Other step changes

PAL RRP BUS 9.06 - Other step changes - Dec2020

Revised regulatory proposal 2021–2026

Contents

1 Summary

1.1 Summary our revised proposal

In our revised proposal, we accept:

- the draft determination to accept our five-minute settlement and the IT cloud mitigation step changes
- the draft determination to not to accept as step changes the expenditure associated with the replacement of expulsion drop-out (**EDO**) fuses, Energy Safe Victoria (**ESV**) levy and the financial year regulatory information notice (RIN).

However, in response to the draft determination, we:

- update the value of our security of critical infrastructure step change based on a recent market test
- continue to propose a step change for our solar enablement program
- continue to propose a step change for increasing insurance premiums, and in doing so update our forecasts for the proposed step change based on our actual 2020/21 policy year premiums
- propose a preferred calculation methodology for our rapid earth fault current limiter (**REFCL**) on-going costs
- propose the recovery of Energy Safe Victoria (**ESV**) levy and the Australian Energy Market Operator (**AEMO**) participant fees through the B-factor of the standard control services control mechanism, refer to appendix PAL RRP APP08.

This business case supports our operating expenditure chapter and outlines further considerations in respect of our solar enablement and REFCL on-going costs step changes. Our security of critical infrastructure step change is discussed in the PAL RRP BUS 9.01 and our insurance premiums step change is discussed in the insurance business case PAL RRP BUS 9.05 submitted with this revised proposal. We do not discuss further those aspects of the draft determination that we have accepted.

We observe at the outset that we disagree with the Australian Energy Regulator's (**AER**) approach to assessing step changes in the draft determination. We also do not consider the AER's consideration of our individual step changes delivers total operating expenditure that is reasonably required to achieve the operating expenditure objectives. The reasons for this are summarised below.

1.1.1 The AER's framework for assessing step changes does not comply with the Law and Rules

The AER's analytical framework for assessing our proposed step changes is deeply flawed. We do not consider that all relevant considerations are captured by the framework. In any event, any such framework cannot detract from the primacy of the National Electricity Rules (**Rules**). The overarching principle must always be that where step changes form part of an operating expenditure forecast that otherwise reflects each of the operating expenditure criteria, those step changes must be accepted by the AER.

A particular issue that arises in the draft determination is the rejection of step changes that do not arise from a change in regulatory obligations or an efficient substitution of capital expenditure with operating expenditure (**capex/opex trade-off**) on the basis that the expenditure is not 'material'. The AER's approach has no basis in the National Electricity Law (**Law**) or Rules because:

- there is no express materiality threshold under the Rules for the purposes of assessing whether operating expenditure should be included in the forecast
- there is no basis in the Rules for applying a materiality threshold to operating expenditure step changes in circumstances where we are an efficient distributor facing a range of other pressures on our operating expenditure in the next regulatory period, including:

  - a negative productivity adjustment, which reduces our total operating expenditure allowance
  - real non-labour price growth of zero, which means that the non-labour component of price growth is equal only to the consumer price index (**CPI**)
  - the enduring impact of COVID-19, which (other things being equal) increases costs of network services
  - the rejection by the AER of a number of other step changes we proposed, which costs will thus need to be absorbed
- there is no upward bias in our operating expenditure proposal as there are no matters that would warrant a negative step changes that are not reflected in our revised proposal.

Finally, the AER's approach to assessing proposed step changes based on materiality would create perverse incentives where smaller networks are compensated for relatively larger cost increases, while larger networks are not compensated for minimising cost increases.

Our specific concerns with the AER's assessment of the step changes which are the subject of this business case are summarised below.

Solar enablement

The draft determination regarding our solar enablement step change fails to recognise that our solar enablement program represents an efficient capex/opex trade-off. This is a fundamental flaw in the draft determination and has the consequence that the AER fails to take into account the benefits of continuing to defer capital expenditure associated with increasing distributed energy resources connected to our network or provide us with the opportunity to recover the costs associated with allowing this expenditure to be deferred. The AER's approach represents a perverse incentive to distributors to proceed with capital expenditure even where it can be efficiently deferred.

The AER also errs in its conclusion that our tapping expenditure is immaterial and captured by the rate of change. Given the step change constitutes an efficient capex/opex trade-off, under the AER's own analytical framework, an assessment of materiality is not required. In any event, the application of a materiality threshold to individual step changes has no basis in the Law or Rules, for the reasons summarised in section 1.1.1 above.

