Submission on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016-20

Submission by the Victorian Government

State Government Victoria

The Victorian Government welcomes the opportunity to provide a submission on the preliminary distribution determinations made by the Australian Energy Regulator (AER) for the five Victorian electricity distribution network service providers (DNSPs) for the 2016-20 regulatory control period.

The Victorian Government's primary concern through the revenue determination process is to ensure the regulatory regime builds on the reforms in the Victorian energy market and delivers efficient, well-functioning, productive and competitive markets that continue to serve the long term interests of the Victorian community through efficient access to secure, safe, sustainable and reliable energy.

The Victorian Government generally supports the preliminary distribution determinations that have been made by the AER.

However, there is a significant risk that the expenditure forecasts will significantly increase from the preliminary distribution determination to the final distribution determination with the DNSPs being provided with the opportunity to submit additional information to substantiate specific proposals and to resubmit demand forecasts based on the latest information available. DNSPs are also likely to seek additional expenditure based on proposals accepted by the AER for other DNSPs, for example:

- a step change proposed by Jemena for costs relating to the rule change to transition to cost reflective network pricing
- step changes proposed by CitiPower and Powercor for costs associated with testing Current Transformer (CT) connected meters.

Within this context, this submission provides comments on the following aspects of the DNSPs' preliminary distribution determinations:

- benefits to be realised from the rollout of smart metering
- capital expenditure
- operating expenditure
- the Service Target Performance Incentive Scheme – performance targets
- the allocation of costs between standard control services and metering services

Benefits to be realised from the rollout of smart metering

In an earlier submission on the DNSPs' regulatory proposals and the AER's Issues Paper, the Victorian Government stated that it considered that, with the rollout of smart meters in Victoria substantially complete, the AER should expect the Victorian DNSPs to realise efficiency gains from the rollout. These efficiency gains should be passed through to customers as the benefits are realised, as it is their customers, rather than the DNSPs, that have funded the investment in smart meters through a cost recovery regulatory regime.

In the preliminary distribution determinations, the AER responded that[1]:

> *To the extent that the AMI rollout is mostly complete and the associated benefits have now largely been realised those benefits will be reflected in the service providers' base year expenditure. DEDJTR did not identify or quantify the 'value added benefits' or the further benefits it expects to be realised over the 2016-20 regulatory control period. Without this information we cannot incorporate them into our opex forecast. We note that DEDJTR did not provide us with the independent assessment of the benefit of the AMI program that it referred to.*

The benefits associated with the rollout of smart meters are documented in a public report prepared in 2011 by Deloitte for the Department of Treasury and Finance[2]. Deloitte identified a number of categories of relevant benefits [3]:

[1] For example, *Australian Energy Regulator, Jemena distribution determination 2016 to 2020, Preliminary Decision, Attachment 7 – Operating Expenditure*, October 2015, pages 7-62 – 7-63

[2] Deloitte, *Advanced metering infrastructure cost benefit analysis*, 2 August 2011. Available at http://www.smartmeters.vic.gov.au/about-smart-meters/reports-and-consultations/advanced-metering-infrastructure-cost-benefit-analysis

[3] Ibid, page 58

- avoided costs associated with accumulation meters resulting from the AMI Program
- benefits derived from efficiencies in network operations
- other smaller benefits (incorporating minor efficiencies in network and retail operations).

Each of these benefits is discussed in the following sections.

Avoided costs associated with accumulation meters resulting from the AMI Program

This category comprises two benefits[4]:

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

These benefits have been captured through the preliminary distribution determinations. The DNSPs' revenues for metering services do not include expenditure associated with accumulation meters, time switches or manual meter reading.

Benefits derived from efficiencies in network operations

The AER could take into account the following network operational efficiency benefits identified by Deloitte[5]:

- reduction in unserved energy due to faster detection of outages and restoration times
- avoided cost of proportion of transformer failures on overload and avoided unserved energy

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

Deloitte identified that the faster detection of outages and restoration times would reduce the number of minutes off supply by 3 per cent for CitiPower, 4 per cent for Jemena and United Energy and 5 per cent for AusNet Services and Powercor.[6]

In determining the DNSPs' performance targets for the Service Target Performance Incentive Scheme, the AER has averaged the performance over the last five years. However, the improvements in the System Average Interruption Duration Index (SAIDI) associated with the rollout of smart meters would have been progressively reflected in the historical performance over the last five years; the full benefit would not have been realised in each of the last five years. As a result, the benefit is not fully captured when averaging historical performance over the last five years.

