



Preliminary framework and approach

**AusNet Services, CitiPower,
Jemena, Powercor and United
Energy**

**Regulatory control period
commencing 1 January 2021**

September 2018

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2021–25 89**

Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Allowance Mechanism, DMIAM	demand management innovation allowance mechanism
capex	capital expenditure
CESS	capital expenditure sharing scheme
COAG	Council of Australian Governments
CPI	consumer price index
DMIS	demand management incentive scheme
distributor, DNSP	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ESCV	Essential Services Commission of Victoria
expenditure assessment guideline	expenditure forecast assessment guideline for electricity distribution
GSL	guaranteed service level
F&A	Framework and approach
kWh	kilowatt hours
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the rules	National Electricity Rules
next regulatory control period	1 January 2021 to 31 December 2025
Opex	operating expenditure
RAB	regulatory asset base

Shortened Form**Extended Form**

STPIS

service target performance incentive scheme

Overview

The Framework and Approach (F&A) is the first step in a two year process to determine efficient prices for electricity distribution services in Victoria for the 2021 to 2025 regulatory control period. The F&A determines, amongst other things, which services we will regulate and the broad nature of the regulatory arrangements. This includes an assessment of services (service classification) and whether we need to directly control the prices and/or revenues set for those services. The F&A also facilitates early consultation with consumers and other stakeholders and assists electricity distribution businesses prepare regulatory proposals.

This preliminary F&A outlines changes we are proposing that will affect the regulated services offered by the Victorian distributors in the future.

Our preliminary view is that the F&A should be revised to reflect rule changes and the development of new incentive schemes and regulatory guidelines that will apply to the Victorian distributors.

In particular, late last year, the Australian Energy Market Commission (AEMC) changed the National Electricity Rules (NER) to amend the framework we use to classify the distributors' electricity distribution services.¹ As a result of this rule change, the Australian Energy Regulator (AER) is developing a Distribution Service Classification Guideline and Exempt Assets Guideline, and will release final Guidelines by 30 September 2018. We intend to apply these Guidelines in making the final F&A for Victorian distributors, to be released in January 2019. Recent amendments to the *National Electricity (Victoria) Act 2005* provide for the application of Chapter 5A of the NER and the AER's connection charge guideline to Victorian distributors.

Further, we developed a new demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIAM or Allowance Mechanism)² and have implemented a NEM-wide Ring-fencing Guideline.³ These changes to the regulatory environment that the Victorian distributors operate in have been reflected in this preliminary F&A. On the other hand, Power of Choice reforms that introduced metering contestability to residential electricity consumers in other jurisdictions have not yet been applied in Victoria.⁴ In 2017 the Victorian Government deferred metering competition in Victoria through an Order-In-Council.⁵ This means the approach to the classification of metering services remains unchanged from that of the existing determination.

¹ AEMC, final rule determination - National Electricity Amendment (Contestability of Energy Services) 2017.

² See: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism>.

³ AER, *Ring-fencing guideline electricity distribution*, Version 2. October 2017. See: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-october-2017>.

⁴ See: <http://www.aemc.gov.au/Major-Pages/Power-of-choice>.

⁵ Victorian Government Order-In-Council, No. S 346, 12 October 2017.

Following release of this Preliminary F&A, we will consult with interested parties before issuing our final F&A by 31 January 2019. Table 1 summarises our Victorian distribution determination process.

Table 1 Victorian distribution determination process

Step	Date
AER publishes preliminary F&A for Vic distributors	14 September 2018
Stakeholder forum	25 October 2018
Submissions on preliminary F&A for Vic distributors close	9 November 2018
AER to publish final F&A for Vic distributors	31 January 2019
Vic distributors submit regulatory proposals to AER	31 July 2019
AER publishes issues paper and holds public forum	October 2019*
Submissions on regulatory proposal close	November 2019
AER to publish draft decisions	March 2020
AER to hold a predetermination conference	April 2020
Vic distributors to submit revised regulatory proposals to AER	June 2020
Submissions on revised regulatory proposals and draft decisions close	July 2020*
AER to publish distribution determinations for regulatory control period	31 October 2020

* The date provided is based on the AER receiving compliant proposals. The date may be altered if we receive non-compliant proposals.

Source: NER, chapter 6.

Background

The AER is the economic regulator for transmission and distribution electricity and gas network businesses across Australia (excluding Western Australia). Our powers and functions for the electricity sector are set out in the National Electricity Law (NEL) and NER.

AusNet Services, CitiPower, Jemena, Powercor and United Energy are the licensed, regulated operators of Victoria's monopoly electricity distribution networks connected to the National Electricity Market (NEM). The distribution network comprises the poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and businesses. The Victorian distributors design, construct, operate, and maintain their distribution network for Victorian electricity consumers.

We make regulatory decisions on the revenues the Victorian distributors can recover from their customers. We determine Victorian distributors' revenue by an assessment of their efficient costs and forecasts. Our assessment is based on a regulatory proposal submitted by the Victorian distributors in advance of a regulatory control period, in this case beginning 1 January 2021. Regulatory proposals set out the network businesses' views on their expected costs, services, incentive schemes and required revenues. Our regulatory determinations set out our decisions on these issues.

The regulatory framework we administer is based on an incentive regime. We set a network business' allowed revenue for a period (typically five years) based on the best available information, rigorous assessment and consideration of consumers' views. Network businesses are then provided with incentives to outperform the revenue we determine. A network business retains any savings for a period of time before those savings are passed to customers through lower network bills.

This chapter provides an overview of our preliminary positions on:

- classification of distribution services (which services we will regulate)
- incentives schemes for service quality, capital expenditure and operating expenditure and demand management
- expenditure forecasting tools to test the network businesses' regulatory proposals
- how we will calculate depreciation of the network businesses' regulatory asset bases

It also sets out our preliminary positions on:

- control mechanisms (how we will determine prices for regulated services)
- how we will price transmission assets (dual function assets).

We summarise below our preliminary approach to each of the above matters. More detailed discussion of each matter is set out in the following chapters.

Classification of distribution services

We regulate distribution services provided by the Victorian distributors. Service classification determines which services will be regulated and how. We will regulate services that are provided on a monopoly basis under a price or revenue cap or other mechanism to control the charges that a distributor can levy customers. Less prescriptive regulation is required where the prospect of competition exists. In some situations we may remove regulation altogether.

Unregulated distribution services must be provided through either a separate affiliate to the distributor or the distributor must demonstrate functional separation from the distributor's direct control services,⁶ in accordance with our Ring-fencing Guideline.⁷ In broad terms, this

⁶ Functional separation may include physical separation of offices, staff separation, accounting separation and separate branding/avoiding cross-promotion. See AER, *Ring-fencing guideline electricity distribution*, October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, available at <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-october-2017> and

means that while existing regulated distribution services will continue to be provided by the distributor, all unregulated distribution services or new services that come into existence within a regulatory control period must be provided separately to the regulated network business. That is, unless we approve a waiver as permitted under the Ring-fencing Guideline.

The AEMC made a rule change to the NER in December 2017, which applies to the Victorian electricity distributors for the 2021–25 regulatory control period.⁸ As part of the AEMC's determination, we are required to develop and publish a service classification guideline by 30 September 2018, which will provide further clarity and transparency around how we classify services.⁹

The rule change made it easier for us to change the classification of services regardless of how services have been historically classified. More specifically, the rule change removed the requirement for us to not alter service classification unless another classification is clearly more appropriate.¹⁰ This mandatory requirement had previously constrained our ability to move away from the status quo when considering service classification.¹¹

Table 2 provides an overview of the service classifications available to us for the purposes of economic regulation under the NER.

Table 2 Classifications of distribution services

Classification		Description	Regulatory treatment
Direct control service	Standard control service	Services that are central to electricity supply and therefore relied on by most (if not all) customers such as building and maintaining the shared distribution network. Most distribution services are classified as standard control.	We regulate these services by determining prices or an overall cap on the amount of revenue that a distributor may earn for all standard control services. The costs associated with these services are shared by all customers via their regular electricity bill.
	Alternative control service	Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than only by the local distributor.	We set service specific prices to provide a reasonable opportunity to enable the distributor to recover the efficient cost of each service from customers using that

⁷ <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-2016>.

⁸ AER, *Ring-fencing guideline electricity distribution*, October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

⁹ See <http://www.aemc.gov.au/Rule-Changes/Contestability-of-energy-services>.

¹⁰ See: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/distribution-service-classification-guidelines-and-asset-exemption-guidelines>.

¹¹ Formerly clause 6.2.1(d), now deleted.

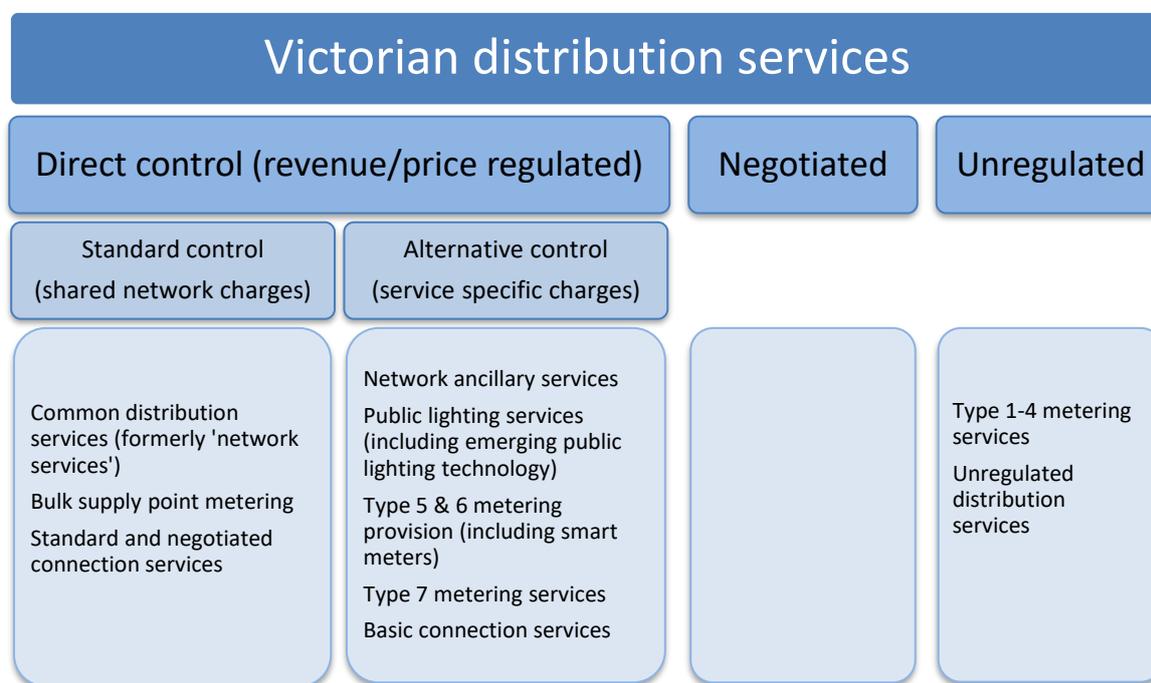
¹¹ The rule change also requires us to develop and publish service classification guidelines by September 2018, which will provide further clarity and transparency around how we classify services. See clause 6.2.3A.

Negotiated service	Services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient countervailing power to negotiate the provision of those services.	service. Distributors and customers are able to negotiate service and price according to a framework established by the NER. We are available to arbitrate if necessary.
Unregulated distribution services	Distribution services that are contestable will not be classified.	We have no role in regulating these services.
Non-distribution services	Services that are not distribution services. ¹²	We have no role in regulating these services.

Source: AER

Our preliminary position is to change the classification of some of the Victorian distribution services for the 2021–25 regulatory control period. While we propose to retain the existing service classifications for most services, we intend to clarify service descriptions to better align with the services being provided, and create consistency and predictability across jurisdictions as far as practicable in how distribution services might be classified. An overview of our proposed service classifications for the Victorian network businesses is set out in figure 1 below.

Figure 1 AER proposed classification of Victorian distribution services



Source: AER

¹² The NER defines a distribution service as a service provided by means of, or in connection with, a distribution system. NER, Chapter 10, glossary.

Our final F&A decision on service classification is not binding for our determination on the Victorian network businesses' regulatory proposals. However, under the NER we may only change our classification approach in making the determination if a material change in circumstances justifies a departure from our final F&A position.¹³ Our Service Classification Guideline, which is due to be finalised by 30 September 2018, could trigger some refinements to the service classifications set out in this F&A paper. We expect that these changes will be incorporated in the Victorian distribution services list in the final F&A, to be released in January 2019.

Form of control

Following on from service classifications, our determinations impose controls on direct control service prices and/or their revenues.¹⁴ We may only accept or approve control mechanisms in a distributor's regulatory proposal if they are consistent with our final F&A, unless we consider there has been a material change in circumstances and we consider no form of control mechanism set out in the final F&A should apply to that distribution service.¹⁵ In deciding control mechanism forms, we must select one or more from those listed in the NER.¹⁶ These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.

Our preliminary position on the form of control mechanisms for the Victorian network businesses is to retain the long standing approaches of:

- Revenue cap — for services we classify as standard control services.
- Revenue cap — for types 5 and 6 (including smart meters) metering services we classify as alternative control services.
- Caps on the prices of individual services — for other services we classify as alternative control services.

For standard control services, the NER mandates that the basis of the control mechanism must be the prospective CPI-X form or some incentive-based variant.¹⁷

Our final F&A decision on the form of control is binding on us and the Victorian distributors for the 2021–25 regulatory determination.¹⁸ We may only vary our proposed control mechanism formulas in making the determination in response to a material change in circumstances.¹⁹ However, without affecting the content of a determination that has already

¹³ NER, cl. 6.12.3(b).

¹⁴ NER, cl. 6.2.5(a).

¹⁵ NER, cl. 6.12.3(c).

¹⁶ NER, cl. 6.2.5(b).

¹⁷ NER, cl. 6.2.6(a). The basis of the form of control is the method by which target revenues or prices are calculated e.g. a building block approach.

¹⁸ NER, cl. 6.8.1(b)(1)(i).

¹⁹ NER, cl. 6.12.3(c)(1).

been made, an F&A paper may be amended or replaced in accordance with the rules and with consultation.²⁰

Incentive schemes

Incentive schemes encourage network businesses to manage their networks in a safe, reliable manner that serves the long term interests of consumers. They provide network businesses with incentives to only incur efficient costs and to meet or exceed service quality targets. Our proposed position is to apply each of the available incentive schemes to each of the Victorian network businesses:

- Service Target Performance Incentive Scheme (STPIS)
- Efficiency Benefit Sharing Scheme (EBSS)
- Capital Expenditure Sharing Scheme (CESS)
- Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance Mechanism (DMIAM or Allowance Mechanism)
- Victoria F-factor scheme.

Our final F&A approach on the application of incentive schemes is not binding on us or the Victorian network businesses.

Application of our Expenditure Forecast Assessment Guideline

Our Expenditure Forecast Assessment Guideline²¹ is based on a reporting framework allowing us to compare the relative efficiencies of distributors. Our proposed position is to apply the guideline, including its information requirements, to the Victorian network businesses in the 2021–25 regulatory control period.

Our Guideline outlines a suite of assessment/analytical tools and techniques to assist our review of the Victorian distributors' regulatory proposals. We intend to apply the assessment/analytical tools set out in the Guideline and any other appropriate tools for assessing expenditure forecasts.²²

Our final F&A approach on the application of our Guideline is not binding.

Depreciation

When we roll forward the Victorian network businesses' regulatory asset bases (RABs) for a regulatory control period we must adjust for depreciation. Our preliminary position is to use depreciation based on forecast capex (or forecast depreciation) to establish the opening RABs as at 1 January 2026. In combination with our proposed application of the CESS this

²⁰ NER, cl 6.8.1(a)(2), 6.8.1(c)(3).

²¹ AER, *Expenditure Forecast Assessment Guideline for Distribution*, November 2013.

²² We are continuously improving the economic benchmarking techniques that are captured in our Guideline. This includes reviewing and refining our analysis of operating environment factors. See section 4 for more detail.

approach will maintain incentives for the distributors to pursue capex efficiencies. These improved efficiencies will benefit consumers through lower regulated prices.

Our final F&A position on the depreciation approach is not binding.

Dual function assets

Dual function assets are high-voltage transmission assets forming part of a distribution network. We decide whether to price dual function assets according to transmission or distribution pricing rules.

No Victorian distributor currently owns, controls or operates any dual function assets. This is because there is a framework in section 50 of the National Electricity Law for a 'declared transmission system', which has been adopted in Victoria.²³ Therefore, our decision is that we are not required to make any determination under the rules regarding dual function assets.²⁴

Consumer engagement

With the industry undergoing a period of rapid transformation, consumer engagement is becoming increasingly important in the development of proposals by network businesses. The increased focus on consumer engagement has led network businesses to commence engagement activities with consumers much earlier in the regulatory process than ever before. All distributors have already commenced consumer engagements processes.

CitiPower, Powercor and United Energy commenced their customer engagement program in early 2017 by conducting focus groups, interviews and surveys with more than 2,000 customers across CitiPower, Powercor and United Energy. The distributors conducted their first deliberative workshop in November 2017, involving 50 key energy stakeholders from Victoria, on the most likely drivers of change and the possible scenarios for the future of the network. Through 2017 CitiPower, Powercor and United Energy also conducted a joint workshop with other Victorian distributors to discuss network tariffs. Through to August 2018, CitiPower, Powercor and United Energy have conducted further customer research through:

- three forums with 40 community opinion leaders in Melbourne, Geelong and Mildura
- three deliberative workshops with 250 residential and small business customers
- 20 interviews with large customers
- 1,800 surveys of residential and small business customers
- A second network pricing forum with other Victorian distributors
- on-going meetings with retailers and large commercial and industrial customers on future network options

²³ NEL, s50.

²⁴ NER, cl 6.8.1(b)(1)(ii), cl 6.25(b).

In November 2018, CitiPower, Powercor and United Energy will release their draft proposal and draft connection policy, which will be open for comments to all customers and stakeholders. During 2019 the distributors will conduct in-depth engagement with customers and stakeholders on their draft proposal, including potential expenditure deep-dives and/or citizen juries.

Jemena's engagement program commenced in mid-2017 with research to understand customer values and how to best communicate complex electricity and regulatory concepts. Taking this feedback into account, in 2018 Jemena established a Peoples Panel of 43 residential customers across their network area. The Panel explored key themes of affordability, reliability, pricing structures and the network of the future and the Panel was provided direct input from experts across the energy industry. In August 2018 the Panel provided a set of clear recommendations for Jemena to consider in preparing its regulatory proposal. Jemena is also engaging one-on-one with business and industrial customers, and through specialised forums with other stakeholders including Councils.

Jemena expects to reconvene its Peoples Panel in February 2019 to deliberate on its draft regulatory proposal, and continue the conversation with other customer and stakeholder groups, including deep-dives. In particular, Jemena will partner with the other Victorian electricity businesses to finalise and consult on a draft tariff structures statement. This follows extensive engagement on pricing structures throughout 2018.

AusNet Services is trialling the New Reg process, which was jointly developed by the AER, Energy Networks Australia and Energy Consumers Australia. The overall vision of the New Reg process is that energy consumers' priorities should drive energy network business proposals and regulatory outcomes.²⁵

The New Reg process established a Customer Forum that is tasked with the responsibility of being a credible counterparty in negotiations with a regulated business on elements of the regulated businesses regulatory proposal. While these negotiations do not bind the AER, and AER will undertake its assessment of AusNet Services' regulatory proposal as normal, the engagement between AusNet and the Customer Forum is expected to continue into 2019, which will be after the AER makes its final decision on the F&A.

AusNet Services commenced the recruitment process for the Customer Forum in late-2017. All Customer Forum members were engaged and the Forum commenced in March 2018. Over the first half of 2018, AusNet Services held monthly workshops with the Forum and consulted with the AER to agree the scope of the negotiations between the Customer Forum and AusNet Services and associated timeframes. In August 2018, AusNet Services commenced a process of negotiations with the Customer Forum on aspects of its regulatory proposal. These negotiations will inform a draft regulatory proposal for public consultation, which will be published by AusNet Services in December 2018 alongside a draft

²⁵ AER, Energy Consumers Australia, Energy Networks Australia, New Reg towards consumer centric energy network regulation, directions paper, March 2018, p. 3.

Engagement Report. If required, the Customer Forum will be involved in a second negotiation round prior to AusNet Services' finalising its regulatory proposal.²⁶

Further information on the New Reg process is set out in detail in the directions paper²⁷, AusNet Services' Early Engagement Plan²⁸, and also a memorandum of understanding between the AER, AusNet Services and the Chair of the Customer Forum, Tony Robinson²⁹. More information about the New Reg process more broadly is available on the AER website.³⁰

Key dates for the Customer Forum pre-proposal engagement process are as follows.

Event	Date
Advocates workshop	October 2018
Draft engagement report	Early December 2018
Draft proposal	Early December 2018
Consultation on draft proposal	From December 2018

Source: AusNet Services

In addition to the Customer Forum and associated New Reg process, AusNet Services is undertaking a concurrent stream of customer research activities, including in-depth stakeholder interviews, Community Forums, Focus Groups and customer surveys. AusNet Services formed a Customer Consultative Committee in 2016, which is designed to act as a direct channel for external customer perspectives and inform decision making with AusNet Services.³¹

In its request to replace the current F&A, AusNet Services requested that we acknowledge the Customer Forum process in the F&A and provide some high level guidance regarding how this will be incorporated into our approach to F&A matters including:

- the application of the Better Regulation Guidelines, such as the Expenditure Forecast Assessment Guideline,
- the way in which the incentive schemes are applied and the development of any small scale incentive schemes, and
- proposed new services and their classification.³²

²⁶ AusNet Services, *Early engagement plan*, 2018, see: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-innovation>.

²⁷ AER, Energy Consumers Australia, Energy Networks Australia, *New Reg towards consumer centric energy network regulation, directions paper*, March 2018.

²⁸ AusNet Services, *Early Engagement Plan*, EDPR 2021-2025 Customer Forum.

²⁹ AusNet Services, AER, Tony Robinson, *Memorandum of Understanding between Australian Energy Regulator, AusNet Services, and Tony Robinson*.

³⁰ See <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-innovation>.

³¹ See: <https://www.ausnetservices.com.au/Community/Customer-Consultative-Committee>.

³² AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*,

We expect that the Customer Forum process will contribute to the development of a regulatory proposal by AusNet Services that is better aligned with consumer interests. We anticipate that the final F&A will be informed by the Customer Forum process, but will reflect the AER's position on the areas identified above. We will formally consider any inputs from the Customer Forum as part of the Draft Determination process, after AusNet Services has submitted its regulatory proposal. We are permitted to make changes to service classification in the Draft Determination and Final Determination if we consider that a material change in circumstances justify departing from the classification set out in the final F&A paper. Any input from the Customer Forum on service classification issues following publication of the final F&A on 31 January 2019 would need to satisfy this requirement.³³

³⁰ April 2018, p. 3–4.

³³ NER cl. 6.12.3(b).

1 Classification of distribution services

This chapter sets out our preliminary position on the classification of distribution services provided by the Victorian distributors in the 2021–25 regulatory control period. Service classification determines the nature of economic regulation, if any, applicable to distribution services. Applying the classification process prescribed in the NER, we may classify services so that we:

- directly control prices of some distribution services³⁴
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate some distribution services at all.

Our classification decisions therefore determine which services we will regulate and how distributors will recover the cost of providing those regulated services.

Our Electricity Distribution Ring-fencing Guideline, which came into effect in December 2016, has prompted distributors to review the classification of services that they provide. Our classification decisions will also settle the precise manner in which the ring-fencing obligations will apply to each Victorian distributor for the 2021–25 regulatory control period.³⁵ In July 2016, the *National Electricity (Victoria) Act 2005* was amended so that chapter 5A of the rules and the AER's Connection Charge Guideline apply to Victorian distributors. For these reasons, we have closely reviewed the table of distribution services at Appendix B.

The Australian Energy Market Commission (AEMC) recently made changes to the NER, following two rule change proposals from the Council of Australian Governments Energy Council and the Australian Energy Council, on contestability of energy services.³⁶ The new rule streamlines the classification provisions and requires us to develop and publish service classification guidelines by 30 September 2018. More specifically, the NER has removed the requirement for us to maintain the current service classification unless another classification is clearly more appropriate. Removing this provision provides an opportunity to improve clarity, and achieve greater consistency across jurisdictions as far as practicable. It also provides more predictability in how distribution services might be classified and service descriptions that better align with the services being provided.

The service classification guideline will not bind the AER. However, we are required to set out our reasons for any departure from the guideline to provide transparency to stakeholders in circumstances where our approach differs from that in the classification guideline.

³⁴ Control mechanisms available for each service depend on their classification. Control mechanisms available for direct control services are listed by clause 6.2.5(b) of the NER. These include caps on revenue, average revenue, prices and weighted average prices. A fixed price schedule or a combination of the listed forms of control are also available.

Negotiated services are regulated under part D of chapter 6 of the NER.

³⁵ AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

³⁶ See <http://www.aemc.gov.au/Rule-Changes/Contestability-of-energy-services>.

Consultation on the development of this guideline is ongoing. We published our draft guideline for comment in late June 2018.³⁷ Work on the new service classification guidelines has been occurring in parallel to this preliminary F&A. As such, our preliminary approach to service classification for the Victorian distributors aims to provide improved clarity, consistency across jurisdictions as far as practicable, predictability in how new distribution services might be classified, and service descriptions that better align with the services being provided. There may not be complete alignment between this preliminary F&A and the final Service Classification Guideline, to be released by 30 September 2018. We will review and address any inconsistencies prior to publishing the final F&A.

1.1 AER's preliminary position

Overall, our preliminary position is to change the classification of some Victorian distribution services for the 2021–25 regulatory control period.

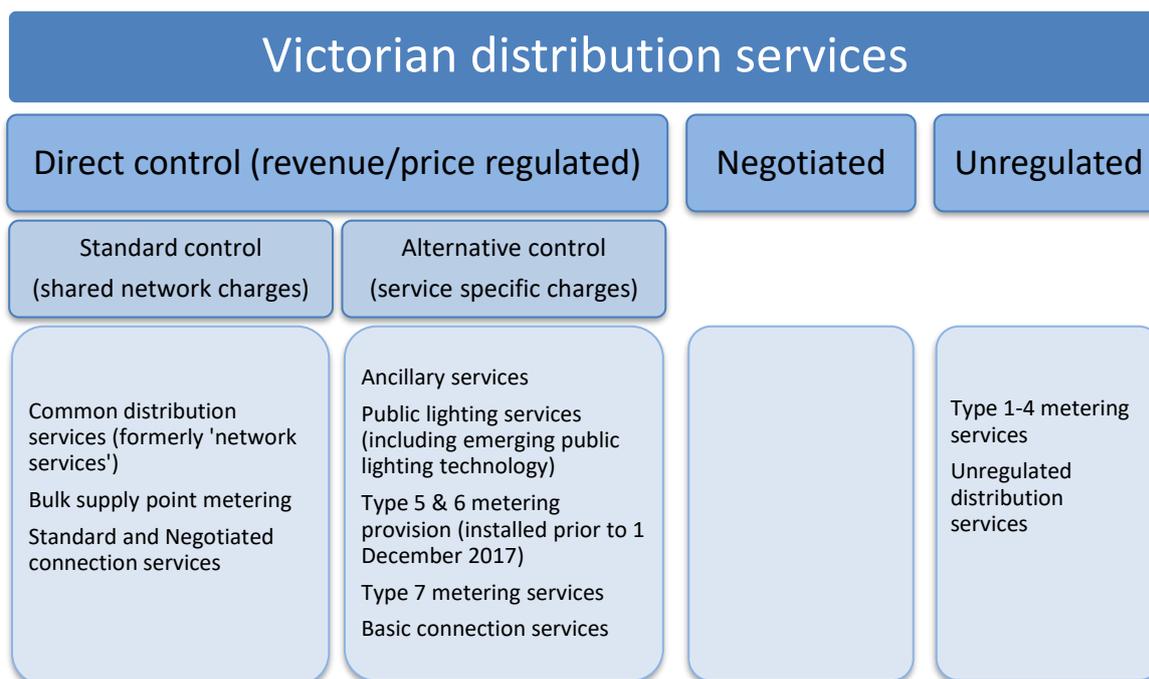
Our preliminary position is to group distribution services provided by the Victorian distributors as:

- common distribution services (formerly 'network services')
- connection services
- metering services
- network ancillary services
- public lighting services
- unregulated distribution services.

Figure 1.1 summarises our preliminary classification of the Victorian distribution services. Our assessment approach and reasons follow.

Figure 1.1 AER proposed approach to classification of Victorian distribution services

³⁷ As part of the consultation process so far for the development of the guideline, we produced an issues paper inviting submissions by interested parties. In response, we received eight submissions from industry stakeholders on a broad range of issues, which can be found at <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/distribution-service-classification-guidelines-and-asset-exemption-guidelines>.



Source: AER

1.2 AER's assessment approach

In conducting our assessment of distribution service classification, we commence on the basis that we:

- classify the service, rather than the asset³⁸ – we can only decide on service classification by reference to the service that is being provided. That is, distribution service classification involves the classification of services distributors directly supply to customers. It does not involve the classification of:
 - the assets used to provide such services
 - the inputs/delivery methods distributors use to provide such services to customers, or
 - services that consumers or other parties provide to distributors.
- classify distribution services in groups³⁹ – our general preference in service classification is to classify services in groupings rather than individually. This obviates the need to classify services one-by-one and instead defines a service cluster, that where a service is similar in nature it would require the same regulatory treatment. As a result, a new service with characteristics that are the same or essentially the same as other services within a group might simply be added to the existing grouping and hence be treated in the same way for ring-fencing purposes. This provides distributors with flexibility to alter

³⁸ The AEMC's Contestability of energy services rule change, made in December 2017, introduced a requirement for the AER to regulate 'restricted assets'. The AER does not classify assets as restricted assets; rather, the term is defined in the NER. The AER has a role only in assessing applications for exemptions from the restricted assets provisions of the NER.

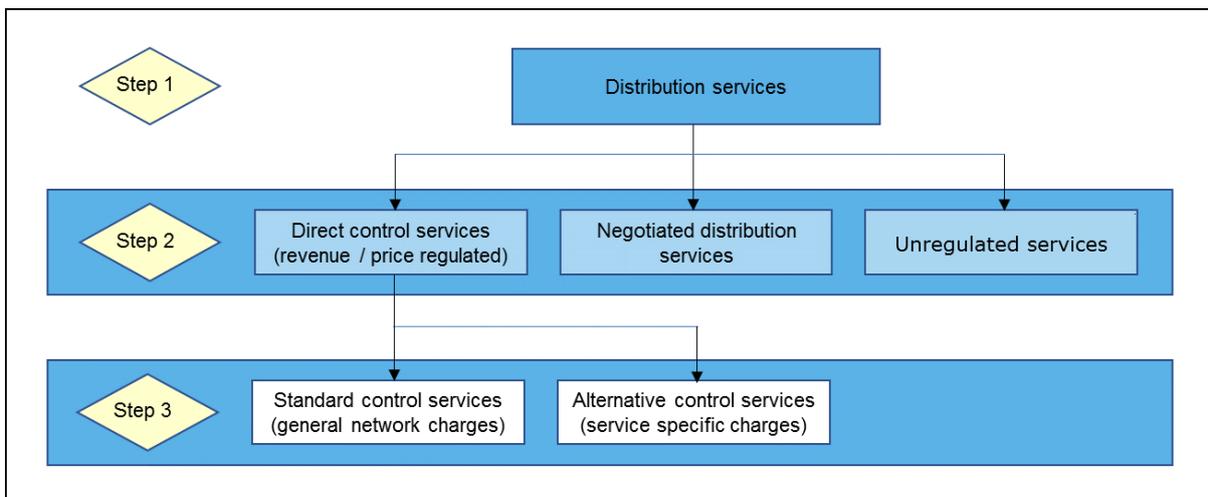
³⁹ NER, cl. 6.2.1(b).

the exact specification (but not the nature) of a service during a regulatory control period. Where we make a single classification for a group of services, it applies to each service in the group.

- We are proposing that the pricing approach for any new services, introduced within the regulatory period – which clearly fall within one of the established service groupings – should be based on a similar service within that grouping. Rather than introducing new services at any time, distributors may notify us at the time of the annual price submission, regarding the new service and the price they plan to charge.
- In some circumstances, we may choose to classify a single service because of the particular nature of that service. In addition, a distribution service that does not belong to any existing service classification may be 'not classified', and therefore treated as an unregulated distribution service for that regulatory control period. New distribution services (that are created within a regulatory control period) are also to be treated as unregulated distribution services for the remainder of that regulatory control period.

Once we group services, the NER sets out a three-step classification process we must follow. We must consider a number of specified factors at each step. Figure 1.2 outlines the classification process under the NER.

Figure 1.2 Distribution service classification process



Source: NER, chapter 6, part B.

As illustrated by figure 2:

- We must first satisfy ourselves that a service is a 'distribution service' (step 1). The NER defines a distribution service as a service provided by means of, or in connection with, a distribution system.⁴⁰ A distribution system is a 'distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system'.⁴¹
- We then consider whether economic regulation of the service is necessary (step 2). When we do not consider economic regulation is warranted we will not classify the service.⁴² If economic regulation is necessary, we consider whether to classify the service as either a direct control or negotiated distribution service.
- When we consider that a service should be classified as direct control, we further classify it as either a standard control or alternative control service (step 3).

When deciding whether to classify services as either direct control or negotiated services, or to not classify them, the NER requires us to have regard to the 'form of regulation factors' set out in the NEL.⁴³ We have reproduced these at appendix A. They include the presence or extent of barriers to entry by alternative providers and whether distributors possess market power in provision of the services. The NER also requires us to consider the desirability of consistency in the form of regulation for similar services both within and beyond the jurisdiction.⁴⁴

For services we intend to classify as direct control services, the NER requires us to have regard to a further range of factors.⁴⁵ These include the potential to develop competition in the provision of a service and how our classification may influence that potential, whether the costs of providing the service are directly attributable to the person to whom the service is provided, and the possible effect of the classification on administrative costs.

Our classification decisions determine how distributors will recover the cost of providing services.⁴⁶ Distributors recover standard control service costs by averaging them across all customers using the shared network. This shared network charge forms the core distribution component of an electricity bill. In contrast, distributors will charge a specific user benefiting from an alternative control service. Alternative control classification is akin to a 'user-pays' system. We set service specific prices to enable the distributor to recover the full efficient cost of each service from the customers using that service. At a high level, a service will be classified as an alternative control service if it is either:

- potentially contestable, and/or

⁴⁰ NER, chapter 10, glossary.

⁴¹ NER, chapter 10, glossary.

⁴² NER, cl 6.2.1(a) note.

⁴³ NER, cl. 6.2.1(c)(1); NEL, s. 2F.

⁴⁴ NER, cl. 6.2.1(c).

⁴⁵ NER, cl. 6.2.2(c).

⁴⁶ We regulate distributors by determining either the prices they may charge (price cap) or by determining the revenues they may recover from customers (revenue cap).

- it is a monopoly service used by a small number of identifiable customers on a discretionary or infrequent basis and the costs can be directly attributed to those customers.

For services we classify as negotiated, distributors and customers will negotiate service provision and price under a framework established by the NER. Our role is to arbitrate disputes where distributors and prospective customers cannot agree. Two instruments support the negotiation process (and form part of our distribution determination even where we do not classify any services as negotiated):

- Negotiating distribution service criteria—sets out the criteria distributors are to apply in negotiating the price, and terms and conditions, under which they supply distribution services. We will also apply the negotiating distribution service criteria in resolving disputes.
- Negotiating framework—sets out the procedures a distributor and any person wishing to use a negotiated distribution service must follow in negotiating for provision of the service.

In the case of some distribution services, we may determine there is sufficient competition that there is no need for us to classify the service as either a direct control or negotiated distribution service. That is, the market is sufficiently competitive, allowing customers to shop around for the best price. We refer to these distribution services as 'unregulated distribution services'. Broadly, pursuant to our Ring-Fencing Guideline, this means that while existing regulated distribution services will continue to be provided by the distributor, all unregulated distribution services or new services that come into existence within a regulatory control period must be separated from direct control services unless the distributor applies for, and receives, a waiver under the Ring-fencing Guideline.⁴⁷

1.3 Reasons for AER's preliminary position

This section sets out our preliminary service classification and reasons for the Victorian distributors' 2021–25 regulatory control period for each service group.

Appendix B contains a detailed table of our preliminary classification of Victorian distribution services.

1.3.1 Common distribution service

This service group was formerly called 'network services'. However, to avoid confusion with the defined terms in chapter 10 of the NER, we propose to rename this service group 'common distribution service'.

⁴⁷ AER, *Ring-fencing guideline electricity distribution*, October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

The common distribution service grouping is a suite of activities concerned with providing a safe and reliable electricity supply to customers.⁴⁸ Activities within the common distribution service group are intrinsically tied to the network infrastructure and the systems that support the shared use of the distribution network by customers. Customers use or rely on access to common distribution service activities on a regular basis. Providing a common distribution service involves a variety of different activities, such as the construction and maintenance of poles and wires used to transport energy across the shared network. The precise nature of activities provided to plan, design, construct and maintain the shared network may change over time. Regardless of what activities make up the common distribution service, this service group reflects the provision of access to the shared network to customers.

Our preliminary position is to classify the common distribution service group as a direct control service. Each of the Victorian distributors holds the only electricity distribution licence for their respective distribution areas.⁴⁹ Under the *Electricity Industry Act 2000* (Vic), a person is prevented from distributing and supplying electricity unless they hold a licence authorising them to do so or they are exempted from the requirement to obtain a licence.⁵⁰ These arrangements create a regulatory barrier preventing third parties from providing activities within the common distribution service group.⁵¹ Therefore, we consider that there is no opportunity for third parties to enter the market for the provision of activities classified as a common distribution service.

We must further classify direct control services as either standard or alternative control services.⁵² Our preliminary position is to retain the current standard control classification for the common distribution service. There is no potential to develop competition in the market for common distribution service activities because of the barriers outlined above.⁵³ There would be no material effect on administrative costs for us, the Victorian distributors, users or potential users by continuing this classification.⁵⁴ Further, distributors provide activities listed within the common distribution service through a shared network and therefore cannot directly attribute the costs of these services to individual customers.⁵⁵ We currently classify the common distribution service in Victoria and all other NEM jurisdictions as standard control services.⁵⁶

Victorian distributors have requested a number of new activities to be included as part of the common distribution service. We discuss each of these in turn below.

Supply abolishment of basic connection

⁴⁸ NER, Chapter 10 glossary.

⁴⁹ Licences are issued by the Essential Services Commission of Victoria.

⁵⁰ *Electricity Industry Act 2000* (Vic) s 16.

⁵¹ NER, cl. 6.2.1(c)(1); NEL, ss. 2F(a), (d) and (f).

⁵² NER, cl. 6.2.2(a).

⁵³ NER, cl. 6.2.2(c)(1).

⁵⁴ NER, cl. 6.2.2(c)(2), (3).

⁵⁵ NER, cl. 6.2.2(c)(5).

⁵⁶ NER, cl. 6.2.2(c)(4).

This activity includes the removal of a connection from the network, such as when a building is demolished and the connection is no longer required. The Victorian distributors stated that supply abolishment of basic connections has historically been classified as a standard control service.⁵⁷ They expressed concern that if provided on a cost recovery basis as an ACS service, there may be an incentive for customers to abandon sites to avoid the charge. This could pose a safety risk if network connection infrastructure is not appropriately de-energised and removed.⁵⁸ We accept the distributor's assessment of the safety risks associated with customer abandonment of energised sites in order to avoid a fee. We therefore accept this justifies classifying supply abolishment as a standard control service under the common distribution service grouping.

Bulk supply point metering

The Victorian distributors proposed that common distribution services should include 'bulk supply point metering' in common distribution services.⁵⁹ 'Bulk supply point metering' refers to metering of connection points between the transmission system and the distribution system.⁶⁰ We agree that this a service that relates to measurement of network use of system (NUoS) charges levied on all distribution customers, rather than being a 'metering service'. We have included this service under common distribution services in the service list at Appendix B.

Customer initiated asset relocations/rearrangements

The Victorian distributors proposed that network ancillary services should include 'customer initiated network asset relocations/rearrangements as a standard control service. This is ACS in other jurisdictions.⁶¹

The Victorian distributors have stated that customer initiated network asset relocations/rearrangements are covered under the Essential Services Commission (ESCV) Guideline 14.⁶² Under this Guideline and the *National Electricity (Victoria) Act 2015*, when a

⁵⁷ AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 10; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.3; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.A-1.

⁵⁸ CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.3.

⁵⁹ AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 10; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.3; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.A-1.

⁶⁰ AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 10; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.3; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.A-1.

⁶¹ AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 13; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.5; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.A-4.

⁶² Essential Services Commission Victoria, *Electricity Industry Guideline No. 14: Provision of services by electricity*

customer requests for network assets to be moved or replaced, the customer pays a capital contribution to the cost of relocating or rearranging the assets. The capital contribution may not be equal to the cost of relocating or rearranging the assets: The distributor calculates the customer capital contribution by netting off any benefits that the distributor accrues as a result of the rearrangement or relocation of network infrastructure. For example, if the distributor replaces older poles with new poles on the part of its network that has been relocated, the benefits to the distributor in terms of incremental revenue as a result of deferred replacement expenditure will be factored into the capital contribution that the customer pays.⁶³

Victorian jurisdictional arrangements remain in place and Guideline 14 continues to apply to customer initiated asset relocations and rearrangements.⁶⁴ We propose classifying this as a standard control service, and listing it as an activity under the common distribution service grouping, for the purposes of the preliminary F&A.

Recoverable works

We define recoverable works as the distributor's work to repair damage following a person's act or omission, for which that person is liable (for example, repairs to a power pole following a motor vehicle accident).

Given that these services are provided in connection with a distribution system, we consider this a distribution service. In the current regulatory control period, we did not classify this service in Victoria. Therefore, the service was unregulated.⁶⁵ This was because the cost of these works could be recovered through other avenues (e.g. under common law). However, following the introduction of our Ring-fencing Guideline, we have had cause to reconsider the classification of this service. As an unregulated distribution service, it would be subject to ring-fencing that could increase the cost of these activities.

In response to the obligations outlined in our Ring-fencing Guideline, Victorian distributors applied for and obtained ring-fencing waivers for 'emergency recoverable works'. It is our view that the scope of this activity should include all types of recoverable works, including those of an emergency nature. As a result, for the forthcoming Determination, it is our intention to include an activity as part of the common distribution service called "Works to fix damage to the network (including recoverable works caused by a customer or third party)".

It is our intention is that this service should be classified as direct control. Furthermore, as an activity under the common distribution service group, recoverable works should be classified as a standard control service. Jemena supported this position in their letter requesting to

distributors, April 2004

⁶³ Essential Services Commission Victoria, *Electricity Industry Guideline No. 14: Provision of services by electricity distributors*, April 2004, p.5.

⁶⁴ *National Electricity (Victoria) Further Amendment Act 2016*, cl.4.

⁶⁵ AER, Final framework and approach for Victorian electricity distributors - Regulatory control period commencing 1 January 2016, 24 October 2014, p.13.

replace the F&A.⁶⁶ Distributors are required to perform works to maintain or repair the shared network to ensure a safe and reliable electricity supply.

Although we propose classifying this service as a standard control service, a distributor is still expected to seek recovery of the cost of these repairs from the responsible third party where possible. The change to classification should have no net effect on distributor's costs. When the distributor recovers the cost of the repairs from a third party, the amount recovered is netted off the opex allowance, which means there is no overall cost to distribution customers. Unrecovered costs of such repairs form part of the normal allowance for repairs, consistent with the historic approach to the recovery of these costs.

Support for another distributor during an emergency event

We note that the Victorian distributors have listed a new activity under the common distribution service heading, labelled "support for another distributor during an emergency event".⁶⁷ This activity is provided in connection with a distribution system, and we consider it a distribution service. However, in the case of an emergency event, where the distributor is called upon to assist another distributor, the works performed are not on the distributor's shared network and the distributor is entitled to recover the costs of the assistance provided. While we propose to classify these activities as standard control, the distributor is still expected to seek recovery of the costs of the assistance provided.