Regarding the rate of change, as recognised by the AER, the factors that the AER considers in determining output growth fail to adequately capture the increasing growth in distributed energy resources. As a result, in order to ensure we are provided with operating expenditure that reasonably reflects the operating expenditure criteria, a step change is required to allow for our expected increases in expenditure arising from this growth.

We also do not accept that the AER's alternative tapping unit rates or the AER's assessment that the costs of our correction of non-compliant inverter settings are not justified. Neither result in an operating expenditure forecast that reasonably reflects the operating expenditure criteria.

REFCL on-going costs

We disagree with the AER's approach to calculating the REFCL on-going costs step change. The step change should be equal to forecast required operating expenditure, less any expenditure already included in the base. Our updated step change reflects this approach.

1.1.2 Summary of step changes

A summary of the step changes we are proposing (including those not addressed in the business case) is set out in table 1 below.

Table 1 Summary of our proposed step changes, $ million 2021

	Original proposal	Draft determination	Revised proposal
Total step changes	61.9	26.0	55.5

Source: Powercor

2 Background

2.1 Rules requirements

The Rules provide that a distributor must include in its building block proposal the total forecast operating expenditure for the relevant regulatory period which the distributor considers is required in order to achieve each of the following (the **operating expenditure objectives**):[1]

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services,

(iii) to the relevant extent:

(iv) maintain the quality, reliability and security of supply of standard control services; and

(v) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

Where a distributor's forecast of required operating expenditure reasonably reflects each of the operating expenditure criteria, the AER must accept the forecast.[2] The operating expenditure criteria are:

(5) the efficient costs of achieving the operating expenditure objectives; and

(6) the costs that a prudent operator would require to achieve the operating expenditure objectives; and

(7) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

In assessing a distributor expenditure forecast, the AER is required to perform its function in a manner that will, or is likely to, contribute to the achievement of the national electricity objective (**NEO**).[3] The NEO is:[4]

> *…to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> *(b) price, quality, safety and reliability and security of supply of electricity*
>
> *(c) the reliability, safety and security of the national electricity system.*

1 Rules, clause 6.5.6(a).

2 Rules, clause 6.5.6(c).

3 Law, section 16(1)(a).

4 Law, section 7.

The AER is also required to take the revenue and pricing principles into account whenever it exercises a discretion in making those parts of a distribution determination that relate to direct control services.[5] The revenue and pricing principles include:[6]

> *(d) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—*
>
> *(e) providing direct control network services; and*
>
> *(f) complying with a regulatory obligation or requirement or making a regulatory payment.*

2.2 Our original proposal

Our original proposal included the solar enablement and REFCL on-going costs operating expenditure step changes. Each of these proposed step changes are summarised briefly below.

2.2.1 Solar enablement

In our original proposal we proposed a solar enablement step change to support our exporting excess power back into the network. Incremental operational expenditure was proposed in order to:

- 'tap down' distribution transformer voltages where possible as a less expensive option to, and reduce the need, for capital investment
- undertake compliance and monitoring of customers' inverters settings as if installers fail to apply the required new inverter settings that reduce the voltage rise from exporting solar, voltage rises will be significantly higher than forecast—as a result, the full value of the net benefits will not be realised and there will be inequitable outcomes whereby customers without the inverter settings applied will be able to export more at the expense of others.

2.2.2 REFCL on-going costs

We are required to progressively install rapid earth fault current limiters (REFCLs) at 22 zone substations to comply with the *Electricity Safety Act 1998* (Vic) and the *Electricity Safety (Bushfire Mitigation) Regulations 2013* (Vic). A REFCL is a network protection device, normally installed in a zone substation, which can reduce the risk of a fallen powerline causing a fire-start.

Once an installed REFCL is commissioned and becomes operational, we must demonstrate compliance against the performance criteria to ESV annually. To ensure we meet the performance criteria, we must undertake compliance testing, re-balancing works and technical and engineering support.

For REFCLs that become operational in 2019 onwards, this will result in material incremental annual operating expenditure that is not reflected in our 2019 base operating expenditure. As such, in our original proposal we proposed a step change, for undertaking annual compliance testing, annual re-balancing works and ongoing technical and engineering support for REFCLs that become operational after 2019.