As customers have funded this reliability improvement through their metering charges, the historical performance data should be adjusted to take into account the expected reliability improvement.

The DNSPs would have had the capability to realise this reliability improvement where smart meters have been remotely read. However, the DNSPs may not necessarily have used this capability. Deloitte assumed that the benefits would only start accruing once 80 per cent of smart meters had been installed and were communicating[7].

In the years prior to having 80 per cent of smart meters installed and communicating, the DNSPs' historical performance should be adjusted by the maximum reliability improvement as estimated by Deloitte. In the years after 80 per cent of smart meters were installed and communicating, the DNSPs' historical performance should be adjusted proportionally based on the percentage of smart meters that were not read remotely in that particular year.

[4] Ibid, page 58
[5] Ibid, page 59
[6] Ibid, page 61
[7] Ibid, page 61

Avoided cost of proportion of transformer failures on overload

Deloitte identified that there was a benefit associated with a reduction in the number of transformers failing due to being overloaded. This will result in a lower level of capital expenditure on transformers. The saving was estimated at around $4.8 million per year (in 2015 dollars).

The AER needs to be satisfied that its repex model takes this into consideration when forecasting the replacement capital expenditure required by the DNSPs.

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

The final category of benefits identified by Deloitte was other smaller benefits (incorporating minor efficiencies in network and retail operations). This category, in descending order of the magnitude of the benefits, included (with the Present Value of the benefits for each over the 2008-28 period, at 2008 in 2008 dollars, in brackets)[8]:

— avoided cost of investigation of customer complaints about voltage and quality of supply ($39 million)
— avoided costs of installing import/export metering ($35 million)
— avoided cost of investigation of customer complaints of loss of supply which turn out to be not a loss of supply ($15 million)
— reduction in calls to faults and emergencies lines ($14 million)
— customer benefit of being able to switch retailer more quickly and more certainly ($8 million)
— reduced cost of network loading studies for network planning ($5 million)
— avoided cost of replacing service fuses that fail from overload ($5 million)
— avoided cost of proportion of HV/LV transformer fuse operations on overload ($5 million)
— reduction in calls related to estimated bills and high bill enquiries ($5 million)
— avoided cost of supply capacity circuit breaker ($4 million)
— avoided cost of end of line monitoring ($4 million)
— avoided cost of communications to feeder automation equipment ($3 million)

Some of these benefits are realised directly by customers (avoided costs of installing import/export metering and ability to switch retailer more quickly and more certainly). Other benefits are realised by retailers, and would be passed through to customers in a competitive market (reduction in calls related to estimated bills and high bill enquiries). The remaining benefits are realised by the DNSPs and need to be considered by the AER as part of the distribution determination, if they are to be passed through to consumers.

Smaller benefits that are realised by DNSPs

Of the smaller benefits that are realised by DNSPs, the most material reductions in operating expenditure are from the avoided cost of investigation of customer complaints about voltage and quality of supply and about loss of supply which turn out to be not a loss of supply, reduction in calls to faults and emergencies lines, and reduced cost of network loading studies for network planning. A recent review undertaken by the Department indicates that the DNSPs are in the early stages of realising these benefits and therefore they would not be reflected in their revealed 2014 operating expenditure. The estimated annual savings are $12.4 million (in 2015 dollars).[9] The AER would need to determine how the savings are allocated across the DNSPs and the extent to which these savings are reflected in the base operating expenditure.

[8] Ibid, pages 78-80
[9] The Deloitte report publishes the net present value pf the benefits over the 2008-28 period in 2008 dollars. The annual benefit is calculated based on a discount rate of 8 per cent, and the required timeframe for the rollout of smart meters (as gazetted at that time).

The remaining benefits are capex-related with annual savings around $8 million in aggregate. As the distributors only recover the return on and return of any capital expenditure within the regulatory control period, the impact of these savings are immaterial relative to the other benefits considered.