Stand-alone power systems

AusNet Services proposed that stand-alone power systems or SAPS (also known as 'remote area power systems' or RAPS) should be treated as an input into standard control service, so that AusNet Services is able to provide this service in event of regulatory change mid-way through their next regulatory control period.⁶⁸

The regulatory treatment of stand-alone power systems as an alternative to network replacement expenditure is currently the subject of consideration by the Council of Australian Governments Energy Council (COAG EC) and the AEMC. In 2016, Western Power submitted a rule change request to the AEMC, proposing to extend the definition of the term 'distribution service' to allow network businesses the ability to island distribution customers from the network, and provide them with stand-alone power systems (such as integrated solar PV, battery, and diesel generator nanogrids or microgrids) as an alternative to replacement of network infrastructure.⁶⁹ The AEMC's Determination found that Western Power's proposed rule change require changes to laws, rules, and state and territory

⁶⁶ Jemena Electricity Networks (Vic) Ltd, *Request for a replacement Framework and Approach*, 30 April 2018, p.5.

⁶⁷ AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 10; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.3; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.A-1.

⁶⁸ AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 8.

⁶⁹ Western Power, *Rule change proposal - Removing barriers to efficiency network investment*, 8 September 2016.

instruments, including the National Electricity Law.⁷⁰ The issue has been referred to the COAG Energy Council for further consideration and is now being progressed by the AEMC (see below).

Stand-alone power systems do not satisfy the definition of a distribution service under the NER. We are therefore unable to classify this service. Further, there is currently a lot of uncertainty about what the eventual regulatory framework for SAPS will look like, and we see no benefit in seeking to pre-empt the outcome of this process by including SAPS within the common distribution service group.

Like the AEMC, we are supportive of enabling off-grid power supply.⁷¹ We anticipate that in the event of changes to the legal and regulatory framework to enable stand-alone power systems under the NEL, any necessary changes to distributor service classifications will be considered as part of transitional arrangements. On 30 August 2018, the AEMC commenced its review of regulatory frameworks for stand-alone power system, and published terms of reference for the review.⁷²

1.3.2 Network ancillary services

Network ancillary services share the common characteristics of being services provided to individual customers on an 'as needs' basis (e.g. meter testing and reading at a customer's request, moving mains, temporary supply). Network ancillary services involve work on, or in relation to, parts of the Victorian distributors' respective distribution networks. Therefore, similar to common distribution services only the relevant distributor may perform these services in its distribution area.

The above factors create a regulatory barrier preventing any party other than the Victorian distributors providing network ancillary services in their respective distribution area.⁷³ Because of this monopoly position, customers have limited negotiating power in determining the price and other terms and conditions on which the distributors provide these services. These factors contribute to the view that the Victorian distributors possess significant market power in providing ancillary services.⁷⁴

For these reasons, we consider that we should classify network ancillary services as direct control services.

Further, we intend to classify network ancillary services as alternative control services because the Victorian distributors provide these services to specific customers.⁷⁵ As such,

⁷⁰ AEMC, *Final rule determination: National electricity amendment (alternatives to grid-supplied network services) rule 2017*, 19 December 2017.

⁷¹ AEMC *Final rule determination: National electricity amendment (alternatives to grid-supplied network services) rule 2017*, 19 December 2017, p. i.

⁷² See <https://www.aemc.gov.au/market-reviews-advice/review-regulatory-frameworks-stand-alone-power-systems>.

⁷³ NEL, s. 2F(a).

⁷⁴ NEL, s. 2F.

⁷⁵ NER, cl. 6.2.2(c)(5).

the cost of each ancillary service is directly attributable to an individual customer.⁷⁶ This results in costs that are more transparent for customers.

We adopt this view even though network ancillary services do not exhibit signs of competition or potential for competition. We also note that there would be no material effect on the administrative costs to us, the distributors, users or potential users of the network.⁷⁷ This is because classifying network ancillary services as alternative control services is consistent with the current approach.

To the extent that the provision of network ancillary services becomes or may become contestable through future changes to the regulatory or contestability frameworks, our proposed alternative control classification would allow distributors to compete as a discrete price for the service is set for each network ancillary service.

Network safety services

In their letters requesting that the F&A be amended or replaced, the Victorian distributors proposed that 'site visits related to location of underground cables' should be included as a new service under the description of the network safety services group.⁷⁸

Jemena has stated that the existing dial before you dig service is desktop based and does not involve site visits.⁷⁹ However, contractors undertaking excavation work regularly request that Jemena accurately locate cables on the site and agree to fund the cost of a site visit. Jemena proposed to create a new chargeable service for this activity.⁸⁰ We have included this service as part of the network safety services service group, which is already ACS, in the services list at Attachment B.

The network safety services group includes fitting of line guards to prevent access by possums, roof rats, and other animals to power lines. Possum guards are unclassified in the 2016-20 Determinations. We see fitting of possum guards as an important part of a distributor's role in maintaining line security and safety, as possums on lines can sometimes cause outages that require a DNSP to rectify an outage. Therefore, we propose that possum guards should be treated as an activity in the network safety services group, which is classified as ACS.

Service visits

In their letters requesting that the F&A be amended or replaced, the Victorian distributors included 'service visit' in their proposed list of alternative control services. The distributors

⁷⁶ NER, cl. 6.2.2(c)(5) – this includes a small number of identifiable customers.
NER, cl. 6.2.2(c)(2).

⁷⁸ AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 12; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.6; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. 6, p. A-5.

⁷⁹ Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.6.

⁸⁰ Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.6.

requested this service in order to recover the costs incurred when the distributor sends out a service truck to investigate an issue at a customer's request, only to find that the issue does not relate to the mis-operation of the distributor's equipment or infrastructure.⁸¹ The result is a 'wasted truck visit'.

A wasted truck visit is not a service in itself, but is rather an activity that may take place in the course of delivering a distribution service. We therefore propose not to classify this as a service, but consider that it should be listed as a chargeable item, it in the context of delivering other classified services.

Charging for these sorts of wasted truck visits should take place on the basis of the service that the distributor is attempting to provide. This charge should appear as a line item in the distributor's price list for alternative control services. For example, a distributor might send a truck to a customer's premises to perform an alternative control metering service and find that no one is at home and the service cannot be performed. In this case, the distributor can charge for that truck visit on an ACS basis because it occurred in the course of performing an alternative control service.

In another example, the distributor might send a truck to a customer's premises after receiving a complaint about a power outage or power quality issue. The distributor may do this based on a legitimate concern that the distributors' network may be the source of the problem, only to find on arrival that the issue is on the customer side of the connection point. In this case, the cost of this truck visit should be recovered through DUoS charges because the wasted truck visit occurred as part of the distributor performing common distribution services.

In our Determinations for the 2016-20 regulatory control periods for Victorian distributors, we classified "fault response - not distributor's fault" and "wasted attendance - not distributor's fault" as alternative control services.⁸² We recognise that our proposed approach to service truck visits represents a change in our approach to the previously approved regulatory treatment of wasted truck visits.

We propose to treat truck visits as an activity used in delivering another classified service, rather than a service in and of itself. This means that where a distributor is called out by a customer to inspect a suspected issue with the shared network, the distributor will not be able to charge the customer if they find that the cause of a fault or electrical issue is a customer's assets, not the network assets. This is because this truck visit would be considered an activity under 'common distribution services' (i.e. repair to the network), which is a standard control service. We recognise that this may cause issues for distributors, as they will be unable to deter customers from making spurious complaints by charging the

⁸¹ AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 11; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.6.

⁸² AER, *AusNet Service Distribution Determination Final Decision - Attachment 13*, May 2016 p. 23; AER, *Powercor Final Decision 2016-20 - Attachment 13*, p. 13-21; AER, *United Energy Distribution Determination Final Decision - 2016-2020*, May 2016, p. 13-21; AER, *Jemena Distribution Determination Final Decision - 2016-2020*, p. 13-21; AER, *CitiPower Distribution Determination Final Decision - 2016-2020*, p. 13-21.

customer for a wasted truck visit. However, we think that removing a wasted truck visit charge will also remove potential disincentives for customers to report legitimate network issues, which would otherwise be disadvantageous to network reliability and safety.

Watchman lights and security lights

Watchman lights and security lights are public lighting used to improve security, such as to illuminate a customer's premises. Security lights that are mounted on distribution assets are a distribution service. The service involves construction, relocation of distribution assets (where necessary), operation and maintenance, and billing to customers, such as local councils. In many cases, security lights are inherently tied to the network.

We intend to classify watchman and security lighting as a direct control service and further, as an alternative control service.

DNSPS are in a unique position to provide security lighting when security lighting is affixed to a distribution network pole.⁸³ Other parties would need access to poles and easements to hang security lighting assets in some circumstances. Similar to network services, ownership of network assets restricts the operation, maintenance, alteration or relocation of public lighting services to the Victorian distributors.⁸⁴ Based on this consideration, we propose to classify watchman and security lights as a direct control service.

As direct control services, we must further classify watchman and security lighting as either standard control or alternative control services.⁸⁵ Our preliminary position is to classify security and watchman lighting as an alternative control service for the following reasons:

- classifying security and watchman lighting services as alternative control services provides scope for third parties and new entrants to provide security and watchman lighting services.⁸⁶
- the Victorian distributors can directly attribute the costs of providing watchman and security lighting services to a specific set of customers. This includes local councils, large customers, and other government agencies.⁸⁷

We therefore propose to change the classification of installation, repair and maintenance of security and watchman lighting from unclassified to an alternative control service.

1.3.3 Connection services

A connection service refers to the services a distributor performs in order to:

- connect a person's home, business or other premises to the electricity distribution network (premises connection)

⁸³ NEL, s. 2F(d).

⁸⁴ NEL, s. 2F(a)(d).

⁸⁵ NER, cl. 6.2.2(c).

⁸⁶ NER, cl. 6.2.2(c)(1).

⁸⁷ NER, cl. 6.2.2(c)(5).

- extend the network to reach a person’s premises (extension).
- get more electricity from the distribution network than is possible at the moment (augmentation);

In 2016, the Victorian Government required distributors to implement chapter 5A of the NER.⁸⁸ To align service classifications with the new arrangements and connection charge policies, Victorian distributors request that connection services be redefined and reclassified in the F&A.⁸⁹

In past regulatory determinations for distributors, our classification of connection services has largely followed the jurisdictional approaches and we have not sought to align connection services across the jurisdictions.

In its request to replace the current F&A, Jemena proposed that the services and service descriptions of connection services be aligned to those categories outlined in chapter 5A of the NER.⁹⁰ Service classification for Victorian distributors in the 2016-20 Determinations defined three types of connections: two routine types of connections for customers up to 100 amps, and customers above 100 amps, as well as connections requiring augmentation.⁹¹ With the adoption of the connections rules in Chapter 5A of the NER, we are moving to defining connections in terms of 'basic', 'standard', or 'negotiated'. In addition, 'non-standard connections' and 'enhanced connection services' are used to describe other less frequently requested types of connections. This approach allows better alignment between the classification of connection services, Chapter 5A of the NER, our Connection Charge Guideline under Chapter 5A, and the distributor's connection policies.

Basic connections

Our proposed approach is to classify basic connections as direct control and further, as an alternative control service for the 2021-25 regulatory period. This is consistent with the classification in the 2016-20 Determinations for Victorian distributors, where routine connections were ACS (both for customers with connections up to and above 100 amps).⁹²

Basic connection services are connection services for retail customers under the following circumstances:

⁸⁸ National Electricity (Victoria) Further Amendment Bill 2015.

⁸⁹ CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p.1; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.1.

⁹⁰ Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. 3.

⁹¹ AER, *AusNet Service Distribution Determination Final Decision - Attachment 13*, May 2016 p. 20; AER, *Powercor Final Decision 2016-20 - Attachment 13*, p. 13-17; AER, *United Energy Distribution Determination Final Decision - 2016-2020*, May 2016, p. 13-18; AER, *Jemena Distribution Determination Final Decision - 2016-2020*, p. 13-18; AER, *CitiPower Distribution Determination Final Decision - 2016-2020*, p. 13-18.

⁹² AER, *AusNet Service Distribution Determination Final Decision - Attachment 13*, May 2016 p. 20; AER, *Powercor Final Decision 2016-20 - Attachment 13*, p. 13-17; AER, *United Energy Distribution Determination Final Decision - 2016-2020*, May 2016, p. 13-18; AER, *Jemena Distribution Determination Final Decision - 2016-2020*, p. 13-18; AER, *CitiPower Distribution Determination Final Decision - 2016-2020*, p. 13-18.

- either: (1) the retail customer is typical of a significant class of retail customers who have sought, or are likely to seek, a basic connection service, or; (2) a retail customer that is, or proposes to become, a micro-embedded generator.⁹³
- the provision of the service requires minimal or no augmentation of the distribution network.
- a model standing offer has been approved by the AER for providing that service as a basic connection service.

A new residential property owner having their house connected to the network with minimal or no augmentation is a typical example of a basic connection service. This type of connection request is common to anyone wanting to connect to the network to use electricity and therefore we consider that we should directly regulate the price of these services.

We consider that the current alternative control classification for basic connection services is appropriate for the following reasons:

- There are barriers to market entry. Distributors approve access and materials connected to their network infrastructure.
- The cost of providing the service can be directly attributed to a specific customer. As there is no need for an augmentation or extension in performing a basic connection service, the cost revenue test does not need to be applied.

Standard connections

Our proposed approach is to classify standard connections as direct control and further, as a standard control service. This is consistent with the classification in the 2016-20 Determinations for Victorian distributors, where new connections requiring augmentations were performed as a standard control service.⁹⁴ A standard connection service is a connection service (other than a basic connection service) for a particular class (or sub-class) of connection application, and for which a model standing offer has been approved by the AER.⁹⁵ What differentiates this service from a basic connection is that standard connections typically require a network extension or a network augmentation. This means that it is subject to a cost revenue test under the AER's Connection Charge Guideline.

We consider that the current standard classification for standard connection services is appropriate. There is no potential for the development of competition in providing this service. Where a new connection requires an extension or augmentation of the shared network, there is potential benefit for other customers on the distributor's network. To ensure that the distributor only recovers efficient costs, standard connections are subject to a cost

⁹³ NER cl. 5A.A1 defines a 'micro-embedded generator' as a retail customer who owns or operators an embedded generator that is connected to the network Australian Standard AS 4777 (Grid connection of energy systems by inverters).

⁹⁴ AER, *AusNet Service Distribution Determination Final Decision - Attachment 13*, May 2016 p. 20; AER, *Powercor Final Decision 2016-20 - Attachment 13*, p. 13-17; AER, *United Energy Distribution Determination Final Decision - 2016-2020*, May 2016, p. 13-18; AER, *Jemena Distribution Determination Final Decision - 2016-2020*, p. 13-18; AER, *CitiPower Distribution Determination Final Decision - 2016-2020*, p. 13-18.

⁹⁵ NER cl. 5A.A1

revenue test. This test determines the customer connection charge by subtracting the net present value of the new customer's future DUoS payments over a 30 year period (or 15 years for businesses) from the upfront cost of the connection.⁹⁶

Negotiated connections

Our approach is to classify negotiated connections as a direct control service, and further, as a standard control service. Negotiated connection services were not classified in the 2016-20 Determinations for Victorian distributors.

Negotiated connections are connection services that are delivered under the negotiating provisions in Chapter 5A of the NER. Connection services for larger customers, who require special connection requirements, are typically delivered on a negotiated basis. These services often require some form of augmentation to the network in order to provide the connection service requested by the customer.

We propose to include connections under Chapter 5 of the NER in negotiated connections. Chapter 5 of the NER generally regulates connection of generators to the transmission network. However, at times, connection of other large loads to the distribution network can take place under Chapter 5.⁹⁷ While the distributors already provide connection services under Chapter 5, the regulatory treatment of these connection services was not explicit in the 2016 Determination for Victorian distributors.

We consider that a standard control service classification is appropriate for the following reasons:

- Distributors retain some market power as they have control over whether or not a particular connection is contestable.
- In Victoria, a standard control classification for this service is not a constraint on competition. A rebate, equal to the amount of the DUoS calculation that goes into the RAB, is provided to customers that obtain third party connections. The Victorian DNSPs have submitted that the jurisdictional requirements under the Essential Services Commission's Guideline 14 enable the DNSPs to provide a rebate (equal to the present value of the incremental DUoS revenue that the DNSP will earn from the new connection) to customers that choose to source connection works from contestable service providers.⁹⁸ In responding to this preliminary F&A, the Victorian DNSPs should set out how Guideline 14 applies to their provision of connection services and how this is connected to the rebate that facilitates contestability of connections services.
- A classification of standard control is also appropriate because connection costs are based on the full cost of providing the service, subject to a cost revenue test that takes into account future revenue earned from tariffs paid by a connecting customer. Application of the cost revenue test means a connecting customer will eventually pay the

⁹⁶ AER, Connection Charge Guideline,

⁹⁷ NER, cl. 5.1.2(a)(1).

full cost of their connection and make a contribution to shared network costs. This payment, however, will occur through both ongoing payment of distribution tariffs and, if required, a capital contribution. All existing customers will benefit from the connection of new customers even though, at first, those costs will not have been fully recovered from the connecting customers.

Jemena, CitiPower/Powercor and United Energy suggested that negotiated connection charges should remain a standard control service.⁹⁹ At present, negotiated connections are a standard control service in Victoria, and capital contributions are calculated according to our Connection Charge Guideline¹⁰⁰ and outlined in the Victorian distributors' respective Connection Policies.¹⁰¹

Connection application and management services

Our proposed approach is to classify connection application and management services as direct control, and further, as alternative control services.

Connection management services are activities associated with connections, such as:

- requests for premises de-energisation or re-energisation
- temporary connections (such as a builders connection)
- customer overhead line replacements or re-location
- customer requested upgrades to their connection (such as undergrounding)
- calculation of site specific loss factors when required under the NER
- assessing applications to undertake network asset relocations
- undertaking design work to assess connection costs and technical studies to assess network impacts of new connections
- site inspections associated with new connections, and
- registered participant support services associated with connections under Chapter 5 of the NER.

The Victorian distributors have included 'embedded networks' in their letters requesting that the F&A be amended or replaced.¹⁰² We propose to include embedded network management as an activity under the connection application and management services group. Victorian DNSP activities in relation to embedded networks chiefly involve ensuring

⁹⁹ CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p. 8; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. A-8.

¹⁰⁰ AER, *Connection Charge Guideline 2012*, p.39.

¹⁰¹ CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p. 8; Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. A-8.

¹⁰² AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 15; CitiPower/Powercor and United Energy, *Request to replace the 2014 framework and approach paper*, 30 April 2018, p. 7. Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p.8.

abolishment of NMIs is performed correctly (when customers become part of an embedded network), coordinating bulk abolishment of requested sites and removal of metering, and checking the designs of the embedded network operator to ensure that customers who want to maintain a stand-alone NMI are not mistakenly incorporated into the embedded network or disconnected from supply.

We consider that an alternative control service classification is appropriate for the following reasons:

- There are barriers to market entry. Distributors approve access and materials connected to their network infrastructure.
- The service is provided to an identifiable customer or subset of customers.

In its letter requesting to replace or amend the F&A for Victorian distributors, Jemena proposed that temporary connections, which are connections provided for a short period after which the connection is removed, should be distinguished as a stand-alone service.¹⁰³ We have grouped this service under connection management and application services in the services list at Appendix B. We welcome submissions from stakeholders on this approach.

Enhanced connections

Our proposed approach is to classify enhanced connection services as direct control, and further, as an alternative control service.

Enhanced connection services cover activities to provide customers with a higher standard of electricity supply that exceeds the minimum technically feasible standard. These include services where customers request higher levels of reliability or three phase electricity, where customers request the construction of a second connection from the distribution network to the customer (a reserve feeder), or where a customer requests a supply enhancement.

We consider that an alternative control service classification is appropriate for the following reasons:

- There are barriers to market entry. Distributors approve access and materials connected to their network infrastructure.
- The service is provided to an identifiable customer or subset of customers.

Enhanced connection services and reserve feeder construction were classified as negotiated services in the Determination for Victorian DNSPs in the 2016-21 regulatory control period. Customer-requested supply enhancements were unclassified. For the reasons above, we consider that an alternative control service classification is more appropriate.

Community network upgrades

In its letter requesting that the F&A be amended or replaced, AusNet Services proposed a new connection related service: 'connection services provided to multiple parties under a

¹⁰³ Jemena Electricity Networks, *Request for a replacement Framework and Approach*, 30 April 2018, p. 4.

common process' or 'community network upgrades'. When community groups seek to connect multiple behind-the-meter solar PV to the network as part of a broader community energy project, AusNet Services proposed that these community groups should be treated as a single, large connection, rather than multiple basic connections. Where connection of new behind the meter solar PV necessitates network augmentation, AusNet Services has proposed that the cost of network augmentation could be spread over all connecting parties within the community group.¹⁰⁴

This proposed service raises a wider challenge associated with the integration of distributed energy resources into the network. As more customers connect behind the meter distributed energy resources (DER) such as rooftop solar PV to the low voltage network, the capacity of that part of the network to accept increasing solar exports may become constrained over time. Solutions to network constraints as a result of increased solar exports can include increasing the capacity of the network through augmentations, or it can include limiting solar exports. Increasing penetration of distributed energy resources means that distributors across multiple jurisdictions are facing issues associated with DER-driven network constraints for the first time, and are adopting a variety of augmentation or export-control based strategies.¹⁰⁵

We support the development of a long-term approach to managing DER-induced network constraints in a way that delivers customers the services that they demand, including allowing customers the ability to invest in their own DER and deliver services to the grid, while avoiding inefficient network expenditure.

However, we are concerned that AusNet Services' proposed approach may not be consistent with the current energy rules for the following reasons. First, Chapter 5A of the NER prevents a distributor from charging a capital contribution to a retail customer for augmentations to the network where:

- the application is for a basic connection service, or
- the customer's request does not exceed a relevant threshold set by the distributor's connection policy.¹⁰⁶

The intention of this rule is to ensure that retail customers are not charged for deep system augmentation.¹⁰⁷ This means that distributors cannot charge residential DER customers for network augmentation under the Rules.

¹⁰⁴ AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 9, p. 16.

¹⁰⁵ For example, these issues are discussed in relation to SA Power Networks in the submission by the Consumer Challenge Panel 14's Advice - Response to SAPN's approach to the challenges of the high penetration of embedded generation, and to SA Power Networks' response: <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25/proposal>.

¹⁰⁶ This threshold, which is set by the distributor, should have regard to the average size of the customers connected to the network, and whether the network is classified as CBD, urban, long rural, or short rural feeders. In most circumstance the AER considers that these thresholds would be 25 kVa on single wire earth return (SWER) lines or 100 amp 3 phase connections. See AER, *Connection charge guideline for electricity retail customers*, June 2012, p. 8-9.