Table 2 below summarises the original proposal step change expenditure, including amended our forecast in respect of REFCL on-going costs.

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5 Law, section 16(2)(a)(i).

6 Law, section 7A(2).

Table 2 Original proposal step changes, $ million 2021

Step change	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Solar enablement	1.3	1.3	1.5	1.0	1.0	6.2
REFCL on-going costs	0.3	0.4	1.0	1.1	1.1	4.0

Source: Powercor

2.3 The draft determination

In the draft determination, the AER did not accept our solar enablement step change and the AER applied an alternative method to calculating the REFCL on-going costs step change. A summary of the AER's reasons is set out below.

2.3.1 Solar enablement

The AER accepted that, in the short term, the output growth forecast component of the rate of change may not fully account for the higher operating expenditure required for distributed energy resources management in the next regulatory period.[7] However, the AER rejected our proposed step change for solar enablement for the following reasons.

First, the AER agreed with concerns raised by its consultant, EMCa, that, having regard to the unit rates proposed by United Energy and AusNet Services, the proposed unit rate for our tapping activities should be $865 or $1,000, rather than $1,959 ($2020/21). Given the resulting reduction in operating expenditure required for our proposed tapping, the AER considered the cost of our tapping activities to be immaterial and should be managed within our total forecast operating expenditure.[8]

Secondly, the AER agreed with concerns raised by its consultant EMCa that we had not explored cost effective options to proactively ensure correct inverter settings were installed and address non-compliance or justified that a separate program to our existing business-as-usual power quality program was required.[9] Accordingly, the AER was not satisfied that this cost was sufficiently justified.

2.3.2 REFCL ongoing costs

The AER accepted that our proposed step change reflects new obligations to annual test REFCL devices once they are installed as required by the *Electricity Safety (Bushfire Mitigation) Regulations 2016* (Vic).[10] However, the AER reduced our (revised) proposed step change from $4 million to $2.6 million ($2020-21) to reflect:[11]

- the difference between the REFCL operating expenditure allowed in the final year of the 2016-20 regulatory period and the operating expenditure required in each year of the 2021-26 regulatory period
- application of the AER's forecast labour price growth (rather than our proposed labour price growth)
- updated inflation forecasts.

7 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, pp. 52-53.

8 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 53.

9 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 53.

10 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 48.

11 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 49.

3 Revised proposal

3.1 Summary of our revised proposal position

The AER's analytical framework for assessing our proposed step changes is deeply flawed. We do not consider that all relevant considerations are captured by the framework. In any event, any such framework cannot detract from the primacy of the Rules. The overarching principle must always be that where step changes form part of an operating expenditure forecast that otherwise reflects each of the operating expenditure criteria, those step changes must be accepted by the AER.

A particular issue that arises in the draft determination is the rejection of step changes that do not arise from a change in regulatory obligations or an efficient capex/opex trade off on the basis that the expenditure is not 'material'. The AER's approach has no basis in the Law or Rules.

We continue to propose a step change for our solar enablement program and provide alternative forecasts for our REFCL ongoing costs step change.

Regarding our solar enablement program, we:

- have revised our unit cost to reflect the unit rate agreed between United Energy and Zinfra, following a competitive tender process
- continue to propose our monitoring and compliance program in its original form as the success of our solar enablement program relies on new inverter settings and the only other means of ensuring compliance is costly augmentation.

Regarding our REFCL ongoing costs step change, we disagree with the AER's approach to calculating the REFCL on-going costs step change. The step change should be equal to forecast required operating expenditure, less any expenditure already included in the base.

3.2 Responding to the draft determination

3.2.1 Step changes in the AER's base-step-trend approach

In assessing a distributor's operating expenditure, the AER adopts a 'base-step-trend' approach.[12] The starting point (or 'base') is a distributor's revealed actual past operating expenditure. To account for changed economic conditions from one period to the next, the AER then applies a rate of change to 'trend' the forecast forward. The rate of change is estimated by forecasting the expected growth in input prices, outputs and productivity.