Capital expenditure

Customer contributions for new connections

The customer contributions for new connections that have been accepted by the AER are based on the Essential Service Commission's *Electricity Guideline No. 14: Provision of Services by Electricity Distributors* (Guideline 14). Guideline 14 states that the incremental revenue for a new connection is calculated assuming that the X-factor in the final year of the current regulatory control period applies in subsequent years.[10]

The Victorian Government has decided that Chapter 5A of the National Electricity Rules will apply from 2016 or 2017, to align Victoria with the national framework. The incremental revenue will be calculated in accordance with the AER's *Connection charge guidelines for electricity retail customers*. Under these guidelines, the incremental revenue for a new connection is calculated assuming that the real distribution charges in the final year of the current regulatory control period apply in subsequent years.[11]

The effect of this difference on the customer contributions will vary from DNSP to DNSP depending on the X factor for 2020.

The X-factor for AusNet Services and United Energy is 0.00 per cent for 2020. The change in the regulatory framework for new connections will have no effect on the forecast customer contributions for these DNSPs.

The X-factor for CitiPower, Jemena and Powercor is negative, indicating a real increase in revenue in 2020. The incremental revenue that will be assumed to be earned by these DNSPs' new connections will be higher under the national regime than the state-based regime, resulting in lower customer contributions. The proportion of the cost of connection paid for by the connecting customer will decrease and the proportion of the cost paid for by other customers will increase. As the X-factors are less than 1 per cent, the difference is not expected to be material.

The Government will inform the AER when the Chapter 5A arrangements will commence.

Customer contributions for the Powerline Replacement Fund

The AER has accepted $60 million forecast by Powercor for customer contributions for the Victorian Government's Powerline Replacement Fund for the replacement of assets in high bushfire risk areas. The AER[12]:

> *… is satisfied that the Victorian Government has provided sufficient surety of the continuation of this program into the forecast period.*

The AER has not made a similar decision with respect to AusNet Services, which is also a recipient of grant funding under the Powerline Replacement Fund.

In September 2014, the AER determined a positive cost pass through amount for AusNet Services based on the tax that was payable on grant funding provided by the Victorian Government through the Powerline Replacement Fund. On 15 October 2015, the AER determined an equivalent but negative pass through amount as AusNet Services had received a private ruling from the Australian Tax Office that tax is not payable on the grant funding.

[10] Clause 3.3.3(a)(2)(B)

[11] Clause 5.3.5(b)

[12] Australian Energy Regulator, *Powercor distribution determination 2016 to 2020, Preliminary Decision, Attachment 6 – Capital expenditure*, October 2015, page 6-85

In September 2014, the AER similarly determined a positive cost pass through amount for Powercor but has not received an application from Powercor for an offsetting negative cost pass through amount.

The Victorian Government strongly supports the approach taken by the AER in its treatment of Ausnet Services third party capital contribution tax relief. It remains unclear why the decision applied to Ausnet Services has not been applied to Powercor. If it relates to the private ruling that has been made by the Australian Tax Office, it is unclear why the AER has not applied the efficient and prudent benchmarking operator approach in relation to tax as it does in determining other capital expenditure allowances.

The AER needs to consider the incentives created by including $60 million in Powercor's forecast expenditure. If the expenditure relates to tax payable on grant funding, it weakens the incentive for Powercor to obtain a positive ruling from the Australian Tax Office, and if they do receive a positive ruling, provides a windfall gain for Powercor on grant funding provided by Victorian taxpayers.

Future regulatory obligations

In its preliminary distribution determination, the AER noted the work "being undertaken by the Victorian Government to develop suitable regulatory standards for the use of new technologies such as Rapid Earth Fault Current Limiting (REFCL) devices and a new type of insulated line as major tools to reduce the risk of powerline faults igniting bushfires"[13].

At the time that the preliminary distribution determination was made, the Victorian Government had not published the proposed regulations. The proposed regulations and Regulatory Impact Statement have subsequently been published and are available at http://www.energyandresources.vic.gov.au/energy/safety-and-emergencies/powerline-bushfire-safety-program/proposed-electricity-safety-bushfire-mitigation-further-amendment-regulations.