¹⁰⁷ NER, cl.5A.E.1.

Second, each member of the 'community group' would be individual connections with individual National Metering Identifiers (NMI)s. We do not believe that PV installations can be considered as a single, larger connection, as they are not connected to any single connection point.

Third, there are also equity considerations associated with this proposal. In most cases, community groups will not be the first residential DER to connect to that part of the network. Pre-existing DER customers, who have already connected on an individual basis, would also contribute to the total flow of solar exports on a given part of the network, and hence to the presence of a network constraint. Under this proposal, DER customers connecting as a community group would therefore be paying not just for their impact on the network, but also for the impact of any pre-existing DER customers. Moreover, were a community group to connect multiple DER customers under a single project and pay for a network augmentation collectively, other DER customers that subsequently connect to the network as individuals may also benefit from the removal of the original network constraint by the community group. But would not be required to personally contribute to the cost of the augmentation under Chapter 5A of the NER. In short, the proposed service would mean that DER customers connecting collectively as community groups would be subject to higher connection costs than DER residential customers connecting on an individual basis.

Fourth, the connections framework under Chapter 5A and Chapter 5 of the NER has been established to ensure an open access connections regime. Broadly speaking under the NER, parties have a right to negotiate connection to the transmission or distribution network, but they have no guarantee that they can export all of their output into the grid at any time (as distinct from a 'firm access' connections regime). Under AusNet Services' proposed service, a community group may pay for the cost of a network augmentation, but they would have no guarantee of being able to export their energy in the future. Other customers on the same network could choose to add more DER to the local network, after the community group has paid for a network augmentation, and in doing so create a new constraint. Were the AER to exempt community groups from the requirement in Chapter 5A that residential customers should not pay for network augmentations, the connecting parties would run the risk of having their solar exports constrained in the future even after they have paid for an augmentation.

We will not classify AusNet Services' proposed 'community network upgrades' services. We recognise that issues associated with increasing penetration of DER on the network are creating challenges associated with network constraints. The capability of the regulatory framework to address this issue is actively being considered outside of this preliminary F&A.¹⁰⁸

1.3.4 Metering services

All electricity customers have a meter that measures the amount of electricity they use.¹⁰⁹

¹⁰⁸ AEMC, Promoting efficiency investment in the grid of the future, 26 July 2018, pp. iv-v.

¹⁰⁹ All connections to the network must have a metering installation (NER, cl. 7.3.1A(a)).

On 26 November 2015, the AEMC made a final rule to open up competition in metering services and give consumers more opportunities to access a wider range of metering services.¹¹⁰ The new arrangements commenced on 1 December 2017 and required changes to the NER and the National Electricity Retail Rules (NERR).¹¹¹ Following the AEMC rule change to introduce competition in metering and related services, the Victorian Government deferred metering competition in Victoria through an Order-In-Council.¹¹² Consequently, Victorian distributors are exclusive providers of metering services to residential and small business customers consuming up to 160 MWh of electricity per annum. Our proposed classification of metering services in Victoria is consistent with our classification approach in the 2016-20 Determination.

Type 1 to 4 metering services

Type 1 to 4 meters provide a range of additional functions compared to other meters. In particular, these meter types have a remote communication ability. Type 1 to 4 meters are competitively available¹¹³ and we do not currently regulate them in Victoria or in most other jurisdictions—they are not classified and therefore are unregulated distribution services and our preliminary position is for them to remain so. Under the Victorian Government Order-In-Council, new or replacement meters for small customers do not have to be type 4 meters.¹¹⁴ In other jurisdictions, a metering coordinator must ensure that all new or replacement meters for small customers are type 4 meters, unless a customer refuses a type 4 meter.¹¹⁵

Type 5 and 6 metering services

Victorian distributors are monopoly providers of type 5 (interval) and type 6 (accumulation) meters and have the role of metering coordinator, metering provider, and metering data provider for AMI meters.¹¹⁶ In 2006, the Victorian Government initiated a roll-out of smart meters to all households and small businesses with electricity use of up to 160 MWh per annum under the Advanced Metering Infrastructure (AMI) program. AMI meters can be remotely read and can be remotely turned on and off. Under a Victorian government derogation, AMI meters are classified as type 5-6 meters.¹¹⁷

Type 5-6 metering services, including services for AMI meters as specified under the Victorian Government Order-In-Council, as alternative control services. Prices for Victorian distributors (or local network service providers, LNSPs) are provided under Chapter 6 and

¹¹⁰ AEMC, *Competition in metering services information sheet*, 26 November 2015.

¹¹¹ AEMC, *Competition in metering services information sheet*, 26 November 2015.

¹¹² Victorian Government Order-In-Council, *No. S 346*, Thursday 12 October 2017.

¹¹³ NER, cl. 7.2.3(a)(2) and 7.3.1.A(a)).

¹¹⁴ Victorian Government Order-In-Council, *No. S 346*, Thursday 12 October 2017, cl. 5.

¹¹⁵ NER cl. 7.8.3 and 7.8.4

¹¹⁶ Victorian Government Order-In-Council, *No. S 346*, Thursday 12 October 2017, cl. 3 and 4 and 9.

¹¹⁷ Victorian Government Order-In-Council, *No. S 346*, Thursday 12 October 2017, cl. 2(b).

Chapter 11 of the NER.¹¹⁸ Prices are also set with references to the Advanced Metering Infrastructure (AMI Tariffs) Order-In-Council of 2013.¹¹⁹

Type 7 metering services

Type 7 metering services are unmetered connections with a predictable energy consumption pattern (for example, public lighting connections). Such connections do not include a meter that measures electricity use. Charges associated with type 7 metering services relate to the process of estimating electricity use. For example, the distributor estimates public light usage using the total time the lights were on, the number of lights in operation and the light bulb wattage. The Victorian distributors are the monopoly providers of type 7 metering services in Victoria.

We therefore consider that there is no potential to develop competition in the provision of type 7 metering services.¹²⁰ We intend to classify type 7 metering services as direct control services and further, as alternative control. This is a continuation of the current classification of type 7 metering services.¹²¹

Auxiliary metering services (type 5 and 6 including smart meters) where the distributor remains responsible

The Victorian distributors also provide a range of metering related services to specific customers on request. Examples include requested meter tests, and additional meter reads or equipment alterations. As AMI smart meters are included in type 5 meters in Victoria, this service also includes remote de-energisation and re-energisation of metering.

We consider that there is no potential to develop competition for type 5-6 auxiliary metering services, and that the services provided are delivered to an identifiable customer.¹²² We intend to classify type 5-6 auxiliary metering services where the distributor remains responsible as direct control services, and further, as alternative control. This is a continuation of the current classification of type 5-6 auxiliary metering services.¹²³

¹¹⁸ Victorian Government Order-In-Council, No. S 346, Thursday 12 October 2017, cl. 9.

¹¹⁹ Victorian Government Order-In-Council, No. S 216. 18 June 2013.

¹²⁰ NER, cl. 6.2.2(c)(1).

¹²¹ AER, *Final decision AusNet Services distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-16; AER, *Final decision CitiPower distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-15; AER, *Final decision Powercor distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-15; AER, *Final decision United Energy distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p.13-15; AER, *Final decision Jemena distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-15.

¹²² NER, cl. 6.2.2(c)(1) and 6.2.2(c)(5).

¹²³ AER, *Final decision AusNet Services distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-17; AER, *Final decision CitiPower distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-15; AER, *Final decision Powercor distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-15; AER, *Final decision United Energy distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p.13-15; AER, *Final decision Jemena distribution determination 2016 to 2020, Attachment 13 - Classification of services*, May 2016, p. 13-15.

1.3.5 Public lighting

The Victorian distributors operate and maintain the majority of public lighting systems throughout Victoria. The distributors provide these services on behalf of local councils and government departments responsible for public lighting in Victoria, as required under clause 10 of their respective electricity distribution licences.¹²⁴

The NER does not define public lighting services, however they are defined in the Victorian Public Lighting Code which is administered by us.¹²⁵ Further, we have consistently defined public lighting services in other distribution determinations as:

- the operation, maintenance, repair and replacement of public lighting assets
- the alteration and relocation of public lighting assets, and
- the provision of new public lighting.¹²⁶

We also propose to include emerging public lighting technology as part of the public lighting services group. Emerging public lighting technology relates to luminaires that the Victorian distributors do not provide at the time of our distribution determination. LED public lighting is an example of emerging public lighting technologies. However, emerging public lighting technology may become available during the 2021–25 regulatory control period. A distinction must also be made for Greenfield sites, such as new housing estate developments.

Greenfield sites are contestable under the Victorian Public Lighting Code.¹²⁷ That is, estate developers can procure and construct any public lighting asset from any source. Distributors need not be involved in this procurement process other than to ensure the assets can be technically integrated into the electricity network.

We intend to classify public lighting (including emerging public lighting technology) as a direct control service and further, as an alternative control service. Our reasons follow.

While the Victorian distributors do not have a legislative monopoly over these services, a monopoly position exists to some extent.¹²⁸ This is because the Victorian distributors own the majority of public lighting assets.¹²⁹ That is, other parties would need access to poles and easements to hang their own public lighting assets. Similar to common distribution

¹²⁴ See: <https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-licences-and-exemptions/electricity-and-gas-licences#tabs-container2>.

¹²⁵ See: http://www.esc.vic.gov.au/Energy/Distribution/RI_FinalPublicLightCodeFollow04ReviewNCM_Apr05.

¹²⁶ , *Final framework and approach for Victoria*, October 2014, p. 42; AER, *Final framework and approach for TasNetworks*, July 2017, p. 28.

¹²⁷ Essential Services Commission Victoria, *Public lighting code, version 2*, December 2015.

¹²⁸ NEL, s. 2F(d).

¹²⁹ NEL, s. 2F(a).

services, ownership of network assets restricts the operation, maintenance, alteration or relocation of public lighting services to the Victorian distributors.¹³⁰

Based on the above analysis, our preliminary position is to classify public lighting services, including emerging technology, as direct control services.¹³¹ This is consistent with public lighting's current classification.

As direct control services, we must further classify public lighting services as either standard control or alternative control services.¹³² Our preliminary position is to classify public lighting as an alternative control service for the following reasons:

- classifying public lighting services as alternative control services provides scope for third parties and new entrants to provide public lighting services for new public lighting assets.¹³³
- classifying public lighting services as alternative control services may encourage other potential service providers to enter the market in the future— if the Victorian Government implements a contestability regime. In the meantime, an alternative control classification supports the National Electricity Objective by ensuring distributors provide safe and reliable public lighting services to the community.¹³⁴
- there would be no material effect on administrative costs to us, the Victorian distributors, users or potential users. This is because we are retaining the current classification.¹³⁵
- the Victorian distributors can directly attribute the costs of providing public lighting services to a specific set of customers. This includes local councils and other government agencies.¹³⁶

In the 2016-20 regulatory control period, alteration and relocation of distributor public lighting assets, and new public lights are negotiated services. New lighting types not subject to a regulated charge, and new public lighting at greenfield sites are unclassified. For the reasons listed above, we consider that there is sufficient basis to move away from the previous classifications, so that public lighting services in Victoria are classified as alternative control services for the 2021-25 regulatory control period.¹³⁷

1.3.6 Unregulated distribution services

Unregulated distribution services is the term we use to describe distribution services which we have not classified as either direct control or negotiated services.¹³⁸ These services are

¹³⁰ NEL, s. 2F(a)(d).

¹³¹ NER, cl. 6.2.1.

¹³² NER, cl. 6.2.2(c).

¹³³ NER, cl. 6.2.2(c)(1).

¹³⁴ NER, cl. 6.2.2(c)(1).

¹³⁵ NER, cl. 6.2.2(c)(2).

¹³⁶ NER, cl. 6.2.2(c)(5).

¹³⁷ NER, cl. 6.2.2(c)(3).

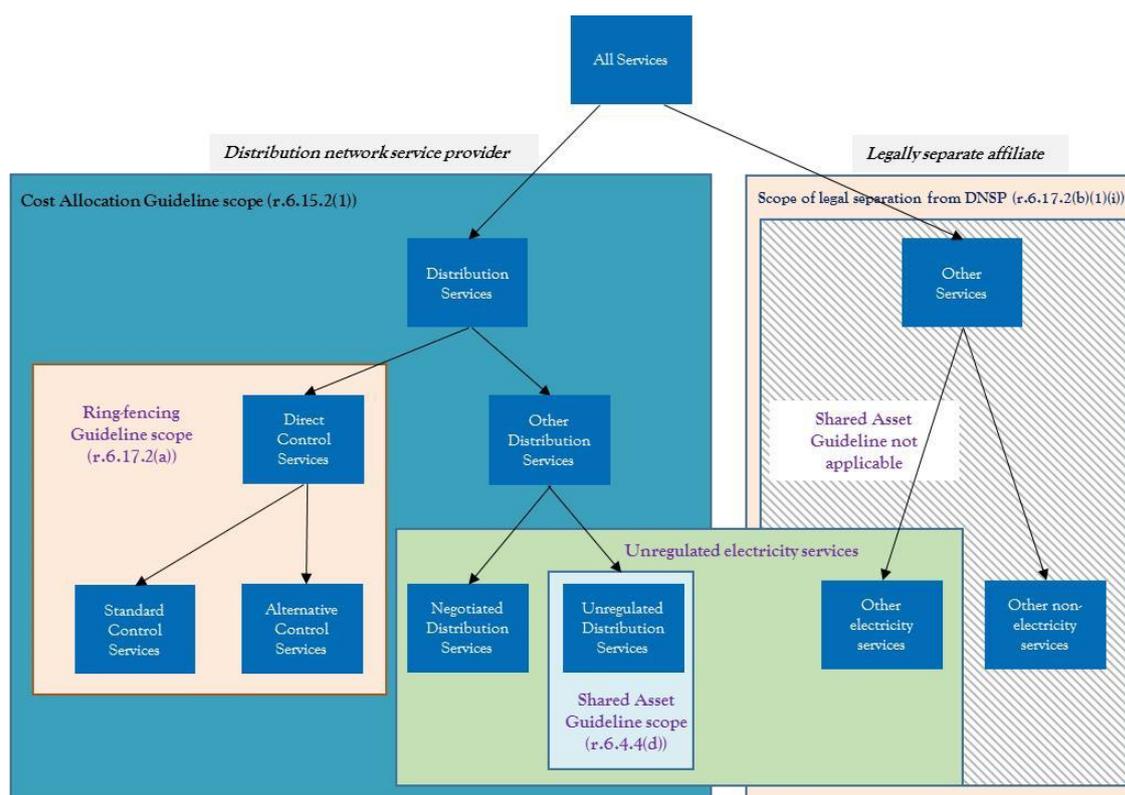
¹³⁸ AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, p. 13.

provided on an unregulated basis and are potentially provided by other service providers in a competitive market. This group of services is particularly important as the number and types of services offered by distributors is growing and changing.

In October 2017, we published the amended Electricity Distribution Ring-fencing Guideline.¹³⁹ Our Ring-fencing Guideline interacts with a number of regulatory instruments, including our service classification decisions. Specifically, our service classification decisions have an impact on how the ring-fencing obligations apply to each distributor for its next regulatory control period.¹⁴⁰ Under our Ring-fencing Guideline, unregulated distribution services are subject to functional and accounting separation from direct control services. This removes the potential risk of a distributor benefitting from its privileged access to network information to gain a competitive advantage.

Figure 1.3 illustrates the interrelationship between service classification and ring-fencing obligations. Essentially, a distributor may only provide distribution services and affiliated entities may provide other electricity services. For the purposes of this preliminary F&A, we are not addressing interactions with other regulatory frameworks in detail as these are set out in the explanatory statement to the Ring-fencing Guideline.¹⁴¹

Figure 1.3 Distribution services linkage to ring-fencing



Source: AER

¹³⁹ AER, *Ring-fencing guideline electricity distribution*, October 2017.

¹⁴⁰ AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13–16.

¹⁴¹ AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13–16.

Compliance with our Ring-fencing Guideline became mandatory on 1 January 2018. Distributors, when considering what unregulated distribution services they offer, should refer to the examples contained in the explanatory statement to the Ring-fencing Guideline¹⁴² and their unregulated revenue streams. For example, a distributor may earn additional revenue from (for example) NBN Co., by permitting NBN Co. to hang its wires from distribution network poles. Similarly, some other access to a network asset that forms part of the regulatory asset base (RAB) may be rented to a third party. We describe these as "activities related to 'shared asset facilitation' of distributor assets" under the common distribution service grouping and the revenue derived is treated in accordance with the shared asset guideline.

Transmission network support

In its letter requesting that the F&A be amended or replaced, AusNet Services proposed a new unregulated service, 'Transmission Network Support'. AusNet Services is sometimes requested to provide network support to the transmission network. For example, under an informal agreement with AEMO, AusNet Services currently switches off zone substation capacitors during light load on the transmission network. Low power flow on the transmission network can lead to high voltage that can exceed defined operating limits. Switching off capacitors at zone substations within the distribution network can help reduce voltages on the transmission network by increasing the level of reactive power that is drawn from the transmission network. In the 2018 Victorian Annual Planning Report for transmission, AEMO stated that it has managed high transmission system voltages following the closure of the Hazelwood Power Station through a temporary arrangement with distributors to switch off a total of 350 MVar reactive power of distribution substation capacitors.¹⁴³ While DNSPs may have provided this service on an ad hoc basis historically, AEMO appears to be requiring this service to a greater extent than it has in the past as a result of the closure of the Hazelwood Power Station.

At present AusNet Services does not receive revenue in respect to this service. AusNet Services intends to formalise and charge for this service as an unregulated service. AusNet Services considers that revenue earned in this manner should be treated in accordance with the Shared Asset Guideline.¹⁴⁴

In our view, this kind of transmission network support service is a distribution services because it is provided by means of, or in connection with, a distribution system.¹⁴⁵ We understand the service is provided by means of AusNet Service's substation capacitor banks that are controlled by the distribution control room.

We see that this service could be classified in one of three ways under the Rules.

¹⁴² AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, Appendices A and B, pp. 77–86.

¹⁴³ AEMO, *Victorian annual planning report - Electricity transmission network planning for Victoria*, July 2018, p. 28.

¹⁴⁴ AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April 2018, p. 8.

¹⁴⁵ See definition of a distribution service in NER, cl.10.

1. As a standard control service

AusNet Services' proposed transmission network support service could continue to be provided as it has in the past as a regulatory obligation. Under the National Electricity Law (NEL) a regulatory obligation on a regulated network service provider can be a distribution system safety duty or transmission system safety duty, or an obligation or requirement under the NEL or NER.¹⁴⁶ The NER requires that each network service provider must use reasonable endeavours to exercise its rights and obligations in relation to its networks so as to co-operate with and assist AEMO in the proper discharge of the AEMO power system security responsibilities.¹⁴⁷ Costs of providing the service are attributed to capex and opex building blocks and are cost recovered through DUoS, which is usual for a standard control service.

This approach, which appears to reflect practice to date, implies that the service forms part of the bundled common distribution service.

2. As an unregulated contestable service

Alternatively, transmission network support could be treated as a contestable service as proposed by AusNet Services. AusNet Services is not precluded from providing contestable distribution services. However, there are ring-fencing compliance requirements that may apply. In particular, ring-fencing obligations may restrict sharing of staff performing regulated and unregulated services, and use of the AusNet Services brand to provide unregulated services. Further, there are cost allocation requirements under our Ring-fencing Guideline. AusNet Services could apply for a waiver for some or all of these ring-fencing obligations, where it can demonstrate any harm to contestable markets does not exceed benefits to consumers.

3. As an alternative control service

It may also be feasible to offer this service as an alternative control service. This would enable the DNSP to earn revenue for providing the service, reflecting the fact that this service is being called upon by AEMO to greater extent than has previously been the case. An alternative control service classification may also be appropriate given that the service is attributable to a specific customer (AEMO), and there is limited potential competition for this kind of service, as it is tied to the operation of the shared distribution network.

Our main concern about AusNet Services' proposal to provide transmission support as an unregulated service relates to the use of the Shared Asset Guideline as a form of cost allocation. The Shared Asset Guideline enables distributors use their regulated distribution assets to earn unregulated revenue. For example by leasing out space on their distribution poles for a telecommunications company to install optical fibre network. Distribution customers benefit under a revenue sharing arrangement that is set out in the Guideline.

¹⁴⁶ NEL, cl. 2D(1).

¹⁴⁷ NER, cl. 4.3.4(a). Specifically, cl.4.3.1(v)(2), requires that AEMO investigate and review all major power system operational incidents and initiate action plans to manage abnormal situations or significant deficiencies, including power system voltages outside of those specific in the definition of satisfactory operating state.

However, application of the Shared Asset Guideline does not equate to adequate cost allocation pertaining to contestable services in a way that would satisfy the Ring-fencing Guideline.

More broadly, we understand that a number of distributors have started using distribution system assets to earn unregulated revenue directly in other markets using the Shared Asset Guideline. For example, in 2017 United Energy commenced offering demand response services into the Reliability and Emergency Reserve Trader (RERT) mechanism.¹⁴⁸ When the Shared Asset Guideline was developed in 2013, the AER envisioned that it would mostly apply to situations where the distributor was allowing third parties access to its distribution assets in order to sell unregulated services into other markets (such as the NBN Co. example above). AusNet Services' proposal and United Energy's RERT services reflect a different situation in which distributors both own the distribution assets and use those assets to sell unregulated services directly into other markets, rather than a third party. This likely reflects the increasing value of reliability and security services within the NEM as the energy mix shifts towards variable generation. In view of our concerns with this use of the Shared Asset Guideline, a review of this Guideline may be needed in this future.

For the purposes of this preliminary F&A, we have not classified AusNet Services' proposed transmission network support service. If adopted in our final Determination, this approach would make the service unclassified and unregulated, as requested by AusNet Services in their letter requesting to amend or replace the F&A. We seek stakeholder comments on this issue. Specifically we would be interested in stakeholder comments on the regulatory implications of this approach compared to DNSPs offering the service as a standard control service, which is implied by the past practice of AEMO directing DNSPs to provide this service, or as an alternative control service, as outlined above.

¹⁴⁸ See <https://www.unitedenergy.com.au/united-energys-demand-respond-results-for-summer-2017-2018/>.

