DRAFT DECISION

SA Power Networks Distribution Determination 2020 to 2025

Attachment 5 Capital expenditure

October 2019

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to SA Power Networks for the 2020–2025 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme

Attachment 12 – Classification of services

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Attachment 14 – Pass through events

Attachment 15 – Alternative control services

Attachment 16 – Negotiated services framework and criteria

Attachment 17 – Connection policy

Attachment 18 – Tariff structure statement

Contents

Shortened forms

Shortened form	Extended form
ACS	alternative control services
ADMS/OMS	advanced distribution management system/outage management system
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
A&W	asset and works
capex	capital expenditure
CBRM	condition based risk management
CCP14	Consumer Challenge Panel, sub-panel 14
CESS	capital expenditure sharing scheme
CPI	Consumer Price Index
DER	distributed energy resources
DSO	distribution system operator
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
ESCoSA	Essential Service Commission of South Australia
EMCa	Energy Markets Consultants associates
EWP	elevated work platform
F&A	framework and approach
ICT	information and communications technology
LV	low voltage
MW	megawatt
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER or the rules	national electricity rules
NSP	network service provider
opex	operating expenditure
PV	photovoltaic
repex	replacement expenditure

Shortened form	Extended form
RAB	regulatory asset base
RIN	regulatory information notice
RPP	revenue and pricing principles
SACOSS	South Australian Council of Social Service
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	supervisory control and data acquisition
SCS	standard control services
STPIS	service target performance incentive scheme
UFLS	under frequency load shedding
WACC	weighted average cost of capital
WSE	work selection effectiveness

5 Capital expenditure

Capital expenditure (capex) refers to the money required to build, maintain or improve the physical assets needed to provide standard control services. Generally, these assets have long lives and the distributor will recover capex from customers over several regulatory periods. A distributor's capex allowance contributes to the return of capital and return on capital building blocks that form part of its total revenue requirement.

Under the regulatory framework, a distributor must include a total forecast capex that it considers is required to meet or manage expected demand, comply with all applicable regulations, and to maintain the safety, reliability, quality, security of its network (the capex objectives).[1]

We must decide whether or not we are satisfied that this forecast reasonably reflects prudent and efficient costs and a realistic expectation of future demand and cost inputs (the capex criteria).[2] We must make our decision in a manner that will, or is likely to, deliver efficient outcomes that benefit consumers in the long term (the National Electricity Objective).[3]

The *AER capital expenditure assessment outline* explains the obligations of the AER and distributors under the NEL and NER in more detail.[4] It also describes the techniques we use to assess a distributor's capex proposal against the capex criteria and objectives. The outline is part of the supporting information for this draft decision. This attachment sets out our draft decision on SA Power Networks' total capex. The following appendices provide our detailed analysis:

- Appendix A - Capex driver assessment
- Appendix B - Engagement and information gathering process
- Appendix C - Repex modelling considerations
- Appendix D - Forecast demand
- Appendix E - Ex post statement of efficiency and prudency
- Appendix F - Contingent project.

We have based our draft decision on our analysis of the information we have to-date. We will be informed by SA Power Networks' revised proposal, submissions and further analysis in arriving at our final decision in April 2020. In this attachment, we use real $2019–20 million end of year unless otherwise noted.

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1 NER, cl. 6.5.7(a).

2 NER, cl. 6.5.7(c).

3 NEL, ss. 7, 16(1)(a).

4 AER, *Draft decision - SA Power Networks distribution determination 2020–25 - AER capital expenditure assessment outline*, October 2019.

5.1 Draft decision

We do not accept SA Power Networks' forecast capex, as SA Power Networks has not satisfied us that its total net capex forecast of $1719.7 million reasonably reflects the capex criteria. Our substitute estimate of $1246.9 million is 27.5 per cent below SA Power Networks' forecast and is 25 per cent below estimated expenditure over the 2015–20 regulatory control period. Table 5.1 outlines out draft decision. We are satisfied that our substitute estimate reasonably reflects the capex criteria and it will allow SA Power Networks to maintain the safety, service quality and reliability of its network, consistent with its legislative obligations.

Table 5.1 Draft decision on SA Power Networks' total net capex forecast ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
SA Power Networks' proposal	357.4	369.9	334.2	332.3	325.8	1,719.7
Draft decision	264.8	270.8	247.6	237.2	226.5	1,246.9
Difference	-92.6	-99.1	-86.6	-95.2	-99.3	-472.8
Percentage difference (%)	-25.9	-26.8	-25.9	-28.6	-30.5	-27.5