'Step changes' are then essential to account for any required operating expenditure not included in the base or trend component of the forecast. Without a step change, the distributor would otherwise not be provided with a reasonable opportunity to recover at least its efficient costs in providing direct control network services and/or complying with regulatory obligation or requirements.[13]

In addition to step changes, the AER's 2013 Expenditure Forecast Assessment Guideline also describes 'category specific forecasts', which represent:[14]

> *…an amount we may allow to be included in the opex forecast for a particular year, which is not appropriate as a step change, nor for inclusion in base opex, but which we nevertheless consider meets the legal criteria for efficient expenditure in that year.*

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[12] AER, Better regulation: Expenditure forecast assessment guideline, November 2013, p. 22.

[13] Law, sections 7A(2), 16(2)(a)(i).

[14] AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 19.

We may also use category specific forecasts to avoid inconsistency or double counting within our determination…

The AER's Expenditure Forecast Assessment Guideline only expressly recognises step changes:[15]

- resulting from the introduction of new regulatory requirements
- where a capex/opex trade-off is efficient.

In its decisions, however, the AER has recognised additional circumstances in which a step change may be required. In the last Victorian distribution reset, for example, the AER recognised that step changes may be required in situations where a change in circumstances, outside of the control of the distributor, necessitates increased expenditure to meet the operating expenditure objectives.[16]

Similarly, in the draft determination, the AER indicates that in the absence of a change in regulatory obligations or a legitimate capex/opex trade-off opportunity, it would accept a step change under limited circumstances.[17] The AER goes on to state that it would consider whether the costs associated with such a step change are unavoidable and material such that the base operating expenditure, trended forward by the forecast rate of change, would be insufficient for the distributor to recover its efficient and prudent costs.[18] For example, the AER draft determinations accepted AusNet Services proposed I step change for 'innovation expenditure' and Jemena's proposed insurance premiums step change.

3.2.2 AER's approach to assessing step changes does not comply with the Law and Rules

The AER errs in seeking to apply its analytical framework for assessing step changes.

We do not consider that all relevant considerations are captured by the framework. In considering guiding principles to assist in determining whether step changes are likely to reflect the operating expenditure criteria, the Australian Competition Tribunal (**Tribunal**) has held that:[19]

- if a step change is to reasonably reflect the operating expenditure criteria, a cost saving arising from efficiencies within a distributor's business attributable to the planned capital expenditure and operating expenditure should be reflected in the forecast operating expenditure
- alternatively, if a cost saving is not expected, a step change should result in a benefit to customers that warrant the forecast operating expenditure
- identifying the expected benefit and giving a value to it is relevant to evaluating whether the expenditure is 'efficient' and 'prudent'
- alternatively, if neither a cost saving nor a customer benefit is expected, the step change should be the consequence of an unavoidable change in activity due to an external obligation.

Notably, these principles (initially proposed by the AER in the proceeding) are markedly wider than those referred to by the AER in its Expenditure Forecast Assessment Guideline and refined in subsequent decisions.

In any event, any such an analytical framework cannot detract from the primacy of the Rules. The overarching principle must always be that where step changes form part of an operating expenditure forecast that otherwise

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15 AER, Better regulation: Expenditure forecast assessment guideline, November 2013, p. 11.

16 at 7-95 to 7-97.

17 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 19.

18 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 19.

19 *Application by EnergyAustralia and Others* [2009] ACompT 8, [194].

reflects each of the operating expenditure criteria, those step changes must be accepted by the AER.[20] Overreliance on any 'step change criteria', without proper regard to the Rules, risks affecting the integrity of the AER's decision, as has been recognised by the Tribunal.[21]

The AER's assessment of materiality of step changes

A particular issue that arises in the draft determination is the rejection of step changes that do not arise from a change in regulatory obligations or an efficient capex/opex trade-off on the basis that the expenditure is not 'material'. The AER's approach has no basis in the Law or Rules.

First, there is no express materiality threshold under the Rules for the purposes of assessing whether operating expenditure should be included in the forecast. This can be contrasted, for example, with the cost pass through provisions, which require a pass through event to give rise to 'materially' higher or lower costs to the distributor in providing direct control services than it would have incurred but for the event, with 'materially' being defined as the change in costs being more than one per cent of the annual revenue requirement for a regulatory year.[22] The application of a materiality threshold in the pass through context is warranted given the adjustments made to operating expenditure are occurring *after* the distribution determination is made and a materiality threshold promotes the stability and predictability of the regime for the regulator and the service provider.[23] Similarly, the AER may revoke and substitute a determination during a regulatory period in the event of a 'material' error or deficiency of a specified kind.[24] Again, correction of errors occurs *after* the making of the distribution determination and a materiality threshold is important in this context in order to increase the certainty and transparency associated with the regulatory framework, and to maintain the incentives built into that framework.