2 Forms of control

Our distribution determination must impose controls over the prices (and/or revenues) of direct control services.¹⁴⁹ This section sets out our preliminary positions, together with our reasons, on the forms of control to apply to the Victorian distributors' direct control services for the 2021–25 regulatory control period. This section also sets out our preliminary positions on the formulae to give effect to these control mechanisms.

As discussed in section 1, we classify direct control services as standard control services or alternative control services. Different control mechanisms may apply to each of these classifications, or to different services within the same classification. Appendix B provides our preliminary classification of the Victorian network business' distribution services.

The form of control mechanisms in a distributor's regulatory proposal must be as set out in the relevant F&A.¹⁵⁰ Additionally, the formulae that give effect to the control mechanisms in a distributor's regulatory proposal must be the same as the formulae set out in the relevant F&A. The formulae cannot be altered between the F&A and the making of the determination unless we consider that there has been a material change in circumstances that justifies departing from the formulae set out in that F&A.¹⁵¹ However, without affecting the content of a Determination that has already been made, an F&A paper may be amended or replaced in accordance with the rules and with consultation.¹⁵²

2.1 AER's preliminary position

Our preliminary position is to apply the following forms of control in the 2021–25 regulatory control period:

- Revenue cap — for services we classify as standard control services.
- Revenue cap — for types 5 and 6 (including smart meters) metering services we classify as alternative control services
- Caps on the prices of individual services — for services we classify as alternative control services.

2.2 AER's assessment approach

Our consideration of the control mechanisms for direct control services consists of three parts:

- the form of the control mechanisms¹⁵³
- the formulae to give effect to the control mechanisms

¹⁴⁹ NER, cl. 6.2.5(a).

¹⁵⁰ NER, cl. 6.12.3(c).

¹⁵¹ NER, cl. 6.12.3(c1).

¹⁵² NER, cl 6.8.1(a)(2), 6.8.1(c)(3).

¹⁵³ NER, cl. 6.2.5(b).

- the basis of the control mechanism.¹⁵⁴

The NER sets out the form of control mechanisms that may apply to both standard and alternative control services:¹⁵⁵

- a schedule of fixed prices

A schedule of fixed prices specifies a price for every service provided by a distributor. The specified prices are escalated annually by inflation, the X factor and applicable adjustment factors. A distributor complies with the constraint by submitting prices matching the schedule in the first year and then escalated prices in subsequent years.

- caps on the prices of individual services (price caps)¹⁵⁶

Caps on the prices of individual services are the same as a schedule of fixed prices except that a distributor may set prices below the specified prices.

- caps on the revenue to be derived from a particular combination of services (revenue cap)

A revenue cap sets total annual revenue (TAR) for each year of the regulatory control period. A distributor complies with the constraint by forecasting sales for the next regulatory year and setting prices so the expected revenue is equal to or less than the TAR. At the end of each regulatory year, the distributor reports its actual revenues to us. We account for differences between the actual revenue recovered and the TAR in future years. This operation occurs through an unders and overs account, whereby any revenue under recovery (over recovery) is added to (deducted from) the TAR in future years.

- tariff basket price control (weighted average price cap or WAPC)

A WAPC is a cap on the average increase in prices from one year to the next. This allows prices for different services to adjust each year by different amounts. For example, some prices may rise while others fall, subject to the overall WAPC constraint. A weighted average is used to reflect that services may be sold in different quantities. Therefore, a small increase in the price of a frequently provided service must be offset by a large decrease in the price of an infrequently provided service. A distributor complies with the constraint by setting prices so the change in the weighted average price is equal to or less than the CPI-X cap. Importantly, the WAPC places no ceiling on the revenue recovered by a distributor in any given year. That is, if revenue recovered under the WAPC is greater than (less than) the expected revenue, the distributor keeps (loses) that additional (shortfall) revenue.

- revenue yield control (average revenue cap)

An average revenue cap is a cap on the average revenue per unit of electricity sold that a distributor can recover. The cap is calculated by dividing the TAR by a particular unit (or

¹⁵⁴ NER, cl. 6.2.6(a).

¹⁵⁵ NER, cl. 6.2.5(b).

¹⁵⁶ A price cap and a schedule of fixed prices are largely the same mechanism, with the only difference being that a price cap allows the distributors to charge below the capped price on some or all of the services.

units) of output, usually kilowatt hours (kWh). The distributor complies with the constraint by setting prices so the average revenue is equal to or less than the TAR per unit of output.

- a combination of any of the above (hybrid).

A hybrid control mechanism is any combination of the above mechanisms. Typically, hybrid approaches involve a proportion of revenue that is fixed and a proportion that varies according to pre-determined parameters, such as peak demand.

In considering our preliminary positions on the control mechanisms for the Victorian distributors' standard control services, we have only considered the continuation of the revenue cap, or the adoption of price caps or an average revenue cap. We have not considered the other forms of control mechanisms for standard control services. We remain of the view we have expressed previously - namely, that that they are not superior to either an average revenue cap or a revenue cap in addressing the factors set out in clause 6.2.5(c) of the NER.¹⁵⁷

We have not considered a schedule of fixed prices. We consider direct price control mechanisms do not provide the level of flexibility within the regulatory control period to manage distribution use of service charges shared across the broad customer base.

We have not considered a WAPC as our previous considerations on this type of control mechanism noted the incentives for distributors to systematically recover revenue above efficient cost recovery resulting in higher bills for consumers.¹⁵⁸ We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.¹⁵⁹

We have also not considered a hybrid approach as our previous deliberations considered the higher administrative costs outweigh the potential benefits of this form of control.¹⁶⁰

However, we are open to consideration on these other control mechanisms for making our final F&A where stakeholders consider an alternative control mechanism for the Victorian distributors' standard control services would best address the factors set out in clause 6.2.5(c) of the NER.

In considering our preliminary positions on the control mechanisms for the Victorian distributors' alternative control services, our consideration is based on whether there is reason to depart from the current price caps in terms of the factors set out in clause 6.2.5(c) of the NER. We have concluded that no such reason exists.

¹⁵⁷ AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 52

¹⁵⁸ For example, see: AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 82 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 78.

¹⁵⁹ NEL, s. 7.

¹⁶⁰ For example, see: AER, *Final framework and approach for Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 86.

2.2.1 Standard control services

In determining a control mechanism to apply to standard control services, we must have regard to the factors in clause 6.2.5(c) of the NER:

- need for efficient tariff structures
- possible effects of the control mechanism on administrative costs of us, the distributor, users or potential users
- regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination
- desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.

We also propose to have regard to three other factors which we consider are relevant to assessing the most suitable control mechanism:

- revenue recovery
- price flexibility and stability
- incentives for demand side management.

The basis of the control mechanism for standard control services must be of the prospective CPI-X form or some incentive-based variant.¹⁶¹

Section 2.3 sets out our consideration of each of the above factors in determining our preliminary positions of the form of control mechanisms for standard control services.

2.2.2 Alternative control services

In determining a control mechanism to apply to alternative control services, we must have regard to the factors in clause 6.2.5(d) of the NER:

- the potential for competition to develop in the relevant market and how the control mechanism might influence that potential
- the possible effects of the control mechanism on administrative costs for us, the distributor and users or potential users
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.

¹⁶¹ NER, cl. 6.2.6(a).

We consider that another relevant factor is the provision of cost reflective prices. Efficient prices (cost reflectivity) allow consumers to compare the cost of providing the service to their needs and wants. It also better promotes the national electricity objective by ensuring that customers only pay for services they use. Cost reflective prices also enable distributors to make efficient investment and demand side management decisions.

We must state what the basis of the control mechanism is in our distribution determination.¹⁶² This may utilise elements of Part C of chapter 6 of the NER with or without modification. For example, the control mechanism may use a building block approach or incorporate a pass through mechanism.¹⁶³

Section 2.4 sets out our consideration of each of the above factors in determining our preliminary positions on the form of control mechanism for alternative control services.

2.3 Reasons for AER's preliminary approach — control mechanism and formulae for standard control services

Our decision is to maintain a revenue cap for the Victorian distributors' standard control services for the 2021–25 regulatory control period. We consider the application of a revenue cap control mechanism best meets the factors set out under clause 6.2.5(c) of the NER.

A revenue cap will result in no additional administrative costs and allow for consistency of regulatory arrangements for standard control services both across regulatory periods and across jurisdictions.

A revenue cap will also result in benefits to consumers through a higher likelihood of revenue recovery at efficient costs and will provide better incentives for demand side management. Furthermore, our recent approach to the operation of the revenue cap has reduced the magnitude of overall price variability during a regulatory control period, which has been a concern in the past. We provide our consideration of these issues below.

2.3.1 Efficient tariff structures

In deciding on a control mechanism, the NER requires us to have regard to the need for efficient tariff structures.¹⁶⁴ We consider tariff structures are efficient if they reflect the underlying cost of supplying distribution services.

It is likely that efficient tariff structures can be developed and implemented under all types of control mechanisms. Our recent assessment of distributors' tariff structures has demonstrated that efficient tariff structures have been developed and will be implemented under both average revenue cap and revenue cap control mechanisms.

¹⁶² NER, cl. 6.2.6(b).

¹⁶³ NER, cl. 6.2.6(c).

¹⁶⁴ NER, cl. 6.2.5(c)(1).

Our previous considerations on the interaction between a control mechanism and its ability to deliver efficient tariff structures during a regulatory control period relied solely on the incentive properties of the different types of control mechanisms.¹⁶⁵ However, recent changes to the NER now require us to undertake a supplementary assessment of the efficiency of a distributor's tariff structures which are set out in a tariff structure statement. Therefore, consideration of the interaction between control mechanisms and efficient tariff structures should also be informed by our assessment of a distributor's tariff structure statement.

The requirement for distributors to prepare tariff structure statements is new. It arises from a significant process of reform to the NER governing distribution network pricing. The purpose of the reforms is to empower customers to make informed choices by:

- Providing better price signals—tariffs that reflect what it costs to use electricity at different times so that customers can make informed decisions to better manage their bills.
- Transitioning to greater cost reflectivity—requiring distributors to explicitly consider the impacts of tariff changes on customers, and engaging with customers, customer representatives and retailers in developing network tariff proposals over time.
- Managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for a set period of time.

A distributor's tariff structure statement sets out the tariff structures it can apply over a regulatory control period.¹⁶⁶ The tariff structure statement should show how a distributor applied the distribution pricing principles¹⁶⁷ to develop its tariff structures and the indicative price levels of tariffs for the coming five year regulatory control period. The network pricing objective of the distribution pricing principles is the focus for a distributor when developing its network tariffs. The objective is that:¹⁶⁸

the tariffs that a distributor charges for provision of direct control services to a retail customer should reflect the distributor's efficient costs of providing those services to the retail customer.

We must approve a tariff structure statement unless we are reasonably satisfied it will not comply with the distribution pricing principles or other relevant requirements of the NER.¹⁶⁹

In February 2017, we made final decisions on the initial tariff structure statements for SA Power Networks, Evoenergy (formerly ActewAGL) and the distributors in Queensland and

¹⁶⁵ For example, see: AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, pp. 79–81 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, pp. 76–77.

¹⁶⁶ NER, cl. 6.18.1A(a)(3).

¹⁶⁷ This is a reference to the NER' *pricing principles for direct control services*, alternatively described in this paper as the "distribution pricing principles"; NER, cl. 6.18.5(e)–(j).

¹⁶⁸ NER, cl. 6.18.5(a).

¹⁶⁹ NER, cl. 6.12.3(k).

New South Wales. On 28 April 2017, we made our final decision on TasNetworks' initial tariff structure statement.

Through the initial tariff structure statements many distributors will be introducing more cost reflective tariff structures, such as demand based tariffs. In our assessment we found no evidence to suggest that Evoenergy's average revenue cap or other distributors' revenue caps inhibited the ability to develop or implement efficient tariff structures. Therefore, we consider that efficient tariff structures can occur under both average revenue cap and revenue cap control mechanisms. On this basis, we also consider efficient tariff structures are likely to occur under all forms of control mechanisms, including price caps.

While our consideration of efficient tariff structures does not necessarily indicate a revenue cap should be favoured over an average revenue cap or price caps, our decision needs to be weighed against the other factors under clause 6.2.5(c) of the NER.

We note that tariff reform brought about by the tariff structure statements is still in its infancy. We may revisit the interaction between a control mechanism and efficient tariff structures for future F&As.

2.3.2 Administrative costs

In deciding on a control mechanism, the NER requires us to have regard to the possible effects of the control mechanism on administrative costs.¹⁷⁰ We consider, where possible, a control mechanism should minimise the complexity and administrative burden for us, the distributor, users, or potential users.

Generally, we consider there is little difference in administrative costs between control mechanisms under the building block framework in the long run. However, we consider the continuation of a revenue cap control mechanism to the Victorian distributors' standard control services would have the least complexity and administrative burden. The continuation of a revenue cap would impose no additional administrative costs for us, the Victorian distributors, users, or potential users.

In contrast, additional administrative costs will be incurred by at least the Victorian distributors and us in transitioning from a revenue cap to a price cap or alternative form of control mechanism. For example, new tariff models would need to be developed for annual pricing proposals to demonstrate compliance with the new control mechanism. Therefore, we consider the continuation of a revenue cap is superior in meeting the requirements in clause 6.2.5(c)(2) of the NER.

2.3.3 Existing regulatory arrangements

In deciding on a control mechanism, the NER requires us to have regard to the regulatory arrangements applicable to the relevant service immediately before the commencement of

¹⁷⁰ NER, cl. 6.2.5(c)(2).

the distribution determination.¹⁷¹ We note maintaining a revenue cap control mechanism for the Victorian distributors' standard control services provides for consistent regulatory arrangements for these services across regulatory control periods. Therefore, we consider the continuation of a revenue cap control mechanism is superior in meeting clause 6.2.5(c)(3) of the NER than an alternative control mechanism.

2.3.4 Desirability of consistency between regulatory arrangements

In deciding on a control mechanism, the NER requires us to have regard to the desirability of consistency between regulatory arrangements for similar services both within and beyond the relevant jurisdiction.¹⁷² We consider the continuation of a revenue cap control mechanism for the Victorian distributors' standard control services delivers consistent regulatory arrangements for these services across jurisdictions.

Apart from Evoenergy, all other electricity distributors' who are currently subject to economic regulation under the NER have a revenue cap control mechanism applied to their standard control services. We have decided to apply a revenue cap to Evoenergy's standard control services for the 2019–24 regulatory control period.¹⁷³ This means that from 1 July 2019 all distributors' standard control services will be subject to a revenue cap control mechanism. Therefore maintaining the Victorian distributors' revenue cap control mechanism will ensure consistent regulatory arrangements for these services across jurisdictions. For these reasons, we consider the continuation of a revenue cap control mechanism is superior in meeting clause 6.2.5(c)(4) of the NER than an alternative mechanism.

2.3.5 Revenue recovery

We consider that a control mechanism should give a distributor an opportunity to recover efficient costs. Also, a control mechanism should limit revenue recovery above such costs. Revenue recovery above efficient costs results in higher prices for end users. Further, allocative efficiency is reduced when a distributor recovers additional revenue from price sensitive services through prices above marginal cost.¹⁷⁴

Generally, we consider that a revenue cap provides a high likelihood of efficient cost recovery. Under a revenue cap, revenue recovery is fixed and unrelated to energy sales. Similarly, costs for distributors are largely fixed and unrelated to energy sales. Therefore, our view is that a revenue cap is likely to lead to efficient cost recovery.

¹⁷¹ NER, cl. 6.2.5(c)(3).

¹⁷² NER, cl. 6.2.5(c)(4).

¹⁷³ ActewAGL Distribution, *Response to AER preliminary framework and approach*, April 2017, p. 11.

¹⁷⁴ Allocative efficiency is achieved when the value consumers place on a good or service (reflected in the price they are willing to pay) equals the cost of the resources used up in production. The condition required is that price equals marginal cost. When this condition is satisfied, total economic welfare is maximised.

We also consider that a revenue cap incentivises distributors to reduce their expenditures because their revenues are assured during the regulatory control period. These lower costs can be shared with customers in future regulatory control periods.

In contrast, control mechanisms where revenue depends on energy sales (such as average revenue caps or price caps) provides distributors with incentives to understate sales forecasts and adjust tariffs to gain revenues above efficient cost levels.¹⁷⁵ A systematic recovery of revenue above efficient cost recovery results in higher bills for consumers.¹⁷⁶ We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.¹⁷⁷

In terms of efficient revenue recovery, we consider a revenue cap control mechanism better reflects the national electricity objective than those that rely on energy sales.¹⁷⁸

2.3.6 Pricing flexibility and stability

Price flexibility enables a distributor to restructure its tariffs to meet changes in the environment of operating an electricity distribution network during a regulatory control period. Price stability is important because it affects retailers' ability to manage risks incurred from changes to network tariffs, which they then package into retail plans for customers. It also affects customers' ability to manage their bills.

We consider that price flexibility is primarily influenced by the distribution pricing principles and the side constraint.¹⁷⁹ Therefore, price flexibility is similar for all control mechanisms as they are subject to the same distribution pricing principles and the same side constraint.

In terms of price stability, some control mechanisms are more likely to deliver stable prices than others. However, price instability can occur under all control mechanisms because the NER require various annual price adjustments regardless of the control mechanism.¹⁸⁰

Within a regulatory control period, an average revenue cap or price caps will deliver more overall price stability than a revenue cap. The increased variability under a revenue cap occurs because future revenues and tariffs are adjusted to account for the difference between the actual revenue recovered and the TAR. These differences are due to the variations between forecast and actual sales volumes. The true up of this under or over recovery of revenue is calculated in the unders and overs account.

¹⁷⁵ For example, see: AER, *Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 64–67; AER,

¹⁷⁶ For example, see: AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 82 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 78.

¹⁷⁷ NEL, s. 7.

¹⁷⁸ NEL, s. 7.

¹⁷⁹ The side constraint is a mechanism imposed on a distributor which limits the change in the expected average revenue for a tariff class, weighted by tariff component, from one regulatory year to the next.

¹⁸⁰ These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from transmission network service providers.

Typically there is a two year lag from when the under or over recovery of revenue occurs (year $t-2$) and the year in which audited accounts can be relied upon to make an accurate revenue true up adjustment (year t). This lagged effect may cause price instability when an under (over) recovery of revenue in one year is followed by an over (under) recovery in the following year. In this scenario, price movements go in one direction for first year and then go in the opposite direction the following year.

We have somewhat addressed this issue in our recent determinations by applying a rolling unders and overs account which includes an additional true up for the estimated under and over recovery of revenues for the year in between (year $t-1$).¹⁸¹ The inclusion of this estimated year helps smooth year-on-year revenue and tariff adjustments because the effects of the estimated year $t-1$ under or over recovery will have been largely accounted for when year $t-1$ becomes year $t-2$. That is, when year $t-1$ becomes year $t-2$ the adjustment to the TAR will only need to account for the difference between the estimated and actual under or over recovery and not the overall total under or over recovery.

In terms of stability across regulatory control periods, we consider an average revenue cap can result in greater price volatility compared to a revenue cap.¹⁸² This issue is particularly pronounced if a trend of falling demand and consumption has set in throughout the regulatory control period. This scenario would prompt a large upward adjustment in the X-factors (and hence prices) for the next regulatory control period under an average revenue cap. In contrast, the volume forecasts are updated annually under a revenue cap. This would mean that prices would rise gradually over the regulatory period (rather than jump up at the end of the period) if a trend of falling demand was evident.

On balance, when weighing price flexibility and stability along with the other factors we have considered, our preliminary position is to maintain the Victorian distributors' revenue cap control mechanism for standard control services. While we acknowledge a revenue cap has a higher likelihood of overall price instability during a regulatory control period, we consider our application of the rolling unders and overs account reduces the magnitude of this effect.

2.3.7 Deliberately under recovered revenue in the unders and overs account

We accept that there are times when distributors may make a business decision to recover below their allowed level of revenue such as by choosing to price services at lower levels than would be allowable under the revenue cap.¹⁸³ In these cases, the distributor decides to accept the under-recovery for reasons of its own commercial interest.

¹⁸¹ For example, see: AER, *Final Decision, CitiPower distribution determination 2016 to 2020: Attachment 14—Control mechanisms*, May 2016, Appendix A, pp. 18–19.

¹⁸² AER, *Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 67–69.

¹⁸³ See for example TasNetworks' demand based time of use tariff incentive as discussed in TasNetworks' response to AER Information Request 009, 29 March 2018, p. 5

In particular, while it is possible that the under recovery may result in a financial loss, it is also possible for an under recovery to involve a strategic financial choice that reduces costs to a degree that exceeds the reduced revenue.¹⁸⁴

This is in contrast to under recovery that arises due to a natural variation between forecast quantities of a services offered and actual quantities achieved. This type of under-recovery is disadvantageous to the distributor.

If a distributor chooses, in its own interests, to under-recover revenue, it is no worse off than had it not made that under recovery. In these circumstances, therefore, we do not consider that it is in the interest of consumers that the revenue that is not recovered be able to be recovered later, as this would be inefficient and would give the distributor an unintended additional benefit.

Accordingly, as part of our proposed revenue cap, we will not count this revenue as an under recovery for the purpose of the under and overs account and, by extension, will therefore not subsequently increase the total allowable revenue in future years.

Instead, we will require that any deliberately under recovered revenue in a year t will be added to the annual revenue in year t prior to calculating any under or over recovery in year t.

The below example does not constitute the entirety of an unders and overs account which will need to be maintained. It merely demonstrates the principle of how the deliberately under-recovered revenue should be captured.

Table 2.4 Example calculation of DUoS unders and overs recovery including deliberately under recovered revenue

	Year t
Revenue from DUoS charges	\$1,000,000
Revenue deliberately under-recovered in year	\$100,000
(A) Revenue from DUoS charges including deliberately under-recovered revenue	\$1,100,000
(B) Total allowable revenue	\$1,200,000

¹⁸⁴ For example, by accepting lower rates for tariffs that peak at critical times, more customers choose those tariffs. These tariffs discourage demand at peak times and reduce strain on the network lowering costs.

2.3.8 Incentives for demand side management

Demand side management refers to the implementation of non-network solutions to avoid the need to build network infrastructure to meet increases in annual or peak demand.¹⁸⁵ Where prices are cost reflective, consumers and providers of demand side management face efficient incentives because they can take into account the cost of providing the service in decision making.