In the absence of the proposed regulations, the AER proposed that the future regulatory obligations be treated as two contingent projects – one for REFCLs and one for powerline replacement – with each contingent project containing one or more tranches, subject to a three part trigger. The three triggers are[14]:

1. Passage by the State of Victoria of a law or regulations or other regulatory instrument that gives effect to recommendation 27 of the Victorian Bushfires Royal Commission, whether in part or in full.
2. The formation of capital projects into tranches. All the projects which constitute a tranche must be listed in a regulatory instrument or a bushfire mitigation plan approved by Energy Safe Victoria for completion in the 2016-20 regulatory control period.
3. Every project incorporated in a tranche must be the subject of a detailed design investigation which accurately identifies the scope of works and proposed costings.

The Victorian Government has a number of concerns with this approach:

- The proposed capital expenditure for a contingent project must exceed $30 million or 5 per cent of the value of the annual revenue requirement for 2016, whichever is the larger.
  - AusNet Services and Powercor are likely to each have two tranches of expenditure for REFCLs during the 2016-20 regulatory control period. The first tranche will required to be completed by 2018 and the subsequent tranche by 2020.
  - AusNet Services and Powercor are highly unlikely to have sufficient incremental expenditure on powerline replacement to meet the contingent project expenditure threshold. On the basis that powerlines are progressively replaced with new insulated conductor technology over a 50 year timeframe, the total expenditure on powerline replacement over a 50 year period is around $408 million; $42 million more than replacing the powerlines with bare wire conductor. The expected incremental cost over a five year regulatory control period per DNSP is around $2.1 million. On an

[13] For example, Australian Energy Regulator, *AusNet Services distribution determination 2016 to 2020, Preliminary Decision, Attachment 6 – Capital expenditure*, October 2015, page 6-84
[14] Ibid, page 6-86

annual basis (approximately $0.4 million), this is immaterial relative to the total forecast capital expenditure.
– Furthermore, it is expected that there will be few new powerlines that will need to be insulated in the "codified areas" as these are not in high growth areas.

The Victorian Government does not support forecasting the expenditure required to meet these future regulatory obligations as part of the final distribution determination.

As indicated above, the Victorian Government considers that the incremental cost of replacing powerlines with insulated conductor rather than bare wire conductor is likely to be immaterial relative to the total forecast capital expenditure and the level of accuracy associated with that forecast. Given the low incremental expenditure for powerline replacement activities, the Victorian Government considers both REFCLs and powerline replacement could be considered as a single contingent project within each of the two tranches. Adopting this approach has two advantages:

- The REFCL targets required within the legislation should satisfy the contingent project threshold triggers.
- All parties will be able to track the replacement of bare wire powerlines within the 33 declared areas.

Additionally, greater clarity needs to be provided as to how applications for contingent REFCLs projects will be approved to ensure that the DNSPs are able to meet the regulatory obligation.

Expenditure on SCADA and IT

The AER has recognised that the expenditure on SCADA systems and IT is lumpy in nature. For example, the AER states that[15]:

We recognise there will be period-on-period changes to repex requirements that reflect the lumpiness of the installation of assets in the past.

That said, the AER considers that[16]:

… if the forecast expenditure for the next period is similar or lower than the expenditure in the last period, the distributor's forecast is likely to satisfy the capex criteria.

As a result, in many cases, there has been little assessment of the DNSPs' proposed expenditure on SCADA systems and IT expenditure. As an example, AusNet Services' expenditure on non-network capex, which includes IT, was high in 2011-15 compared to 2001-10. However, as the forecast expenditure for 2016-20 is less than in 2011-15, but still significantly higher than in 2001-10, the AER appears to have undertaken a fairly cursory assessment of the expenditure before concluding that it reflects efficient costs.

This approach provides a perverse incentive to maintain a more consistent level of spending, rather than incur lumpy expenditure that would be expected for these expenditure categories.

Operating expenditure

Vegetation management

The AER did not accept a step change in operating expenditure sought by Jemena and United Energy for the additional costs to comply with the Electrical Safety (Electric Line Clearance) Regulations 2015 (ELC 2015) compared to the costs to comply with the Electrical Safety (Electric Line Clearance) Regulations 2010 (ELC 2010).

[15] For example, Australian Energy Regulator, *AusNet Services distribution determination 2016 to 2020, Preliminary Decision, Attachment 6 – Capital expenditure*, October 2015, page 6-68
[16] Ibid, page 6-69

The AER has identified that there are cost increases associated with compliance with AS4373 "Pruning of amenity trees" and notification and consultation requirements, and cost decreases associated with the reintroduction of exceptions for structural tree branches in relation to both insulated and uninsulated electric lines. The AER states that[17]:

The ESV considered that the removal of these exceptions in ELC 2010 increased costs over time and expects that the reintroduction of these exceptions in ELC 2015 should decrease pruning costs over time.