Secondly, there is no basis in the Rules for applying a materiality threshold to operating expenditure step changes in circumstances where:

- we are an efficient distributor, and thus the base year operating expenditure can be assumed to reflect the prudent and efficient costs of meeting the operating expenditure criteria, having regard to the operating expenditure factors
- the AER is proposing to assume productivity growth of 0.5 per cent, which has the effect of reducing real expenditure allowances in the next regulatory period (for example, the AER reduced total operating expenditure by $17.1 million ($2020/21) by way of a productivity adjustment)[25]
- the AER is proposing to apply real non-labour price growth of zero (i.e. non-labour price growth equal to CPI)
- the enduring impact of COVID-19 will result in higher costs for our operations due to changed work practices beyond the next few years and will be difficult to unwind in future as expectations regarding social distancing have changed

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20 Rules, clause 6.5.6(c).

21 Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1, [366]-[373] (affirmed on review: *Australian Energy Regulator v Australian Competition Tribunal (No 2)* [2017] FCAFC 79; *Australian Energy Regulator v Australian Competition Tribunal (No 3)* [2017] FCAFC 79).

22 Rules, clause 6.6.1; Chapter 10 definitions of 'positive change event', 'negative change event' and 'materially'.

23 See, for example: Australian Energy Market Commission (**AEMC**), National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, 29 November 2012, pp. 204-205.

24 Rules, clause 6.13(a).

25 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 44.

- we are already being required by the draft determination to absorb a number of step changes, in addition to further step changes we chose not to include in our original proposal, to maintain affordability for our customers in what are challenging times.

The Rules require the AER to accept forecast operating expenditure where it reasonably reflects the prudent and efficient costs of achieving the operating expenditure objectives, and a realistic expectation of the demand forecast and cost inputs. Given the above pressures on operating expenditure that we will face in the next regulatory period, it is inconsistent with the requirements of the Rules and revenue and pricing principles to apply a 'materiality' threshold before making adjustments to the base year operating expenditure when determining total forecast operating expenditure in a distribution determination.

In addition, the AER makes a further fundamental error in rejecting a number of step changes on the basis they are, individually, not 'material'. This is not consistent with the requirements of the Rules or Law. As recognised by the AER, the assessment the AER is required to make is as to total operating expenditure and not the individual forecast expenditure components.[26] This means that it is the cumulative impact of expected changes on future total expenditure that is the relevant consideration. The AER recognises that the cumulative impact of changes is the relevant consideration when assessing materiality in the context of adjusting our capital expenditure sharing scheme reward payment, concluding that the impact of deferred expenditure on transformer replacement satisfies the materiality threshold because other expenditure considered has already met the threshold. The AER states:[27]

> *As we are satisfied that the inclusion of the deferred poles repex into Powercor's approved total capex allowance is materially higher than had the poles repex not been deferred, it follows that the addition of $8.9 million in deferred transformers repex into the approved total capex allowance satisfied the materiality threshold.*

Taken to an extreme, the AER's approach of considering the materiality of proposed step changes individually would mean a distributor's expenditure could be expected to double on the basis of step changes that are, on their own, not 'material' but which cumulatively have a significant impact such that a failure to include those step changes in the operating expenditure forecast would deprive the distributor of the opportunity to recover their prudent and efficient costs.

The AER appears to consider that a 'materiality' requirement is justified on the basis that it is necessary to avoid a potential upward bias in total operating expenditure given there is an incentive for distributors to identify increasing new and costs but not the same incentive to identify decreasing costs.[28] The AER stated elsewhere in the draft determination that:[29]

> *If we were to include step changes for immaterial costs in our alternative estimate, then arguably we should also include negative step changes for decreases in immaterial costs. In this regard, we note that over the next regulatory control period a possible negative step change could arise due to the relaxing of some obligations required by ESV in their electric line clearance regulations, which may lead to immaterial reductions in costs. Powercor has not proposed this as a negative step change. We consider step changes are not meant to be bottom up assessments of all cost categories, and that immaterial increases or decreases should be managed by businesses.*

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[26] AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 14.

[27] AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 9: Capital expenditure sharing scheme, September 2020, p. 12.