Under a revenue cap a distributor's revenue is fixed over the regulatory control period. A distributor can therefore improve its financial position by reducing costs. This creates an incentive for a distributor to undertake demand side management projects that reduce total costs, even if that means the distributor does not build new assets or replace existing ones.¹⁸⁶ We consider this provides a stronger incentive for a distributor to undertake demand side management within a regulatory control period compared to a control mechanism that has expected revenues varying with overall sales, such as in a price cap.

Under an average revenue cap or price cap control mechanism, a distributor's revenues are linked more closely to actual volumes of electricity distributed. As a result, distributors' profits increase with sales if the marginal revenue is greater than the marginal cost of providing services. Demand side management may not be attractive for distributors if such projects result in less revenue as a result of the decline in demand or consumption that they induce.

2.3.9 Formulae for control mechanism

We are required to set out our proposed approach to the formulae that give effect to the control mechanisms for standard control services in the F&A paper.¹⁸⁷ In making a distribution determination, the formulae must be as set out in our final F&A, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A paper.¹⁸⁸ Below is the proposed formula to apply to the Victorian distributors' standard control services revenues. We consider that the formula gives effect to the revenue cap.

Figure 2.1 Preliminary positions revenue cap to be applied to the Victorian distributors' standard control services

¹⁸⁵ Generally peak demand is referred to as the maximum load on a section of the network over a very short time period.

¹⁸⁶ That is, demand side management projects that result in a reduction in future network expenditure greater than the cost of implementing the demand side management projects.

¹⁸⁷ NER, cl. 6.8.1(b)(2)(ii).

¹⁸⁸ NER, cl. 6.12.3(c1).

1. $TAR_t \geq \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} q_t^{ij}$ $i = 1, \dots, n$ and $j = 1, \dots, m$ and $t = 1, 2, \dots, 5$
2. $TAR_t = AAR_t + I_t + B_t + C_t$ $t = 1, 2, \dots, 5$
3. $AAR_t = AR_t \times (1 + S_t)$ $t = 1$
4. $AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t) \times (1 + S_t)$ $t = 2, \dots, 5$

Where:

TAR_t is the total allowable revenue in year t.

p_t^{ij} is the price of component 'j' of tariff 'i' in year t.

q_t^{ij} is the forecast quantity of component 'j' of tariff 'i' in year t.

t is the regulatory year.

AR_t is the annual smoothed revenue requirement in the Post Tax Revenue Model (PTRM) for year t.

AAR_t is the adjusted annual smoothed revenue requirement for year t.

I_t is the sum of incentive scheme adjustments in year t. To be decided in the distribution determination.

B_t is the sum of annual adjustment factors in year t. Likely to incorporate but not limited to adjustments for the unders and overs account. To be decided in the distribution determination.

C_t is the sum of approved cost pass through amounts (positive or negative) with respect to regulatory year t, as determined by the AER. It will also include any end-of-period adjustments in year t. To be decided in the distribution determination.

S_t is the s-factor for regulatory year t.¹⁸⁹ As it currently stands, the s-factor will incorporate any adjustments required due to the application of the AER's STPIS.¹⁹⁰

¹⁸⁹ The meaning for year "t" under the price control formula is different to that in Appendix C of STPIS. Year "t+1" in Appendix C of STPIS is equivalent to year "t" in the price control formula of this decision.

¹⁹⁰ AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

However, we are currently undertaking a review of the STPIS. How the s-factor will apply within the revenue cap formula may depart from the current arrangements. Depending on the outcome of our review, provision to adjust revenues for performance against the STPIS may be made through either the S or I factors as set out in this preliminary F&A paper. If the review is completed in time, the distributors may need to apply the revised STPIS for the 2021–25 regulatory control period. We will consider the application of the revised STPIS during the revenue determination process.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities¹⁹¹ from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1

divided by

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2

minus one.

For example, for 2020–21, year t–2 is the December quarter 2018 and year t–1 is the December quarter 2019.

X_t is the X-factor in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the distribution determination.

2.4 AER's reasons — control mechanism for alternative control services

Our preliminary position is to apply caps on the prices of individual services (price caps) in the 2021–25 regulatory control period to all of the Victorian distributors' alternative control services with the exception of metering services. We propose classifying the following services as alternative control services:

- public lighting services
- network ancillary services
- metering services.

In the current regulatory period, we have applied a revenue cap to the type 5 and 6 and smart metering service, which is currently classified as an alternative control service, as this service is not subject to competition. We propose to continue this approach. .

¹⁹¹ If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

We note the Victorian distributors' remaining alternative control services are currently subject to price cap regulation. The continuation of these price caps over the 2021–25 regulatory control period best meets the factors set out under clause 6.2.5(d) of the NER.

Unlike standard control services, the NER is not prescriptive on the basis of the control mechanism for alternative control services.¹⁹² For example, the price caps could be based on a building block approach, or a modified building block cost build up. We have set out our proposed formulae that will give effect to the price cap control mechanisms in Figure 2.2 and Figure 2.3 below. However, it is at the distributor's discretion as to the approach it undertakes to develop its initial prices.

Prices for certain ancillary services will be determined on a quoted basis. Prices for quoted services are based on quantities of labour and materials with the quantities dependent on a particular task. For example, where a customer seeks a non-standard connection which may involve an extension to the network the distributor may only be able to quote on the service once it knows the scope of the work. Because of this uncertainty, our preliminary positions price cap formula for quoted services differs to that proposed to apply to metering and fee based services. Our quoted services price cap is consistent with the approach we have adopted in the past.

A further consideration relates to the treatment of new services that might be offered by the Victorian distributors within the regulatory control period. Where such services were not identified at the time of the AER Determination but for which the service clearly falls within one of the established service groupings, we propose that a quoted price approach be adopted based on a similar service within that same service grouping. For example, the price for a new type of security lighting would be set based on the same approach as a similar security lighting service. This approach would give the distributors additional flexibility to introduce new services while offering consumers the protections associated with price regulation. If there was no other similar service, the new service would be unregulated and may therefore be subject to ring-fencing restrictions that affect use of the Victorian distributor's brands as well as sharing of staff and offices in offering the new services.

Application for the introduction of a new alternative control service, within the regulatory control period, is to be made at the time of the annual price submission. The application should provide a detailed description of the service to be introduced along with a plan for how the new service will be charged.

Our preliminary consideration of the relevant factors is set out below.

2.4.1 Influence on the potential to develop competition

We consider a departure from the current price cap controls for the Victorian distributors' alternative control services would not have a significant impact on the potential development of competition. We consider the primary influence on competition development will be the

¹⁹² NER, cl. 6.2.6(c).

classification of services as alternative control services. Chapter 1 discusses service classification.

2.4.2 Administrative costs

Where possible, a control mechanism should minimise the complexity and administrative burden for us, the distributor, users, and potential users. The continuation of price caps will impose no additional administrative costs for us, the Victorian distributors or users.

Additional administrative costs will be incurred at least to the Victorian distributors and us if an alternative control mechanism was applied to these services.

2.4.3 Existing regulatory arrangements

We consider consistency across regulatory control periods is generally desirable. Our preliminary position maintains this regulatory consistency as it continues the application of price cap control mechanisms for the Victorian distributors' alternative control services.

2.4.4 Desirability of consistency between regulatory arrangements

We consider consistency across jurisdictions is also generally desirable. Our preliminary position maintains this consistency across jurisdictions.

We note that apart from the Victorian distributor's metering services which are currently subject to a revenue cap, price cap control mechanisms are currently applied to the alternative control services for all other electricity distributors subject to economic regulation under the NER.

2.4.5 Cost reflective prices

We consider that price caps are more suitable than other control mechanisms for delivering cost reflective prices. To apply price caps to the prices, we estimate the cost of providing each service and set the price at that cost. This will enhance cost reflectivity on both competitive and non-competitive services.

2.4.6 Formulae for alternative control services

We are required to set out our proposed approach to the formulae that gives effect to the control mechanisms for alternative control services.¹⁹³ In making a distribution determination, the formulae must be as set out in our final F&A, unless we consider that material change in circumstances justifies departing from the formulae as set out in the F&A.¹⁹⁴

¹⁹³ NER, cl. 6.8.1(b)(2)(ii).

¹⁹⁴ NER, cl. 6.12.3(c1).

Below are our preliminary price cap formulae which will apply to the Victorian distributors' alternative control services.

Figure 2.2 Preliminary price cap formula to be applied to the Victorian distributors' public lighting and ancillary services (fee based)

$$\bar{p}_t^i \geq p_t^i \quad i=1,\dots,n \text{ and } t=1, 2,\dots,5$$

$$\bar{p}_t^i = \bar{p}_{t-1}^i \times (1 + \Delta CPI_t) \times (1 - X_t^i) + A_t^i$$

Where:

\bar{p}_t^i is the cap on the price of service i in year t.

p_t^i is the price of service i in year t. The initial value is to be decided in the distribution determination.

\bar{p}_{t-1}^i is the cap on the price of service i in year t-1.

t is the regulatory year.

ΔCPI_t is the annual percentage change in the ABS consumer price index (CPI) All Groups, Weighted Average of Eight Capital Cities¹⁹⁵ from the December quarter in year t-2 to the December quarter in year t-1, calculated using the following method:

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t-1

divided by

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t-2

minus one.

For example, for 2020-21, year t-2 is the December quarter 2018 and year t-1 is the December quarter 2019.

X_t^i is the X factor for service i in year t. The X factors are to be decided in the distribution determination and will be based on the approach the distributor undertakes to develop its initial prices.

¹⁹⁵ If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

A_t^i is the sum of any adjustments for service i in year t . Likely to include, but not limited to adjustments for any approved cost pass through amounts (positive or negative) with respect to regulatory year t , as determined by the AER.

Figure 2.3 Preliminary price cap formula to be applied to the Victorian distributors' quoted services

$$\text{Price} = \text{Labour} + \text{Contractor Services} + \text{Materials}$$

Where:

Labour consists of all labour costs directly incurred in the provision of the service which may include labour on-costs, fleet on-costs and overheads. Labour is escalated annually by $(1 + \Delta CPI_t)(1 - X_t^i)$ where:

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities¹⁹⁶ from the December quarter in year $t-2$ to the December quarter in year $t-1$, calculated using the following method:

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year $t-1$

divided by

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year $t-2$

minus one.

For example, for 2020–21, year $t-2$ is the December quarter 2018 and year $t-1$ is the December quarter 2019.

X_t^i is the X factor for service i in year t . The X factor is to be decided in the distribution determination and will be based on the approach the distributor undertakes to develop its initial prices.

Contractor Services reflect all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.

Materials reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads.

¹⁹⁶ If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

Figure 2.4 Preliminary revenue cap formula to be applied to the Victorian distributors' type 5, 6 and smart metering - regulated service

$$(1) \quad TARM_t \geq \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} q_t^{ij} \quad i=1,\dots,n \text{ and } j=1,\dots,m \text{ and } t=1,\dots,5$$

$$(2) \quad TARM_t = AR_t + T_t + B_t \quad t = 1,2,\dots,5$$

$$(3) \quad AR_t = AR_{t-1}(1 + \Delta CPI_t)(1 - X_t) \quad t = 1,2,\dots,5$$

Where:

$TARM_t$ is the total annual revenue for annual metering charges in year t.

p_t^{ij} is the price of component i of tariff j in year t.

q_t^{ij} is the forecast quantity of component i of tariff j in year t.

AR_t is the annual revenue requirement for year t.

AR_{t-1} in 2021 is the annual smoothed revenue requirement in the Post Tax Revenue Model for the 2021 year in 2020 dollar value. After 2012 this is the AR_t from the previous year.

T_t is the adjustments in year t for true-ups relating to the AMI-OIC.

B_t is the sum of annual adjustment factors in year t for the overs and unders account.

ΔCPI_t is the percentage increase in the consumer price index. To be decided in the final decision.

X_t is the X-factor in real terms in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the final determination.

3 Incentive schemes

This chapter sets out our preliminary position on the application of a range of incentive schemes to the Victorian distributors for the 2021–25 regulatory control period. At a high level, our preliminary position is to apply the:

- service target performance incentive scheme
- efficiency benefit sharing scheme
- capital expenditure sharing scheme
- demand management incentive scheme and demand management innovation allowance mechanism
- Victoria F-factor scheme.

3.1 Service target performance incentive scheme

This section sets out our proposed approach and reasons for applying the service target performance incentive scheme (STPIS) to the Victorian distributors in the next regulatory control period.

Our distribution STPIS¹⁹⁷ provides a financial incentive to distributors to maintain and improve service performance. The scheme aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributor's incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).

The STPIS operates as part of the building block determination and contains two mechanisms:

- The service standards factor (s-factor) adjustment to the annual revenue allowance for standard control services rewards (or penalises) distributors for improved (or diminished) service compared to predetermined targets. Targets relate to service parameters pertaining to reliability and quality of supply, and customer service.
- A guaranteed service level (GSL) component composed of direct payments to customers¹⁹⁸ experiencing service below a predetermined level. This component only applies if there is not another GSL scheme already in place.¹⁹⁹

¹⁹⁷ AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009. Currently under review, however the amendment process is not yet complete.

¹⁹⁸ Except where a jurisdictional electricity GSL requirement applies.

¹⁹⁹ Service level is assessed (unless we determine otherwise) with respect to parameters pertaining to the frequency and duration of interruptions; and time taken for streetlight repair, new connections and publication of notices for planned interruptions.

While the mechanics of how the STPIS will operate are outlined in our scheme, we must set out key aspects specific to the Victorian distributors in the next regulatory control period at the determination stage, including:

- the maximum revenue at risk under the STPIS
- how the distributors' networks will be segmented for the purpose of setting performance targets
- the applicable parameters for the s-factor adjustment of annual revenue
- performance targets for the applicable parameters in each network segment
- the criteria for certain events to be excluded from the calculation of annual performance and performance targets
- incentive rates that determine the penalties and rewards under the scheme.

The Victorian distributors may propose to vary the application of the STPIS in their respective regulatory proposals.²⁰⁰ We can accept or reject the proposed variation in our determination. Each year we will calculate the Victorian distributors' s-factor based on service performance in the previous year against targets, subject to the revenue at risk limit. Our national STPIS includes a banking mechanism, allowing distributors to propose delaying a portion of the revenue increment or decrement for one year to limit price volatility for customers.²⁰¹ A distributor proposing a delay must provide in writing its reasons and justification as to why a delay will result in reduced price variations to customers.

Our STPIS currently applies to the Victorian distributors. The Victorian distributors are currently subject to a financial penalty or reward of ± 5 per cent. In the previous regulatory control period of 2016-20, we did not apply the GSL component as the Victorian distributors were subject to a Victorian jurisdictional GSL scheme under clause 6 of the ESCV Electricity Distribution Code.

3.1.1 AER's preliminary position

Our preliminary position is to continue to apply the national STPIS to the Victorian distributors in the 2021–25 regulatory control period. We propose to:

- set revenue at risk for each distributor within a range of ± 5 per cent
- segment the network according to the four STPIS feeder categories (CBD, urban, short rural and long rural as appropriate for each distributor) as per the scheme's definitions
- apply the system average interruption duration index or SAIDI, system average interruption frequency index or SAIFI, momentary interruption frequency index event or MAIFI and customer service (telephone answering) parameters

²⁰⁰ AER, *Electricity distribution network service providers – service target performance incentive scheme*, 1 November 2009, cl. 2.2.

²⁰¹ AER, *Electricity distribution network service providers – service target performance incentive scheme*, 1 November 2009, cl. 2.5(d) and (e).

- set performance targets based on the distributor's average performance over the past five regulatory years
- apply the method in the STPIS for excluding specific events from the calculation of annual performance and performance targets
- apply the method and value of customer reliability (VCR) values as indicated in AEMO's 2014 Value of Customer Reliability Review final report, unless a more up-to-date value is available.

We will not apply the GSL component of the STIPS, as the Victorian distributors remain subject to a jurisdictional GSL scheme.

We are currently undertaking a review of the STPIS. One of the significant changes is to change the threshold definition of momentary interruption from the current less than one minute to less than three minutes. If the review is completed in time and subject to the necessary historical data being available, the new scheme will be applied to Victorian distributors for the 2021–25 regulatory control period.

3.1.2 AER's assessment approach

In deciding how to apply the current STPIS we have considered the requirements of the NER. The NER sets out certain requirements in relation to developing and implementing a STPIS.²⁰² These include:

Jurisdictional obligations

- consulting with the authorities responsible for the administration of relevant jurisdictional electricity legislation
- ensuring that service standards and service targets (including GSL) set by the scheme do not put at risk the distributor's ability to comply with relevant service standards and service targets (including GSL) specified in jurisdictional electricity legislation and any regulatory obligations or requirements to which the distributor is subject.

Benefits to consumers

We must take into account the benefits to consumers of applying the STPIS. This includes:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any penalty or reward under the scheme
- the willingness of the customer or end user to pay for improved performance in the delivery of services
- balanced incentives
- the past performance of the distribution network

²⁰² NER, cl. 6.6.2(b).

- any other incentives available to the distributor under the NER or the relevant distribution determination
- the need to ensure that the incentives are sufficient to offset any financial incentives the distributor may have to reduce costs at the expense of service levels
- the possible effects of the schemes on incentives for the implementation of non-network alternatives.

We considered the benefits to consumers of applying the STPIS when we developed the scheme. These considerations are set out in our final decision for the distribution STPIS.²⁰³

3.1.3 Reasons for AER's preliminary position

Our reasons for applying the STPIS to the Victorian distributors in the next regulatory control period are set out below.

Jurisdictional obligations

In Victoria, the ESCV administers and monitors compliance with the distribution licence conditions set out in the Electricity Distribution Code. Our proposed approach does not intend to compromise the distributors' ability to comply with jurisdictional licence obligations or create duplication. We therefore propose to not apply the GSL component of our national STPIS while the GSL arrangements in Victoria remain in place.

Benefits to consumers

We are mindful of the potential impact of the STPIS on consumers. Under the NER, we must consider customers' willingness to pay for improved service performance so benefits to consumers are sufficient to warrant any penalty or reward under the STPIS.²⁰⁴

Under the STPIS, a distributor's financial penalty or reward in each year of the regulatory control period is the change in its annual revenue allowance after the s-factor adjustment. Economic analysis of the value consumers place on improved service performance is an important input to the administration of the scheme. VCR studies estimate how willing customers are to pay for improved service reliability as a monetary amount per unit of unserved energy during a supply interruption.

The VCR estimates currently in our national STPIS are taken from studies conducted for the Essential Services Commission Victoria and Essential Services Commission of South Australia.²⁰⁵

²⁰³ AER, *Final decision: Electricity distribution network service providers Service target performance incentive scheme*, 1 November 2009.

²⁰⁴ NER, cl. 6.6.2(b)(3)(vi).

²⁰⁵ Charles River Associates, *Assessment of the Value of Consumer Reliability (VCR) - Report prepared for VENCORP*, Melbourne 2002; KPMG, *Consumer Preferences for Electricity Service Standards*, 2003.

In September 2014, AEMO completed analysis of the VCR across the NEM.²⁰⁶ We stated in our final decision for the NSW distributors' 2015–19 regulatory period and our final F&A for NSW distributors' 2019–24 regulatory period,²⁰⁷ that we will apply the latest value for VCR through the distribution determination in calculating the incentive rates. We consider the 2014 AEMO VIC VCR better reflects the willingness of customers to pay for the reliable supply of electricity in Victoria, unless a more up-to-date VCR is available at the time of our Final Decision. We consider that this approach is still appropriate.

Incentive rates will be calculated at the commencement of the regulatory control period (in the distribution determination) and will apply for the duration of the regulatory control period.

In December 2017, the COAG Energy Council submitted a rule change request that would allocate responsibility for updating and reviewing VCRs on an on-going basis to the AER. The AEMC published a consultation paper in May 2018.²⁰⁸

In its request to replace the current F&A, AusNet services submitted that it is currently unclear whether the AER intends to produce updated VCRs that would apply to the 2021-25 regulatory control period. AusNet Services considers that we should specify in the F&A the VCR that will be applied in the 2021-25 control period as the VCR is a fundamental input into AusNet Services' planning processes and any change will have material impacts on the scope and timing of planned work. AusNet Services submitted that it is critical that the AER provides time for AusNet Services to factor any updated value into its regulatory proposal and allow time for consultation with stakeholders, including the Customer Forum, on the impact of the value adopted for the regulatory proposal.²⁰⁹

We propose that the latest available VCR will be used to set the incentive rates under STPIS for our final decision for Victorian distributors for the 2021-25 regulatory control period. This means that we will apply the VCR values from the AEMO's 2014 analysis to the STPIS for the Victorian distribution determinations. Should the AER develop a new VCR prior to the release of the final decision, we will incorporate the latest available VCR in our final determination. We believe that this approach is preferable, as it reflects the most recent VCR values.

Our proposed approach is to apply the scheme standard level of revenue at risk for the Victorian distributors at ± 5 per cent as we do not consider that a lower than scheme standard level would fully achieve the intended outcomes of the STPIS.

Balanced incentives

We administer our incentive schemes within a regulatory control period to align distributor incentives with the NEO. In implementing the STPIS, we need to be aware of both the

²⁰⁶ AEMO, *Value of customer reliability review - Final report*, September 2014.

²⁰⁷ AER, *Final framework and approach for Ausgrid, Endeavour and Essential Energy 2019-24*, July 2017, p. 61.

²⁰⁸ See <https://www.aemc.gov.au/news-centre/media-releases/have-your-say-new-aer-role-determine-values-customer-reliability>.

²⁰⁹ AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace framework and approach*, 30 April 2018, p. 6.

operational integrity of the scheme and how it interacts with our other incentive schemes. This is discussed below.

Defining performance targets

How we measure actual service performance and set performance targets can significantly impact how well the STPIS meets its stated objectives.

The NER requires us to consider past performance of the distributor's network in developing and implementing the STPIS.²¹⁰ Our preferred approach is to base performance targets on the distributors' average performance over the past five regulatory years.²¹¹ Using an average calculated over multiple years instead of applying performance targets based solely on the most recent regulatory year limits a distributor's incentive to underperform in a specific year to make future targets less onerous.

Under this approach, distributors will only receive a financial reward for achieving reliability improvements. More importantly, a distributor can only retain the reward if it can maintain the reliability improvements. This is because once an improvement is made, the benchmark performance targets will be adjusted to reflect the improved level of performance. If it allows reliability to decline in the future, the distributor will be penalised. Our STPIS limits variability in penalties and rewards caused by circumstances outside the distributor's control. We exclude interruptions to supply deemed to be outside the major event day boundary from both the calculation of performance targets and measured service performance.