During the development of the Regulatory Impact Statement for ELC 2015, the DNSPs advised that the indicative estimate for complying with AS4373 was $4.2 – 8.4 million[18].

In its preliminary distribution determinations, the AER provided the vegetation management costs for 2009-13 for AusNet Services, Powercor and United Energy. The vegetation management costs incurred in 2009, with vegetation management in accordance with Electrical Safety (Electric Line Clearance) Regulations 2005 (ELC 2005) (which included exceptions for structural tree branches), are compared with the vegetation management costs incurred in 2013, with vegetation management in accordance with ELC 2010 (with no exceptions), in **Table 1**.

TABLE 1 VEGETATION MANAGEMENT EXPENDITURE

DNSP	2009 (ELC2005)		2013 (ELC2010)	
	Vegetation management expenditure	% of opex	Vegetation management expenditure	% of opex
	$ million, $2015		$ million, $2015	
AusNet Services	16.5	10	48.0	24
Powercor	16.5	11	47.9	24
United Energy	4.8	5	14.9	12
Total	**37.8**		**110.8**	

SOURCE: AUSTRALIAN ENERGY REGULATOR, AUSNET SERVICES DISTRIBUTION DETERMINATION 2016 TO 2020, PRELIMINARY DECISION, ATTACHMENT 7 –OPERATING EXPENDITURE, *OCTOBER 2015, PAGE 7-37, AUSTRALIAN ENERGY REGULATOR,* POWERCOR DISTRIBUTION DETERMINATION 2016 TO 2020, PRELIMINARY DECISION, ATTACHMENT 7 –OPERATING EXPENDITURE, *OCTOBER 2015, PAGE 7-42, AUSTRALIAN ENERGY REGULATOR,* UNITED ENERGY DISTRIBUTION DETERMINATION 2016 TO 2020, PRELIMINARY DECISION, ATTACHMENT 7 –OPERATING EXPENDITURE, *OCTOBER 2015, PAGE 7-38*

Table 1 indicates that the additional costs incurred under ELC 2010 relative to under ELC 2005, with the removal of the exceptions, was $73 million for these three DNSPs alone. If the costs associated with vegetation management decrease to the same extent with the introduction of ELC 2015, then the expected cost decreases are well in excess of the expected cost increases.

When the ESV has issued guidance notes on how it will administer ELC 2015, the AER should be assessing a negative step change in operating expenditure for each of the DNSPs, not just those that proposed a positive step change.

Change in capitalisation policy – corporate overheads

The AER has accepted a change in capitalisation policy proposed by CitiPower and Powercor. The AER has agreed to an adjustment to the base operating expenditure for CitiPower of $17.7 million and for Powercor of $32.0 million on the basis of the average capitalised overheads over the 2012-14 period.

It is unclear why the AER has chosen to average the capitalised overheads over the 2012-14 period. Given that no efficiency sharing scheme applies to capital expenditure during this period, and the AER considers that the incentives for efficiency gains are greater at the beginning of the regulatory control

[17] Australian Energy Regulator, *United Energy distribution determination 2016 to 2020, Preliminary Decision, Attachment 7 – Operating expenditure*, October 2015, page 7-67
[18] Jaguar Consulting, *Regulatory Impact Statement, Electricity Safety (Electric Line Clearance) Regulations 2015*, September 2014, page 6

period in the absence of an efficiency sharing scheme, then the capitalised overheads should be averaged over a five year period, that is, over the 2010-14 period.

Such an approach is consistent with averaging performance over the 2010-14 period when rolling forward the performance targets for the Service Target Performance Incentive Scheme.

Guaranteed Service Level (GSL) payments scheme

The Essential Services Commission (ESC) has reviewed the Victorian GSL payments scheme that will apply from 1 January 2016. In its Final Decision, the ESC proposed a number of changes to the Victorian GSL payments scheme, including lower thresholds for making GSL payments to customers experiencing a high number of sustained interruptions in a year, increased payment levels for all GSL payment measures, and a new GSL payment for each long duration interruption.