[28] AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 20.

[29] AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 62.

We do not agree that there is upward bias in the total operating expenditure in our revised proposal. We have assessed our expenditure and changes in obligations for potential negative step changes in preparing our revised proposal and have not identified any. This is not surprising as in our experience, the cost burden from obligations and regulations under which we operate only tends to increase, not decrease. With regard to the electric line clearance regulations, the author of the regulatory impact statement from which the AER draws support, Deloitte, accepted that there is 'some subjectivity' in relation to its impact assessment, expressly citing the potential impacts on distributors' clearance activities from the changes, which could impact the assessment of the difference between the prior and current line clearance regulations. Contrary to the AER's suggestion, the new regulations are not expected to decrease our costs of electric line clearance.

We raise our specific concerns with the AER's assessment of the step changes dealt with this in business case below.

3.2.3 Solar enablement

The draft determination regarding our solar enablement step change fails to recognise that our solar enablement program represents an efficient capex/opex trade-off. The AER also errs in its conclusion that our tapping expenditure is immaterial and captured by the rate of change.

We also do not accept that the AER's alternative tapping unit rates or the AER's assessment that the costs of our monitoring and compliance program to ensure compliant inverter settings are not justified. Neither result in an operating expenditure forecast that reasonably reflects the operating expenditure criteria.

Each of these matters are discussed further below.

AER fails to recognise our efficient capex/opex trade-off

The AER's draft determination fails to recognise that our proposed solar enablement program represents an efficient capex-opex trade-off. This is a fundamental flaw in the draft determination.

As our step change provides benefits to customers as the most efficient solution to enable growing solar penetration on our networks, effectively deferring network augmentation, we must be afforded the opportunity to recover at least our efficient costs of enabling residential rooftop solar.

Our proposal to undertake tapping activities and monitoring and compliance program to rectify non-compliant inverter settings are low cost alternatives to incurring capital expenditure for network solutions managing distributed energy resources. This was recognised by the consultant engaged by the AER to consider our proposal, EMCa, and was a basis on which EMCa concluded that less LV augmentation capital expenditure is justified. EMCa states:[30]

> *Given that Powercor's strategy involves LV augmentation only after seeking to address issues through customer installation compliance, use of its DVMS and tapping, with a realistic technical/economic appraisal for each relevant LV network over the course of the next regulatory period, we consider that Powercor will find that considerably less LV augmentation expenditure is justified.*

Our tapping activities and monitoring and compliance program for addressing non-compliant inverter settings is thus recognised as reducing our likely capital expenditure, but the costs associated these activities are not funded through an operating expenditure step change.

Tapping

The draft determination concludes that our proposal to undertake tapping activities and the volume of tapping we proposed was prudent and reasonable. However, as noted in section 2.3.1 above, the AER substituted our

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30 EMCa, Powercor - Review of aspects of proposed expenditure, Report prepared for: Australian Energy Regulator, August 2020, p. 140.

proposed unit rate of $1,959 ($2020/21) with an EMCa benchmark figure of either $865 or $1,000, which reduced the overall value of the step change. The AER then determined that the reduced rate was 'immaterial' and should be managed within our forecast base operating expenditure and rate of change.[31]

For the reasons outlined below, we do not accept that the AER's alternative unit rates produce forecasts that reasonably reflect the operating expenditure criteria. Further, for the reasons outlined in section 3.2.2 above, we do not consider the AER's analytical framework for rejecting our proposed solar enablement step change on the basis our tapping costs are not material complies with the Law and Rules and maintain that this does not provide a basis on which to reject our proposed solar enablement step change. Finally, we do not agree that our proposed solar enablement expenditure (including tapping) is captured by the rate of change.

Unit rate efficiency

The unit rate used in our original proposal was based on actual past tapping costs which reflect the efficient cost of tapping relative to our networks. However, to address AER's concerns, we have updated our step change to reduce the unit rate to United Energy's unit rate for the same service.