Interactions with our other incentive schemes

In applying the STPIS, we must consider any other incentives available to the distributor under the NER or relevant distribution determination.²¹² In Victoria, the STPIS will interact with our expenditure and demand management incentive schemes.

The efficiency benefit sharing scheme (EBSS) provides a distributor with an incentive to reduce operating costs. The STPIS counterbalances this incentive by discouraging cost reductions that lead to a decline in performance. The s-factor adjustment of annual revenue depends on the distributor's actual service performance compared to predetermined targets.

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.²¹³

The capital expenditure sharing scheme (CESS) rewards a distributor if actual capex is lower than the approved forecast amount for the regulatory year. Since our performance targets will reflect planned reliability improvements, any incentive a distributor may have to reduce capex by not achieving the planned performance outcome will be curtailed by the STPIS penalty.

²¹⁰ NER, cl. 6.6.2(b)(3)(iii).

²¹¹ Subject to any modifications required under cl. 3.2.1(a) and (b) of the national STPIS.

²¹² NER, cl. 6.6.2(b)(3)(iv).

²¹³ Included in the distributor's approved forecast capex for the next period.

3.2 Efficiency benefit sharing scheme

The EBSS is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and consumers. Consumers benefit from improved efficiencies through lower network prices in future regulatory control periods.

We address our position on the application of the EBSS in relationship to our proposed opex forecasting approach and benchmarking below. We also explain the rationale underpinning the scheme.

This section sets out our preliminary position and reasons on how we intend to apply the EBSS to the Victorian distributors in the 2021–25 regulatory control period.

3.2.1 AER's preliminary position

We intend to apply the EBSS to the Victorian distributors in the 2021–25 regulatory control period if we are satisfied the scheme will fairly share efficiency gains and losses between the distributors and consumers.²¹⁴ This will occur only if the opex forecast for the following period is based on the distributors' revealed costs. Our distribution determinations for the Victorian distributors for the 2021–25 regulatory control period will specify if and how we will apply the EBSS.²¹⁵

3.2.2 AER's assessment approach

The EBSS must provide for a fair sharing of opex efficiency gains and efficiency losses between a network service provider and network users.²¹⁶ We must also have regard to the following factors in developing and implementing the EBSS:²¹⁷

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
- the need to provide service providers with a continuous incentive to reduce opex
- the desirability of both rewarding service providers for efficiency gains and penalising service providers for efficiency losses
- any incentives that service providers may have to capitalise expenditure
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

3.2.3 Reasons for AER's preliminary position

²¹⁴ NER, cl. 6.5.8(a).

²¹⁵ AER, *Efficiency benefit sharing scheme*, 29 November 2013.

²¹⁶ NER, cl. 6.5.8(a).

²¹⁷ NER, cl. 6.5.8(c).

The EBSS currently applies to the Victorian distributors in the 2016–20 regulatory control period.

We will decide if and how we will apply the EBSS to the Victorian distributors in the 2021–25 regulatory control period in our determinations. The decision to apply the EBSS will depend on whether we expect to use the distributors' revealed costs in the 2021–25 regulatory control period to forecast opex in the following period.

Why we would apply the EBSS

We will only apply the EBSS in the 2021–25 regulatory control period if we expect we will use a revealed cost forecasting approach to forecast opex for the 2026–30 regulatory control period.

The EBSS is intrinsically linked to our revealed cost forecasting approach. This approach relies on identifying an efficient opex amount in the base year (the 'revealed costs' of the distributor), which we use to develop a total opex forecast. When a business makes an incremental efficiency gain, it receives a reward through the EBSS, and consumers benefit through a lower revealed cost forecast for the subsequent period. This is how efficiency improvements are shared between consumers and the business.

Under a revealed cost approach without an EBSS, a distributor has an incentive to spend more opex in the expected base year. Also, a distributor has less incentive to reduce opex towards the end of the regulatory control period, where the benefit of any efficiency gain is retained for less time.

If we use a revealed cost forecasting approach we apply the EBSS because:

- it reduces the incentive for a distributor to inflate opex in the expected base year in order to gain a higher opex forecast for the next regulatory control period
- it provides a continuous incentive for a distributor to pursue efficiency improvements across the regulatory control period. This is because the EBSS allows a distributor to retain efficiency gains for a total of six years, regardless of the year in which it was made.

In implementing the EBSS we also consider any incentives distributors may have to capitalise expenditure.²¹⁸ Where opex incentives are balanced with capex incentives, a distributor does not have an incentive to favour opex over capex, or vice-versa. If the CESS and EBSS are both applied, these incentives will be relatively balanced. We discuss the CESS further in section 3.3.

We also consider the effects of implementing the EBSS on incentives for non-network alternatives²¹⁹ (which are generally opex rather than capex). When the CESS and EBSS both apply, a distributor has an incentive to implement a non-network alternative if the increase in opex is less than the corresponding decrease in capex. In this way the distributor

²¹⁸ NER, cl. 6.5.8(c)(4).

²¹⁹ NER, cl. 6.5.8(c)(5).

will receive a net reward for implementing the non-network alternative.²²⁰ Non-network alternatives and the demand management incentives, including the new DMIS, are discussed further in section 3.4.

We are currently reviewing the interaction of operating expenditure forecasts, the EBSS and the new DMIS. We will seek to confirm our position as part of the regulatory determination process, but note that in implementing the EBSS and DMIS we will seek to provide balanced opex and capex incentives that encourage a distributor to identify and undertake efficient demand management options.

Why we would not apply the EBSS

We will not apply the EBSS if it is likely we will *not* use a revealed cost forecasting approach to forecast opex for the 2026–30 regulatory control period.

If we apply the EBSS but do not forecast opex using revealed costs, a distributor could in theory receive an EBSS reward for efficiency gains (at a cost to consumers), but consumers would not benefit through a lower revealed cost forecast. If the distributor expects this, it has an incentive to increase its EBSS carryover by underspending in its base year, knowing the underspend will not reduce its opex forecast.²²¹ Consumers would pay the EBSS reward but not receive a share of the underspend and would be worse off. This outcome is contrary to the NER which requires that the EBSS must provide for a fair sharing of efficiency gains and losses between a distributor and consumers.²²²

If a distributor's revealed costs in the 2016–20 regulatory control period are materially higher than the opex incurred by a benchmark efficient distributor, we will be unlikely to use revealed costs to forecast opex for the 2021–25 regulatory control period. In which case, we will be unlikely to apply the EBSS.

3.3 Capital expenditure sharing scheme

The CESS provides incentives for distributors to undertake efficient capex throughout the regulatory control period by rewarding efficiency gains and penalising efficiency losses. Consumers benefit from improved efficiency through lower network prices in the future. This section sets out our proposed approach and reasons for our intention to apply version 1 (dated 29 November 2013) of the CESS to the distributors.

The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between a distributor and network users.

220 When the distributor spends more on opex it incurs approximately 30 per cent of that increase as a result of the EBSS. At the same time it retains 30 per cent of the capex decrease through the CESS. So where the decrease in capex is larger than the increase in opex the distributor receives a larger reward than penalty, a net reward.

221 In our explanatory statement to the EBSS, we discuss why we should exclude the expenditure categories not forecast using a single year revealed cost forecasting method from the EBSS to prevent network users being worse off. AER, *Explanatory statement - efficiency benefit sharing scheme*, November 2013, pp. 18-19.

222 NER, cl'6.5.8(a).

The CESS works as follows:

- We calculate the cumulative underspend or overspend amount for the current regulatory control period in net present value terms.
- We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend amount to work out what the distributor's share of any underspend or overspend should be.
- We calculate the CESS payments taking into account the financing benefit or cost to the distributor of any underspend or overspend amounts.²²³ We can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.
- The CESS payments will be added to or subtracted from the distributor's regulated revenue as a separate building block in the next regulatory control period.

Under the CESS a distributor retains 30 per cent of the financing benefit or cost of any underspend or overspend amount, while consumers retain 70 per cent of the financing benefit or cost of any underspend or overspend amount.

3.3.1 AER's preliminary position

Our preliminary position is to apply the CESS, as set out in our capex incentives guideline,²²⁴ to the Victorian distributors in each regulatory year of the 2021–25 regulatory control period.

3.3.2 AER's assessment approach

In deciding whether to apply a CESS to a distributor, and the nature and details of any CESS to apply to a distributor, we must:²²⁵

- make that decision in a manner that contributes to the capex incentive objective set out in the NER²²⁶
- consider the CESS principles,²²⁷ capex objectives,²²⁸ other incentive schemes, and where relevant the opex objectives, as they apply to the particular distributor, and the circumstances of the distributor.

Broadly speaking, the capex incentive objective is to ensure that only capex that meets the capex criteria enters the RAB used to set prices. Therefore, consumers only fund capex that is efficient and prudent.

²²³ We calculate benefits as the benefits to the distributor of financing the underspend since the amount of the underspend can be put to some other income generating use during the period. Losses are similarly calculated as the financing cost to the distributor of the overspend.

²²⁴ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 5–9.

²²⁵ NER, cl. 6.5.8A(e).

²²⁶ NER, cl. 6.4A(a); the capex criteria are set out in cl. 6.5.7(c) of the NER.

²²⁷ NER, cl.6.5.8A(c).

²²⁸ NER, cl. 6.5.7(a).

3.3.3 Reasons for AER's preliminary position

We propose to apply the CESS to the Victorian distributors in the next regulatory control period as we consider this will contribute to the capex incentive objective.

The Victorian distributors are currently subject to a CESS. As part of our Better Regulation program we consulted on and published version 1 of the capex incentives guideline which sets out the CESS.²²⁹ The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.²³⁰ We are also proposing to apply forecast depreciation, which we discuss further in chapter 5. In developing the CESS we took into account the capex incentive objective, capex criteria, capex objectives, and the CESS principles. We also developed the CESS to work alongside other incentive schemes that apply to distributors including the EBSS, STPIS and DMIS.

For capex, the sharing of underspends and overspend amounts happens at the end of each regulatory control period when we update a distributor's RAB to include new capex. If a distributor spends less than its approved forecast during a period, it will benefit within that period. Consumers benefit at the end of that period when the RAB is updated to include less capex compared to if the business had spent the full amount of the capex forecast. This leads to lower prices in the future.

Without a CESS, the incentive for a distributor to spend less than its forecast capex declines throughout the period.²³¹ Because of this a distributor may choose to spend capex earlier, or spend on capex when it may otherwise have spent on opex, or less on capex at the expense of service quality—even if it may not be efficient to do so.

With the CESS, a distributor faces the same reward and penalty in each year of a regulatory control period for capex underspends or overspends. The CESS will provide a distributor with an ex ante incentive to spend only efficient capex in each year of the regulatory control period. A distributor that makes an efficiency gain will be rewarded through the CESS. Conversely, a distributor that makes an efficiency loss will be penalised through the CESS. In this way, a distributor will be more likely to incur only efficient capex when subject to a CESS, so any capex included in the RAB is more likely to reflect the capex criteria. In particular, if a distributor is subject to the CESS, its capex is more likely to be efficient and to reflect the costs of a prudent distributor.

In addition, when the CESS, EBSS and STPIS apply to a distributor, incentives for opex, capex and service performance are balanced. This encourages a distributor to make efficient decisions on when and what type of expenditure to incur, and to balance expenditure efficiencies with service quality.

Relevantly, as emphasised as part of the development of our guideline, while our forecast of capex for a regulatory control period is partly informed by our forecast of the prudent and

²²⁹ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 5–9.

²³⁰ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

²³¹ As the end of the regulatory period approaches, the time available for the distributor to retain any savings gets shorter. So the earlier a distributor incurs an underspend in the regulatory period, the greater its reward will be.

efficient capex the network service provider will need to complete discrete projects or programs this is only to inform our total forecast of capex for the regulatory control period. Importantly, while we may consider certain projects and programs in forming a view on the total capex forecast, we do not determine which projects and programs the network service provider should or should not undertake. This is consistent with the incentive based regulatory framework.

Once we approve total revenue, the network service provider is able to prioritise its capex program given its circumstances over the course of the regulatory control period. This means, a network service provider may choose to defer some discrete projects that we initially considered when forming our view of the total capex forecast for the regulatory control period. Conversely, it may also choose to bring forward other discrete projects that we had not previously assessed when setting the network service provider's forecast of capex for the regulatory control period. This means that it is not appropriate to consider our determinations as approving specific projects and programs.

3.4 Demand management incentive scheme and demand management innovation allowance mechanism

We established a new demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIAM) in December 2017.²³² It is intended that the new DMIS and DMIAM are to apply to the Victorian distributors in the 2021–25 regulatory control period.

The DMIS is intended to encourage distribution businesses to find lower cost solutions to investing in network solutions. The incentive scheme achieves this by encouraging distribution businesses to undertake efficient expenditure on non-network options relating to demand management.

We have also improved our existing DMIA to provide a research and development (R&D) fund to help distribution businesses discover new ways of using demand management to keep the costs down for electricity consumers in the future. Its objective is to provide distribution businesses with funding for R&D in demand management projects that have the potential to reduce long term network costs. This will fund innovative projects that have the potential to deliver ongoing reductions in demand or peak demand.

3.4.1 AER's preliminary position

We intend to apply our new DMIS and DMIAM as published by us in December 2017 to apply to the Victorian distributors in the 2021–25 regulatory control period.

3.4.2 Reasons for AER's preliminary position

²³² <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism>

Distribution businesses can manage demand on their networks to reduce, delay or even avoid the need to install, replace or upgrade expensive network assets. Network assets include equipment like poles, wires, transformers and substations. When used effectively, managing demand to avoid incurring these costs can reduce upward pressure on network charges, which make up about half the cost of electricity bills.

Managing demand on electricity networks can increase the reliability of supply and reduce the cost of supplying electricity. Often, electricity consumers are empowered to manage demand via price signals and enabling technology.

Price signals or financial incentives can reward consumers for using electricity in a way that allows network businesses to keep their costs down. These signals or incentives may come in the form of things like cost-reflective tariffs, congestion pricing, and rebates. Enabling technology often complements price signals by empowering consumers' use of electricity in a way that allows network businesses to keep their costs down. This technology may include things like advanced metering technology, demand response enabling devices, and energy monitoring apps.

The revised DMIS only provides incentives for the implementation of demand management projects that are efficient and contribute, partially or wholly, to resolving a network constraint. In deciding whether a project is efficient, we require distribution businesses to test the demand management services market. This will increase transparency, promote competition and put downwards pressure on electricity prices. This is because distribution business can only benefit from incentives if they address the network constraint in the most efficient way available.

This incentive structure should encourage best-practice network planning that will deliver value to consumers via lower electricity prices. We believe our incentive scheme will achieve this because distribution businesses will be:

- Selecting efficient projects that deliver the most value to consumers when solving network constraints, regardless of whether these projects constitute a demand-side or supply-side solution.
- Asking third parties to propose demand management solutions, and forming contracts with parties that propose solutions that deliver the most value to consumers.

We will continue providing a demand management innovation allowance, which is a R&D fund, because the innovation allowance will complement the new DMIS. It will increase the capacity of distribution business to invest in ideas that may eventually form parts of projects under the incentive scheme.

We believe that the DMIS, supported by the DMIAM, will provide long term benefit to customers.

3.4.3 AER's assessment approach to the DMIS

We will assess the proposed projects under the DMIS and DMIAM under the assessment criteria prescribed by the scheme documents.

3.5 Victoria F-factor scheme

On 22 December 2016, the Victorian Government published the “f-factor scheme order 2016” (the 2016 Order), which revoked the previous 2011 f-factor scheme Order. Instead of the previous calendar year measurement method, the new f-factor scheme now measures fire starts on a financial year basis to coincide with the fire season.

The new f-factor scheme targets incentives towards fire ignitions that pose the greatest risk of harm via ignition risk units (IRUs). The key difference between the new and the current scheme is that each fire is weighted by a “location factor” and a “fire risk (timing) factor”. By applying these weighting factors to each fire, the fire will have a score called an “IRU”. These factors and their inputs are all prescribed by the Order.

3.5.1 AER's preliminary position

We intend to continue to apply the Victoria f-factor scheme as set out in the 2016 Order to the Victorian distributors in the 2021–25 regulatory control period.

The IRU targets for relevant financial years have been set by the 2016 Order.²³³ If the Order remains unchanged,²³⁴ the IRU target for each financial year of the forthcoming period are:

AusNet	CitiPower	Jemena	Powercor	United Energy
221.1	3.4	9.7	412.8	22.3

Source: Clause 10 (1), the Order.

3.5.2 Reasons for AER's preliminary position

The new f-factor scheme seeks to incentivise better alignment between the bushfire risk reduction practices and priorities of the distribution businesses and the bushfire risk exposure of the Victorian community posed by the distribution network.²³⁵

The new scheme will still provide a symmetrical scheme in terms of rewards or penalties - a revenue adjustment - with respect to the historical performance. However, the benchmark targets for fire starts will be measured differently as will the calculation of reward or penalty amounts.

3.5.3 AER's assessment approach

Under the new scheme, the revenue adjustment is to be arrived at by applying an incentive rate to an IRU target subtracted for pass performance in the form of an IRU amount.²³⁶ The

²³³ Under clause 10(3) of the Order

²³⁴ Under clause 10(2) of the Order, the Minister may modify the IRU targets by modifying the Order.

²³⁵ Victorian Department of Environment Land Water and Planning, *f-factor Incentive Scheme: Regulatory Impact Statement*, October 2016, p. 15.

²³⁶ Cl. 9, *National Electricity (Victoria) Act 20005, F-Factor Scheme Order 2016*, G51, 22 December 2016

f-factor scheme requires the AER to determine the IRU amount.²³⁷ The incentive rate and IRU target are prescribed.²³⁸

Under the new scheme, distributors will prepare a fire start report each year. Energy Safe Victoria (ESV) will then review this and verify the accuracy of the fire start reports. After this process, ESV will advise the AER on whether the reports are accurate; and if they are not accurate, the relevant IRU scores. We will then determine the appropriate rewards or penalties that may apply for each distributor in accordance with the incentive rate prescribed by the Order.

3.6 Small scale incentive scheme

In its negotiation with the Customer Forum, AusNet Services is considering the development of an incentive scheme to improve customer satisfaction for connections, planned and unplanned outages and complaint handling.

The NER allows for us to develop a Small Scale Incentive Scheme (SSIS) to provide for incentives not already covered by the existing incentive schemes under the NER and to test innovative approaches to incentives.²³⁹ For example, a SSIS can provide rewards for NSPs which engage more effectively with consumers.²⁴⁰

3.6.1 AER's preliminary position

We would be open to developing a SSIS to apply in the 2021-25 regulatory control period if the scheme meets the requirements of the NER. We may trial a SSIS without penalties or rewards.

At this stage we do not consider that a SSIS should apply to Citipower, Jemena, Powercor or United Energy.

3.6.2 Reasons for preliminary position

We consider that the development of a SSIS could potentially benefit customers and we are open to AusNet proposing such a scheme. However, there are requirements under the NER to which we must adhere when developing a SSIS. We outline these requirements in section 3.6.3.

²³⁷ Cl. 11, *National Electricity (Victoria) Act 20005, F-Factor Scheme Order 2016*, G51, 22 December 2016

²³⁸ See cl. 9(4)(ii) and 9(4)(iii), *National Electricity (Victoria) Act 20005, F-Factor Scheme Order 2016*, G51, 22 December 2016

²³⁹ AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, November 2012, pp. 13, 212.

²⁴⁰ AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, November 2012, p. 212.

The rules provide for the AER to trial a SSIS without applying penalties or rewards.²⁴¹ Given that this is the first time that we would apply such a scheme, we may well consider it prudent to trial a SSIS without penalties or rewards.

We currently do not consider that a SSIS should apply to CitiPower, Jemena, Powercor or UED because they have not proposed the application of such schemes. AusNet and the Customer Forum are negotiating with specific reference to the data that AusNet collects on customer satisfaction.²⁴²

3.6.3 AER's assessment approach

In developing a SSIS the AER must adhere to the requirements of the NER. Clause 6.6.4(b) of the NER sets out the matters which we must have regard to when developing a small scale incentive scheme:

- DNSPs should be rewarded or penalised for efficiency gains or losses in respect of their distribution systems;
- the rewards and penalties should be commensurate with the efficiency gains or efficiency losses in respect of a distribution system, but a reward for efficiency gains need not correspond in amount to a penalty for efficiency losses;
- the benefits to electricity consumers that are likely to result from efficiency gains in respect of a distribution system should warrant the rewards provided under the scheme, and the detriments to electricity consumers that are likely to result from efficiency losses in respect of a distribution system should warrant the penalties provided under the scheme;
- the interaction of the scheme with other incentives that a distribution network service provider may have under the Rules; and
- the capital expenditure objectives and the operating expenditure objectives.²⁴³

The NER requires that the introduction of a new SSIS involve wider consultation with all stakeholders in the NEM. Arguably, a scheme targeted just to the preferences of AusNet's customers might not generate much interest with wider stakeholders. Nonetheless, it might not be possible for a robust new scheme to be developed in time to be accommodated in the negotiation process, so the Customer Forum might just seek a commitment from AusNet to prepare a proposal to send to the AER for consideration. The Forum could also propose implementing a new incentive scheme as a paper trial, which might provide useful information for implementing a revenue-at-risk mechanism at some point in the future.

²⁴¹ NER, cl. 6.6.4(e)

²⁴² AusNet, *Customer Experience Negotiating position for the Customer Forum*, August 2018, pp. 5-11.

²⁴³ NER, cl. 6.6.4(b)

4 Expenditure forecast assessment guideline

This chapter sets out our intention to apply our expenditure forecast assessment guideline (the EFA guideline)²⁴⁴ including the information requirements applicable to the Victorian electricity distribution network service providers for the 2021–25 regulatory control period. The EFA guideline sets out our expenditure forecast assessment approach developed and consulted upon during the Better Regulation program. It outlines the assessment techniques we will use to assess a distributor's proposed expenditure forecasts, and the information we require from the distributor.