In its final distribution determination, the AER will need to take into consideration the outcomes of this review in the forecast operating expenditure for the DNSPs.

Service Target Performance Incentive Scheme – performance targets

The AER's Service Target Performance Incentive Scheme (STPIS) states that the performance targets must be based on average performance over the last five regulatory years, modified by the following[19]:

(1A) any reliability improvements completed or planned where the planned reliability improvements are:

- *(i) included in the expenditure program proposed by the DNSP in its regulatory proposal, or*
- *(ii) proposed by the DNSP, and the costs of the improvements is allowed by the relevant regulator, in the DNSP's previous regulatory proposal or regulatory submission, and*
- *(iii) expected to result in a material improvement in supply reliability.*

The AER has accepted a couple of expenditure proposals that would be expected to result in a material improvement in supply reliability, but has not made any modifications to the DNSP's performance targets for the 2016-20 regulatory control period.

Jemena – installation of Rapid Earth Fault Current Limiters

The AER has accepted Jemena's proposal to install Rapid Earth Fault Current Limiters (REFCLs) at four zone substations – Sydenham, Sunbury, Coolaroo and Craigieburn.

There are significant fire safety and reliability benefits associated with the installation of REFCLs. A study by Northpower in New Zealand found that with their REFCL installation[20]:

91% of all earth-faults were compensated successfully .. and they saw a 61% improvement in SAIDI.

The AER's preliminary distribution determination for Jemena indicates that the REFCLs have been justified on the basis of fire safety and reliability benefits[21]. To ensure that customers are not paying for the REFCLs twice – through the forecast capital expenditure and through the STPIS, the AER should take these reliability benefits into consideration in determining the performance targets for Jemena for the 2016-20 regulatory control period.

AusNet Services – installation of automatic circuit reclosers, and animal and bird proofing

In its preliminary distribution determination for AusNet Services, the AER has identified that:

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[19] Australian Energy Regulator, *Electricity distribution network service providers, Service target performance incentive scheme,* November 2009, clause 3.2.1(a)(1A)

[20] Rao, Mengyun, *Assessing Ground Fault Neutraliser (GFN) deployment and benefits in 11kV Electricity Network* – Power Systems Group, University in Auckland quoted in Keen, Dennis and Macdonald, Steve, *Darsfield to Dunsandel and Beyond – The Development of the Ground Fault Neutralizer in New Zealand and Lessons Learne*d, EEA Conference & Exhibition 2013, 19-21 June, Auckland

[21] Australian Energy Regulator, *Jemena distribution determination 2016 to 2020, Preliminary Decision, Attachment 6 – Capital expenditure*, October 2015, pages 6-90 – 6-91

… in its published planning report and regulatory proposal capex overview, AusNet Services attributed the reliability improvement of its SAIDI measures to smart asset management and investment in feeder automation, installation of automatic circuit recloser and animal proofing measures.

As customers have funded the installation of automatic circuit reclosers (ACRs) through a positive cost pass through determination[22], and as the reliability benefits are material enough for AusNet Services to specifically identify them in its published planning report and regulatory proposal capex overview, the AER should take the reliability benefits associated with the ACRs into consideration in determining the performance targets for AusNet Services for the 2016-20 regulatory control period.

AusNet Services' forecast capital expenditure for the 2011-15 regulatory control period included the expenditure for animal proofing measures[23]. As customers have funded the investment in this measure to improve reliability, and as the reliability benefits are material enough for AusNet Services to specifically identify them in its published planning report and regulatory proposal capex overview, the AER should take the reliability benefits associated with the animal proofing measures into consideration in determining the performance targets for AusNet Services for the 2016-20 regulatory control period.

The AER has accepted capital expenditure of $57.1 million over the 2016-20 regulatory control period for more animal and bird proofing.[24] The reliability benefits associated with this additional bird and animal proofing should also be taken into consideration in determining AusNet Services' performance targets for the 2016-20 regulatory control period.

Contingent projects - REFCLs

As advised in a submission on the DNSPs' regulatory proposals, the Victorian Government is funding powerline replacement[25] in the most dangerous areas of the state and is currently considering regulating the installation of REFCLs in the highest consequence bushfire risk areas. Both the powerline replacement and REFCLs are expected to improve the supply reliability in the areas targeted.