United Energy's unit rate represents a market-tested competitive rate that was agreed following a rigorous tender process. As such, United Energy's unit rate is the most appropriate evidence of efficient costs. Using these costs is in line with the Tribunal previous confirmation that evidence of the outcome of a competitive process can demonstrate an efficient price.[32]

We do not consider it appropriate to substitute our unit rate with an AusNet Services rate. The AER does not appear to have made any attempt to ensure AusNet’s and our unit rates (or United Energy's) reflect the same services. Our review suggests that the two rates do not compare like-for-like services, for example, at a minimum, we are aware that United Energy's rate includes the cost of managing related planned outages, whereas AusNet’s does not. In addition, United Energy's unit rate (and, we imagine, AusNet's) is one cost in a schedule of many; it is not appropriate to view this unit cost in isolation, without considering the competitiveness of the tender overall. To the extent that the AER seeks to rely on an AusNet Services rate in the final determination, we request that the AER make the sufficient details of the AusNet Services unit rates available and provide us with an opportunity to comment to ensure we are informed of material issues under consideration by the AER and given a reasonable opportunity to make submissions in respect of the determinations before they are made, consistent with the requirements of section 16(1)(b) of the Law and administrative law obligations to afford natural justice and good regulatory practice.

Our view is that United Energy's unit cost of $1,535 is efficient and produces forecasts that reasonable reflect the operating expenditure criteria in all the circumstances and we have substituted our original unit cost of $1,959 with $1,535 in our revised regulatory proposal.

AER errs in applying a 'materiality' threshold

The AER's approach in the draft determination of rejecting our proposed solar enablement step change on the basis that the proposed expenditure is 'immaterial' is deeply flawed.

We disagree with the AER's framework for assessing step changes for the reasons outlined in section 3.2.2 above.

Even on the AER's approach, however, there is no basis for applying a materiality threshold to our solar enablement step change. As discussed above, our proposed solar enablement step change represents a prudent

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31 AER, Draft Decision Powercor, Distribution Determination 2021 - 2026, Attachment 6: Operating expenditure, September 2020, p. 53.

32 *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* [2016] ACompT 1, [372] (affirmed on review: *Australian Energy Regulator v Australian Competition Tribunal (No 2)* [2017] FCAFC 79; *Australian Energy Regulator v Australian Competition Tribunal (No 3)* [2017] FCAFC 79).

and efficient capex/opex trade-off. In these circumstances, the AER general approach is not to go on to consider whether the costs associated with the step change are 'material', which approach we consider is consistent with the significance of efficient capex/opex trade-off and avoiding the perverse incentives to incur inefficient capital expenditure that would otherwise arise.[33] Even applying its own analytical framework, therefore, the AER has erred in applying a 'materiality' threshold.

Solar enablement expenditure is not captured by the rate of change

The AER states that its standard approach is not to provide a step change to manage activities in a changed operating environment as increases in operating expenditure in line with output growth would typically provide adequate compensation.[34] However, the AER accepts that in the short term the output growth forecast may not fully account for distributed energy resources.[35] In its 2020–2025 final determination for SA Power Networks, the AER accepted a step change for LV Management Future Networks as:[36]

> *there is a likelihood that the output growth forecast may not fully compensate for the higher opex to address distributed energy resource management.*

The AER forecast output growth in the draft determination by:[37]

- calculating growth rates for four outputs: customer numbers; circuit line length; energy throughput; and ratcheted maximum demand
- calculating five weighted average overall output growth rates using the output weights from five models
- averaging the five model specific weighted overall output growth rates.

Significantly, growth in distributed energy resources, which increases the number of constraints to our network solar PV 'hosting capacity', which in turn increases the number of PV inverters tripping and thus drives our solar enablement expenditure, is not a direct input into the forecasting of output growth and is not adequately reflected in any of the outputs considered when forecasting output growth. Further, the growth in distributed energy resources negatively impacts the rate of change as energy consumption and peak demand decline with growth in distributed energy resources.

The AER's own consultant engaged to consider the rate of change agreed that the factors the AER considers in determining output growth fail to adequately capture the increasing growth in distributed energy resources. Economic Insights states:[38]

> *We concur that the growth in DER is likely to be having a significant effect on DNSPs and could be increasing their opex as DNSPs strive to maintain network stability and capex in the face of many new small and unpredictable energy suppliers appearing on their networks. To adequately address this emerging situation we need to consider expanding the outputs included in our economic benchmarking models to include a DER output. That is, a DER output could be creating something of an omitted variable issue as the specification now stands.*

Economic Insights went on to suggest that this should be part of a wider periodic review of economic benchmarking rather than a part of a distribution determination process. However, Economic Insights indicates

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33 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 19.

