wood is free of decay; and
 - (iv) no fruiting fungal bodies are observed; and
- (h) in the case of treated pine poles—
 - (i) the girth of the pole is greater than 450 mm at any point within 200 mm above the ground; and
 - (ii) the pole is free from termites to a depth of 300 mm below the surface of the ground; and
 - (iii) the wood is free from external decay; and

- (i) in the case of tubular and solid steel poles, the thickness of the metal of the pole in any corroded area below the ground is at least 75% of the sound metal above the ground; and
- (j) in the case of concrete poles, the pole—
 - (i) is free of concrete decay; and
 - (ii) does not have exposed metal reinforcement; and
- (k) the line complies with the provisions relating to the clearance space and hazard trees around powerlines in clauses 2(1) and 3 of the Code; and

Note

The Code is prescribed as the Code of Practice for Electric Line Clearance in the Schedule to the Electricity Safety (Electric Line Clearance) Regulations 2010.

- (l) the line complies with the minimum clearance requirements set out in Table 3.8 of the Australian/New Zealand Wiring Rules.
- (2) Subregulations (1)(g)(iii) and (1)(h)(iii) do not apply to wooden poles that are less than 10 years old.

11 Prescribed period in which notice of inspection is to be given

For the purposes of section 113F(2) of the Act, the prescribed period within which notice to the occupier of the land is to be given before inspection of a private electric line is carried out is the period that is not more than 45 days before the inspection and not less than 21 days before the inspection.

12 Prescribed form of notice to be given before inspection

For the purposes of section 113F(2) of the Act, the prescribed form of notice to be given to the occupier of the land before inspection of a private electric line is set out in the Schedule.

13 Exemptions

- (1) Energy Safe Victoria may, in writing, exempt a specified operator or major electricity company from any of the requirements of these Regulations.
 - (2) An exemption under subregulation (1) may specify conditions to which the exemption is subject.
-

SCHEDULE

Regulation 12

NOTICE OF INSPECTION

To the Occupier,

In accordance with section 113F(2) of the **Electricity Safety Act 1998**, please be advised that on or about [*insert date*] our asset inspector will inspect all private electric lines above the surface of land on the property you occupy, except for those parts of the lines that are installed after the point at which they are connected to a building or other structure (not including a pole).

The inspection may reveal that defects exist and maintenance is required on a private electric line on the property that you occupy. If this is the case, we will give the owner written notice of the maintenance work required to be carried out.

Please contact [*insert name of responsible person*] on [*insert telephone number*] if you have any queries.

Signed

[*insert name of major electricity company*]

Electricity Safety (Bushfire Mitigation) Regulations
Exposure Draft

ENDNOTES

¹ Reg. 4(a): S.R. No. 72/2003 as amended by S.R. Nos 111/2010, 110/2011 and 51/2012.

² Reg. 4(b): S.R. No. 111/2010.

³ Reg. 4(c): S.R. No. 110/2011.

⁴ Reg. 4(d): S.R. No. 51/2012.

Table of Applied, Adopted or Incorporated Matter

The following table of applied, adopted or incorporated matter is included in accordance with the requirements of regulation 5 of the Subordinate Legislation Regulations 2004.

Statutory rule provision	Title of applied, adopted or incorporated document	Matter in applied, adopted or incorporated document
Regulation 5 definition of <i>Australian/New Zealand Wiring Rules</i>	Australian/New Zealand Standard, 'Electrical installations', AS/NZS 3000:2007, published 12 November 2007 by Standards Australia.	The whole
Regulation 10(1)(1)	Australian/New Zealand Standard, 'Electrical installations', AS/NZS 3000:2007, published 12 November 2007 by Standards Australia.	Table 3.8