The AER has determined that the DNSPs will be able to recover the expenditure associated with the future regulatory obligations as contingent projects.[26] The AER has developed a three part trigger for these contingent projects.

In making a determination on a contingent project, the National Electricity Rules state that the AER must have regard to[27]:

… whether the capital and operating expenditure forecasts for the contingent project are consistent with any incentive scheme or schemes that apply to the Distribution Network Provider …

As discussed above, there are reliability benefits associated with the installation of REFCLs. In making its determination on the contingent projects, the AER must take into consideration any potential revenue increments that the DNSP will receive under the STPIS.

Allocation of costs between standard control services and metering services

In its preliminary distribution determinations, the AER identified that each of the DNSPs had taken a different approach to allocating costs between standard control services and metering services.[28] It recognised that the cost allocation approaches by incumbent metering providers have the potential to

[22] Australian Energy Regulator, *SP AusNet cost pass through application of 31 July 2012 for Costs arising from the Victorian Bushfire Royal Commission PUBLIC*, 19 October 2012, page 41

[23] Australian Energy Regulator, *Victorian electricity distribution network service providers, Distribution determination 2011-2015, Final decision - appendices*, October 2010, pages 633, 637, 661 and 675

[24] Australian Energy Regulator, *AusNet Services distribution determination 2016 to 2020, Preliminary Decision, Attachment 6 – Capital expenditure*, October 2015, page 6-44

[25] Putting powerlines underground or replacing bare overhead wires with insulated conductor.

[26] For example, Australian Energy Regulator, *Powercor distribution determination 2016 to 2020, Preliminary Decision, Attachment 6 – Capital expenditure*, October 2015, pages 6-123 – 6-126

[27] National Electricity Rules, clause 6.6A.2(g)(9)

[28] For example, Australian Energy Regulator, *AusNet Services distribution determination 2016 to 2020, Preliminary Decision, Attachment 7 – Operating Capital expenditure*, October 2015, page 7-39

affect competition from new entrants and competition between existing DNSPs.[29] However, it considered that any cost allocation issues relating to metering costs would be best dealt with in the development of a Distribution Ring Fencing Guideline that it is required to develop and publish by 1 December 2016.

The Victorian Government has a number of concerns with this approach:

— to the extent that costs recovered through the metering charges for small customers are for services required by all the DNSPs' customers, not just small customers, small customers are subsidising other (larger) customers
— the metering charges for small customers will therefore be higher than they would otherwise
— by setting metering charges that are higher than they should, new entrants may choose to enter the competitive metering market but any investment by them may be inefficient if they are unable to compete when the metering charges are reduced by removing the cross subsidies.

As the AER has recognised that there is an issue with the allocation of costs between standard control services and metering services, it is incumbent upon it to resolve the issue to the best of its ability now. However, it is recognised that the AER may not be able to completely resolve all the issues now.

It is expected that the DNSPs will submit an application for a cost pass through event when metering competition commences. If the AER is not able to completely resolve the cost allocation issue now, it will have the opportunity to resolve any residual issues as part of the cost pass through application.

The Victorian Government has previously raised it concerns on this issue. The AER's preliminary distribution determination indicates that it has misunderstood the concerns raised. The preliminary distribution determination stated that the Victorian Government's previous submission[30]:

… agreed that some of these costs may be standard control services but considered there was a risk that consumers would be paying for these costs twice. As we have not allocated any AMI costs to standard control services opex, there is no risk of consumers paying for these costs twice.

The previous submission was referring to the risk of consumers having paid twice for costs during the 2011-15 regulatory control period. It was not referring to 2016-20 regulatory control period, as inferred by the AER's preliminary distribution determination.

During the 2011-15 regulatory control period, standard control services were regulated under an incentive-based regime and the metering services were regulated under a cost recovery regime. As a result, the DNSPs could have forecast, and the AER accepted, expenditure for standard control services in the distribution determination for the 2011-15 regulatory control period. The DNSPs could then have allocated that expenditure to metering services and recovered the actual expenditure through metering service charges, while at the same time recovering the forecast expenditure through network charges.

That said, if the allocation of costs between standard control services and metering services is not resolved as part of this distribution determination, the risk of consumers paying twice will increase.

[29] Ibid, page 7-40
[30] Ibid

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