34 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 52

35 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 52.

36 AER, Final Decision SA Power Networks, Distribution Determination 2020-2025, Attachment 6: Operating expenditure, June 2020, p. 23

37 AER, Draft Decision Powercor, Distribution Determination 2021-2026, Attachment 6: Operating expenditure, September 2020, p. 38

38 Economic Insights, Review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights, 18 May 2020, p. 17.

that, in the meantime, where distributed energy resources are increasing operating expenditure requirements, this would be best handled in the short-term via a step change.[39]

In these circumstances, there is no basis for concluding that the output growth can be expected to allow us to recover our prudent and efficient costs of enabling customers to export excess solar back into the network.

Monitoring and compliance program

The success of our solar enablement program relies on new inverter settings being applied. We have modelled voltage rise based on 100 per cent compliance of new solar systems. If installers fail to apply these settings, voltage rises will be significantly higher than forecast and we will experience quality of supply and system security issues. In addition, customers will continue to experience more constraints. As such, our original proposal included a monitoring and compliance program.

Whilst EMCa considered that addressing non-compliance of inverter settings was likely to be a relatively cost-effective means of limiting PV export voltage rise, the draft determination concluded that we had not sufficiently justified the cost of our proposed monitoring and compliance program, demonstrated that other more cost-effective options had been considered, or established that the program was required in addition to our power quality program.

Identifying and rectifying compliance is not an easy task. In contrast to the AER's conclusion, to date we have:

- updated our model standing offers to require these settings to be applied
- partnered with the Clean Energy Council to hold training with accredited solar installers to educate them on the need to apply the new standards
- required solar installers to attest that the power quality settings have been applied after completing installation
- worked with the Department of Environment Land Water and Planning to determine how best to achieve compliance, including requesting that they check for compliance as part of their Solar Homes audit, however this has not been deemed practicable.

Yet, even after undertaking all the above precautions, around 60-70 per cent of new solar installations are non-compliant. Often customers are not aware of their non-compliance because it is due to their installer not following procedures. Our monitoring and compliance program includes costs to implement remote monitoring using our existing information management systems, based on current rates of non-compliance, assuming it takes one hour on average to rectify the non-compliance. This is a conservative estimate given we expect non-compliance with the new inverter settings to be much higher based on the experience of other distributors and our experience to date.

In querying why we do not simply extend our power quality program, the AER and EMCa have misunderstood the nature of this program (notably, neither the AER nor EMCa requested any further information on the program). The power quality program differs materially from the monitoring and compliance program in question. Power quality comprises network planners who plan and schedule works to fix voltage issues. As already described, the compliance and monitoring program we are proposing relies on running data analytics over advanced metering infrastructure data to find non-compliant sites, and a customer services team addressing and rectifying (by working with the customer i.e. not via voltage works) the identified non-compliance. The two programs do not share any complementarities and require vastly different skill sets. There

[39] Economic Insights, Review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights, 18 May 2020, p. 17.

would be no efficiencies found in expanding power quality to incorporate the proposed monitoring and compliance program.

The only other option to address non-compliance (leaving aside the steps we have already taken, and the proposed monitoring and compliance program) is augmentation of the network. This would be significantly more costly. As such, our monitoring and compliance program is an efficient capex/opex trade-off and should be accepted in our final regulatory determination.

3.2.4 REFCL on-going costs

In the draft determination the AER accepted our REFCL on-going step change, however applied a different methodology to calculating the base operating expenditure, resulting in a material decrease in allowed expenditure.

We do not agree with the AER's approach to calculating the base operating expenditure of the step change. We consider that the step change should be equal to the forecast required operating expenditure less any operating expenditure already included in the 2021-2026 operating expenditure base.

We have aligned our calculation with this methodology used for the total operating expenditure forecast and calculated the step change as:

- required operating expenditure in 2021–2026
- less difference between 2019 approved REFCL allowance and 2020 approved REFCL allowance
- less 2019 actual.

3.3 Revised proposal forecasts

Table 3 below shows the forecast value of our solar enablement and REFCL on-going costs step changes.

Table 3 Summary of reproposed step change, $ million 2021

Step change	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Solar enablement	1.1	1.0	1.2	0.7	0.7	4.8
REFCL on-going costs	0.3	0.4	0.9	1.0	1.0	3.7

Source: Powercor