The EFA guideline uses a nationally consistent reporting framework that allows us to compare the relative efficiencies of distributors and decide on efficient expenditure forecasts. The NER requires Victorian electricity distributors to advise us by 31 December 2018 of the methodology they propose to use to prepare their forecasts.²⁴⁵ In the final F&A we must advise whether we will deviate from the EFA guideline.²⁴⁶ This will provide clarity on how we will apply the EFA guideline and the information the Victorian electricity distributors should include in their regulatory proposals. This contributes to an open and transparent process and makes our assessment of expenditure forecasts more predictable. The EFA guideline contains a suite of assessment/analytical tools and techniques to assist our review of the expenditure forecasts that distributors include in their regulatory proposals. We intend to have regard to the assessment tools set out in the guideline. The tool kit includes:

- models for assessing proposed replacement and augmentation capex
- benchmarking (including broad economic techniques and more specific analysis of expenditure categories)
- methodology, governance and policy reviews
- predictive modelling and trend analysis
- cost benefit analysis and detailed project reviews.²⁴⁷

We exercise judgement to determine the extent to which we use a particular technique to assess a regulatory proposal. We use the techniques we consider appropriate depending on the specific circumstances of the determination. The guideline is flexible and recognises that we may employ a range of different estimating techniques to assess an expenditure forecast.

For opex, in most cases we take a base-step-trend approach to assessing forecast expenditure and in this context use top down economic benchmarking tools to determine the reasonableness of the forecast rather than a bottom-up assessment approach. However, in

²⁴⁴ We were required to develop the EFA guideline under clauses 6.4.5 and 11.53.4 of the NER. We published the guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.

²⁴⁵ NER, cl. 6.8.1A(b)(1).

²⁴⁶ NER, cl. 6.8.1(b)(2)(viii).

²⁴⁷ AER, *Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution*, 29 November 2013.

exercising our judgement, we may use any analytical tool at our disposal, including assessing individual elements of the forecast using a bottom-up approach.

We will continue to develop and use economic benchmarking to inform our expenditure decisions consistent with the EFA guideline. Economic benchmarking remains a tool in assessing the relative efficiency of network services providers. We are likely to use a range of benchmarking approaches in assessing expenditure forecasts. Benchmarking also provides a source of information to assist both service providers and other interested parties about the relative productivity of individual businesses and the trends in productivity for the industry.

In the context of continuously improving economic benchmarking, we are currently reviewing and refining our analysis of operating environment factors in consultation with industry and other interested parties. The review will be finalised in 2018.²⁴⁸ We will then seek to implement any recommended improvements from that process in our annual benchmarking and regulatory determination processes.

²⁴⁸ More information is available at <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-operating-environment-factors-for-distribution-network-service-providers>.

5 Depreciation

As part of the process of rolling forward a distributor's RAB to the start of the next regulatory control period, we update the RAB for actual capex incurred during the current regulatory control period and also adjust for depreciation. This chapter sets out our preliminary approach on the form of depreciation to be used when the Victorian distributors' RABs are rolled forward to the commencement of the 2026–30 regulatory control period.

The depreciation we use to roll forward the RAB can be based on either:

- Actual capex incurred during the regulatory control period (actual depreciation). We roll forward the RAB based on actual capex less the depreciation on the actual capex incurred by the distributor; or
- The capex allowance forecast at the start of the regulatory control period (forecast depreciation). We roll forward the RAB based on actual capex less the depreciation on the forecast capex approved for the regulatory control period.

The choice of depreciation approach is one part of the overall capex incentive framework.

Consumers benefit from improved efficiencies through lower regulated prices. Where a CESS is applied, using forecast depreciation maintains the incentives for distributors to pursue capex efficiencies, whereas using actual depreciation would increase these incentives. There is more information on depreciation as part of the overall capex incentive framework in our capex incentives guideline.²⁴⁹ In summary:

- If there is a capex overspend, actual depreciation will be higher than forecast depreciation. This means that the RAB will increase by a lesser amount than if forecast depreciation was used. As a result, the distributor will earn less revenue into the future (i.e. it will bear more of the cost of the overspend into the future) than if forecast depreciation had been used to roll forward the RAB.
- If there is a capex underspend, actual depreciation will be lower than forecast depreciation. This means that the RAB will increase by a greater amount than if forecast depreciation was used. Hence, the distributor will earn greater revenue into the future (i.e. it will retain more of the benefit of an underspend into the future) than if forecast depreciation had been used to roll forward the RAB.

The incentive from using actual depreciation to roll forward the RAB also varies with the life of the asset. Using actual depreciation will provide a stronger incentive for the distributor to underspend capex on shorter lived assets compared to longer lived assets as this will lead to a relatively larger increase in the RAB. Use of forecast depreciation, on the other hand, leads to the same incentive for capex regardless of asset lives. This is because using forecast depreciation does not affect the distributor's incentive on capex as the distributor does not lose the full cost of any overspend and is not able to keep all the benefits of any

²⁴⁹ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

underspend. To this end, using forecast depreciation means the capex incentive is focussed on the return on capital.

5.1 AER's preliminary position

Our preliminary position is to continue using the forecast depreciation approach to establish the RAB at the commencement of the 2026–30 regulatory control period for the Victorian distributors. We consider this approach will provide sufficient incentives for the Victorian distributors to achieve capex efficiency gains over the 2021–25 regulatory control period.

5.2 AER's assessment approach

In our distribution determination we have to decide whether we will use actual or forecast depreciation to establish a distributor's RAB at the commencement of the following regulatory control period.²⁵⁰

We set out in our capex incentives guideline our process for determining which form of depreciation we propose to use in the RAB roll forward process.²⁵¹ Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:²⁵²

- any other incentives the service provider has to undertake efficient capex
- substitution possibilities between assets with different lives
- the extent of overspending and inefficient overspending relative to the allowed forecast
- the capex incentive guideline
- the capital expenditure factors.

5.3 Reasons for AER's preliminary position

Consistent with our capex incentives guideline, we propose to continue using the forecast depreciation approach to establish the RAB for the Victorian distributors at the commencement of the 2026–30 regulatory control period. We note AusNet Services and Jemena proposed this approach in their request to replace the current F&A.²⁵³

We had regard to the relevant factors in the NER in developing the approach for deciding on the form of depreciation set out in our capex incentives guideline.²⁵⁴

Our approach is to apply forecast depreciation except where:

²⁵⁰ NER, cl. S6.2.2B.

²⁵¹ NER, cl. 6.4A(b)(3).

²⁵² NER, cl. S6.2.2B.

²⁵³ AusNet Services, *Victorian Electricity Distribution Determination 2021-25: Request to replace Framework and Approach*, 30 April, p. 6; Jemena Electricity Networks (Vic) Ltd, *Request for a replacement Framework and Approach*, 30 April 2018, p. 9.

²⁵⁴ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

- there is no CESS in place and therefore the power of the capex incentive may need to be strengthened, or
- a distributor's past capex performance demonstrates evidence of persistent overspending or inefficiency, thus requiring a higher powered incentive.

In making our decision on whether to use actual depreciation in either of these circumstances we will consider:

- the substitutability between capex and opex and the balance of incentives between these
- the balance of incentives with service outcomes
- the substitutability of assets with different asset lives.

We have chosen forecast depreciation as our default approach because, in combination with the CESS, it will provide a 30 per cent reward for capex underspends and 30 per cent penalty for capex overspends, which is consistent for all types of asset categories. In developing our capex incentives guideline, we considered this to be a sufficient incentive for a distributor to achieve efficiency gains over the regulatory control period in most circumstances.

The opening RAB at the commencement of the 2021–25 regulatory control period will be established using forecast depreciation, as stated in our previous determination that applies to the Victorian distributors for the 2016–20 regulatory control period. The use of forecast depreciation to establish the opening RAB for the commencement of the 2026–30 regulatory control period therefore maintains the current approach. The Victorian distributors are currently subject to a CESS and we propose to continue applying the CESS in the 2021–25 regulatory control period. We discuss this in section 3.3.

For the Victorian distributors, we consider the incentive provided by the application of the CESS in combination with the use of forecast depreciation and our other ex post capex measures should be sufficient to achieve the capex incentive objective.²⁵⁵ Our ex post capex measures are set out in the capex incentives guideline. The guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective.

²⁵⁵ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 13–19 and 20–21.

Appendix A: Rule requirements for classification

We must have regard to four factors when classifying distribution services.²⁵⁶

1. the form of regulation factors in section 2F of the NEL:
 - the presence and extent of any barriers to entry in a market for electricity network services
 - the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other electricity network service provided by the network service provider
 - the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other service provided by the network service provider in any other market
 - the extent to which any market power possessed by a network service provider is, or is likely to be, mitigated by any countervailing market power possessed by a network service user or prospective network service user
 - the presence and extent of any substitute, and the elasticity of demand, in a market for an electricity network service in which a network service provider provides that service
 - the presence and extent of any substitute for, and the elasticity of demand in a market for, electricity or gas (as the case may be)
 - the extent to which there is information available to a prospective network service user or network service user, and whether that information is adequate, to enable the prospective network service user or network service user to negotiate on an informed basis with a network service provider for the provision of an electricity network service to them by the network service provider.²⁵⁷
2. the form of regulation (if any) previously applicable to the relevant service or services, and, in particular, any previous classification under the present system of classification or under the present regulatory system (as the case requires)²⁵⁸
3. the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)²⁵⁹
4. any other relevant factor.²⁶⁰

We must have regard to six factors when classifying direct control services as either standard control or alternative control services.²⁶¹

²⁵⁶ NER, cl. 6.2.1(c).

²⁵⁷ NEL, s. 2F.

²⁵⁸ NER, cl. 6.2.1(c)(2).

²⁵⁹ NER, cl. 6.2.1(c)(3).

²⁶⁰ NER, cl. 6.2.1(c)(4).

1. the potential for development of competition in the relevant market and how the classification might influence that potential
2. the possible effects of the classification on administrative costs of us, the distributor and users or potential users
3. the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made
4. the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction)
5. the extent that costs of providing the relevant service are directly attributable to the customer to whom the service is provided, and
6. any other relevant factor.²⁶²

In classifying direct control services that have previously been subject to regulation under the present or earlier legislation, we must also follow the requirements of clause 6.2.2(d) of the NER.

²⁶¹ NER, cl. 6.2.2(c).

²⁶² NER, cl. 6.2.2(c).

Appendix B: Proposed service classification of Victorian distribution services 2021–25²⁶³

Service group	Further description	Current classification 2016-20	AER proposed – classification 2021–25
Common distribution service - use of the distribution network for the conveyance/flow of electricity (including the services relating to network integrity)			
Common distribution service (formerly 'network services')	<p>The suite of activities that includes, but is not limited to, the following:</p> <ul style="list-style-type: none"> the planning, design, repair, maintenance, construction, and operation of the distribution network works to fix damage to the network (including recoverable works caused by a customer or third party) support for another network during an emergency event procurement and provision of network demand management activities for distribution or system reliability, efficiency or security purposes activities related to 'shared asset facilitation' of distributor assets²⁶⁴ 	Standard control	Standard control

²⁶³ The examples and activities listed in the 'Further description' column are not intended to be an exhaustive list and some distributors may not offer all activities listed. Rather the examples provide a sufficient indication of the types of activities captured by the service.

²⁶⁴ Revenue for these services is charged to the relevant third party and is treated in accordance with the shared asset guideline. 'Shared asset facilitation' refers to administrative costs. It does not refer to the costs associated with providing the unregulated service itself.

- emergency disconnect for safety reasons and work conducted to restore a failed component of the distribution system to an operational state upon investigating a customer outage
- establishment and maintenance of National Metering Identifiers (NMIs) in market and/or network billing systems, and other market and regulatory obligations
- ongoing inspection of private electrical networks (not part of the shared network) required under legislation for safety reasons²⁶⁵
- supply abolishment of basic connection²⁶⁶
- customer safety information, e.g. 'dial before you dig' services
- Bulk supply point metering - activities relating to monitoring the flow of electricity through the distribution network.
- DNSP contribution to third-party initiated network asset relocations/re-arrangements under ESCV Guideline 14.²⁶⁷

Network ancillary services – customer and third party initiated services related to common distribution services

Access permits, oversight and facilitation	<p>Activities include:</p> <ul style="list-style-type: none"> • a distributor issuing access permits or clearances to work to a person authorised to work on or near distribution systems including high and low voltage • a distributor issuing confined space entry permits and associated safe 	Unclassified	Alternative control
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²⁶⁵ The Victorian Electricity Safety Act 1998, clause 113F, requires Vic DNSPs to inspect overhead private electric lines.

²⁶⁶ This service is classified as Standard Control Services under the 2016-20 Determination for public safety reasons. Victorian DNSPs wish to continue with the classification.

²⁶⁷ This classification applies where a customer contribution is calculated and applied in accordance with Essential Services Commission (ESCV) Guideline 14 or where a customer contribution is calculated and applied in accordance with any other relevant Victorian legislation or regulation, including regulations made under the National Electricity (Victoria) Act, 2005. The party requesting such works under this classification must pay the net cost of the works, subject to any rebates specified in Guideline 14 or by any other relevant Victorian legislation or regulation.

	<p>entry equipment to a person authorised to enter a confined space</p> <ul style="list-style-type: none"> • a distributor providing access to switch rooms, substations and other network equipment to a non-Local Network Service Provider party who is accompanied and supervised by a distributor's staff member. May also include a distributor providing safe entry equipment (fall-arrest) to enter difficult access areas. • specialist services (which may involve design related activities and oversight/inspections of works) where the design or construction is non-standard, technically complex or environmentally sensitive and any enquiries related to distributor assets • facilitation of generator connection and operation of the network • facilitation of activities within clearances of distributor's assets, including physical and electrical isolation of assets. 		
Sale of approved materials or equipment	Includes the sale of approved materials/equipment to third parties for connection assets that are gifted back to become part of the shared distribution network.	Unclassified	Alternative control
Notices of arrangement and completion notices	<p>Examples include:</p> <ul style="list-style-type: none"> • Work of an administrative nature where a local council requires evidence in writing from the distributor that all necessary arrangements have been made to supply electricity to a development. This includes: receiving and checking subdivision plans, copying subdivision plans, checking and recording easement details, assessing supply availability, liaising with developers if errors or changes are required, and preparing notifications of arrangement. • Provision of a completion notice (other than a notice of arrangement). This applies where the real estate developer requests the distributor to provide documentation confirming progress of work. Usually associated with discharging contractual arrangements (e.g. progress payments) to meet contractual undertakings. 	Unclassified	Alternative control

Network related property services	<p>Activities include:</p> <ul style="list-style-type: none"> • Network related property services such as property tenure services relating to providing advice on, or obtaining: deeds of agreement, deeds of indemnity, leases, easements or other property tenure in relation to property rights associated with a connection or relocation. • Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer. 	Unclassified	Alternative control
Network safety services	<p>Examples include:</p> <ul style="list-style-type: none"> • provision of traffic control and safety observer services by the distributor where required • fitting of tiger tails, possum guards, and aerial markers • high load escorts. • site visit relating to location of underground cables/assets 	Alternative control	Alternative control
Planned Interruption – customer requested amendment	<p>Examples include:</p> <ul style="list-style-type: none"> • where the customer requests to move a distributor planned interruption and agrees to fund the additional cost of performing this distribution service outside of normal business hours 	Unclassified	Alternative control
Customer requested supply outage	<p>Examples include:</p> <ul style="list-style-type: none"> • customer initiated network outage (e.g. to allow customer and/or contractor to perform maintenance on the customer’s assets, work close to or for safe approach, which impacts other networks users). 	Unclassified	Alternative control
Inspection and auditing services	<p>Activities include:</p> <ul style="list-style-type: none"> • inspection and reinspection by a distributor, of gifted assets or assets that have been installed or relocated by a third party 	Alternative control	Alternative control

- investigation, review and implementation of remedial actions that may lead to corrective and disciplinary action of a third party service provider due to unsafe practices or substandard workmanship
- auditing of a third party service provider's work practices in the field
- re-test at a customer's installation, where the installation fails the initial test and cannot be connected.

Provision of training to third parties for network related access	Training services provided to third parties that result in a set of learning outcomes that are required to obtain a distribution network access authorisation specific to a distributor's network. Such learning outcomes may include those necessary to demonstrate competency in the distributor's electrical safety rules, to hold an access authority on the distributor's network and to carry out switching on the distributor's network. Examples of training might include high voltage training, protection training or working near power lines training.	Unclassified	Alternative control
Authorisation and approval of third party service providers design, work and materials	<p>Activities include:</p> <ul style="list-style-type: none"> • authorisation or re-authorisation of individual employees and subcontractors of third party service providers and additional authorisations at the request of the third party service providers (excludes training services) • acceptance of third party designs and works • assessing an application from a third party to consider approval of alternative material and equipment items that are not specified in the distributor's approved materials list 	Alternative control	Alternative control
Security lights	<p>Provision, installation, operation, and maintenance of equipment mounted on distribution equipment used for security services, e.g. nightwatchman lights.</p> <p>Note: excludes connection services.</p>	Unclassified	Alternative control
Customer requested provision	Data requests by customers or third parties including requests for the	Unclassified	Alternative control

of electricity network data provision of electricity network data or consumption data outside of legislative obligations.

Third party requested network alterations or other improvements	Alterations or other improvements to the shared distribution network to enable third party infrastructure (e.g. NBN Co telecommunications assets) to be installed on the shared distribution network. This does not relate to upstream distribution network augmentation.	Alternative control	Alternative control
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Metering services - activities relating to the measurement of electricity supplied to and from customers through the distribution system (excluding network meters)

Type 1 to 4 metering services	Type 1 to 4 metering installations ²⁶⁸ and supporting services are competitively available.	Unregulated	Unregulated
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Type 5 and 6 (inc. smart metering) services where the distributor remains responsible	Includes: <ul style="list-style-type: none"> Recovery of the cost of type 5 and 6 metering equipment²⁶⁹ including communications network (including meters with internally integrated load control devices). Testing, inspecting, investigating, maintaining or altering existing type 5 or 6 metering installations or instrument transformers. Quarterly or other regular reading of a metering installation. Metering data services that involve the collection, processing, storage and delivery of metering data, the provision of metering data from the previous two years, remote or self-reading at difficult to access sites, and the management of relevant NMI Standing Data in accordance with the NER. 	Alternative control	Alternative control
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Auxiliary metering services	Activities include:	Alternative control	Alternative control
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²⁶⁸ Includes the instrument transformer, as per the definition of a 'metering installation' in Chapter 10 of the NER.

²⁶⁹ Includes the instrument transformer, as per the definition of a 'metering installation' in Chapter 10 of the NER.

(type 5 and 6 including smart metering) where the distributor remains responsible	<ul style="list-style-type: none"> • requests to test, inspect and investigate, or alter an existing type 5 or 6 metering installation • testing and maintenance of instrument transformers for type 5 and 6 metering purposes • Non-standard metering services for Type 5 to 7 meters and any other meter types introduced. • works to re-seal a type 5 or 6 meter due to customer or third party action (e.g. by having electrical work done on site) • change distributor load control relay channel on request that is not a part of the initial load control installation, nor part of standard asset maintenance or replacement. • Remote de-energisation and re-energisation • Remote meter configuration • Field based special meter read • Office based special meter read 		
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Type 7 metering services	Administration and management of type 7 metering installations in accordance with the NER and jurisdictional requirements. Includes the processing and delivery of calculated metering data for unmetered loads, and the population and maintenance of load tables, inventory tables and on/off tables.	Alternative control	Alternative control
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Connection services²⁷⁰ - services relating to the electrical or physical connection of a customer to the network

Basic connection services	Means a <i>connection service</i> ²⁷¹ related to a <i>connection</i> (or a proposed	Alternative control	Alternative control
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²⁷⁰ When discussing connections, we must consider how connection policies and chapter 5A of the NER impact the regulation of connection services. For this reason, we will not be able to completely address the classification of connection services in the classification guideline.

connection) between a *distribution system* and a *retail customer's* premises (excluding a non-registered *embedded generator's* premises) in the following circumstances:

(a) either:

1. the *retail customer* is typical of a significant class of *retail customers* who have sought, or are likely to seek, the service; or
2. the *retail customer* is, or proposes to become, a *micro embedded generator*, and

(b) the provision of the service involves minimal or no *augmentation* of the *distribution network*; and

(c) a *model standing offer* has been approved by the AER for providing that service as a *basic connection service*.

Standard connection service	Means a connection service (other than a basic connection service) for a particular class (or sub-class) of connection applicant and for which a model standing offer has been approved by the AER.	Standard control	Standard control
Negotiated connection	Means a connection service (other than a basic connection service) for which a DNSP provides a connection offer for a negotiated connection contract. This includes connections under Chapter 5 of the NER.	Standard control	Standard control
Connection application and management services	Works initiated by a customer or retailer which are specific to the connection point. This includes, but is not limited to: <ul style="list-style-type: none"> • field based de-energisation²⁷² and re-energisation • Non basic supply abolishment or reposition non-basic connection 	Alternative control	Alternative control

²⁷¹ Italics denotes definitions in Chapter 5A of the NER.

²⁷² De-energisation services related to business as usual activities and de-energisation services that may relate to changing over meter types

- Temporary connections (e.g. for builder's supply, fetes etc.)
- overhead service line replacement – customer requests the existing overhead service to be replaced (e.g. as a result of a point of attachment relocation). No material change to load
- protection and power quality assessment
- customer requested change requiring primary and secondary plant studies for safe operation of the network (e.g. change protection settings)
- upgrade from overhead to underground service
- rectification of illegal connections or damage to overhead or underground service cables
- assessing connection applications or a request to undertake relocation of network assets as contestable works and preparing offers
- processing preliminary enquiries requiring site specific or written responses
- undertaking planning studies and associated technical analysis (e.g. power quality investigations) to determine suitable/feasible connection options for further consideration by applicants
- liaising with groups representing multiple connecting parties (e.g. community group upgrades)
- site inspection in order to determine the nature of the connection service sought by the connection applicant and ongoing co-ordination for large projects
- registered participant support services associated with connection arrangements and agreements made under Chapter 5 of the NER.

Enhanced connection services

Other or enhanced connection services provided at the request of a customer or third party that include those that are:

- provided with higher quality of reliability standards, or lower quality of

Alternative control/
negotiated/
unclassified

Alternative control

reliability standards (where permissible) than required by the NER or any other applicable regulatory instruments. This includes reserve feeder installation and maintenance.

- in excess of levels of service or plant ratings required to be provided by the distributor

Public lighting - lighting services provided in connection with a distribution network

Public lighting	<ul style="list-style-type: none"> • Operation, maintenance, repair and replacement public lighting services • Alteration and relocation of public lighting assets • New public lighting services incl. greenfield sites & new light types (distributor provided) • Provision, construction and maintenance of emerging public lighting technology. 	Alternative control/ negotiated	Alternative control
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