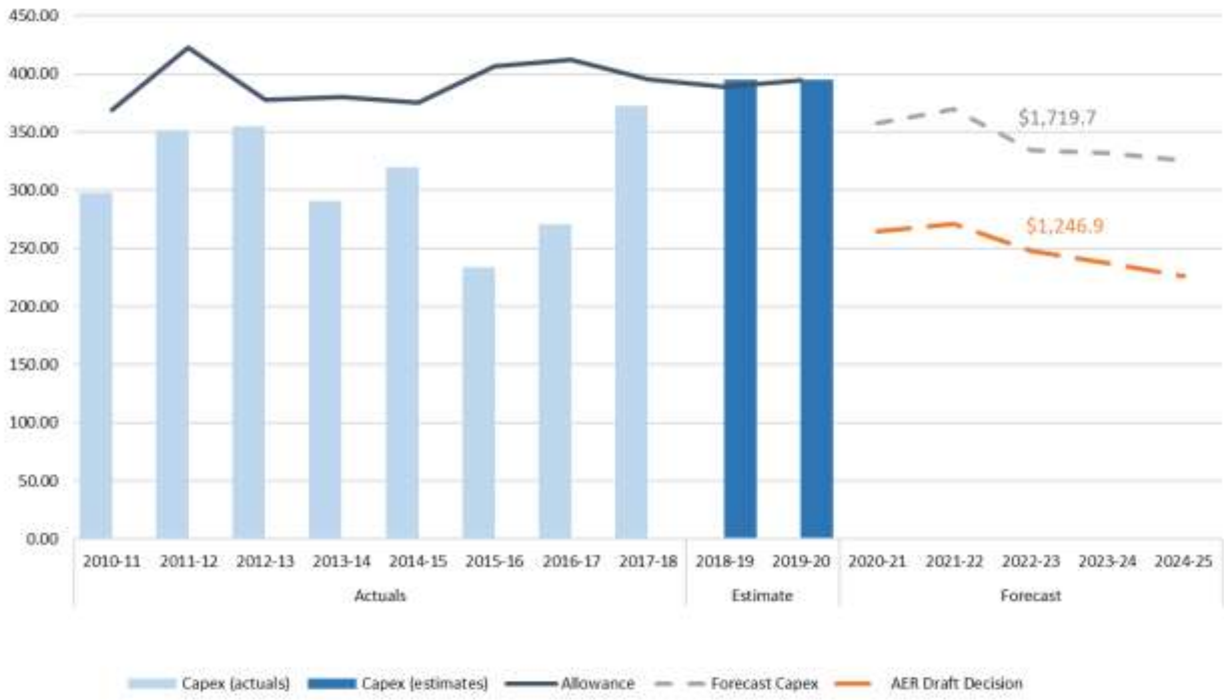
Source: AER analysis.

Notes: Numbers may not sum due to rounding. The figures above do not include equity raising costs, capital contributions and asset disposals. See attachment 3 for our assessment of equity raising costs.

5.2 SA Power Networks' proposal

SA Power Networks' proposed total forecast of net capex of $1719.7 million over the 2020–25 period, is $245.1 million (16.6 per cent) higher than its actual net capex of $1488.1 million over the 2013–18 regulatory years. Forecast capex is approximately four per cent higher than what SA Power Networks expects to spend over the 2015–20 regulatory control period. Figure 5.1 outlines SA Power Networks' historical capex performance against its 2020–25 capex forecast.

Figure 5.1 SA Power Networks' historical vs forecast capex snapshot ($ million, 2019–20)

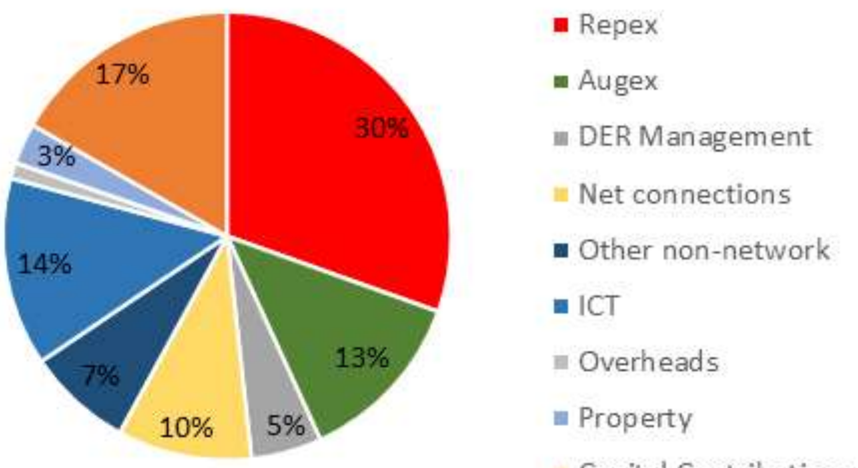


Source: AER analysis.

Note: SA Power Networks' actual and estimated capex is based on SA Power Networks' recast category analysis RIN data.

The key drivers of SA Power Networks' capex proposal are represented in Figure 5.2 below.

Figure 5.2 Key drivers of SA Power Networks' gross capex



Source: AER analysis.

5.3 Reasons for draft decision

SA Power Networks has not satisfied us that its forecast reasonably reflects the capex criteria. We applied the assessment approach set out in the *AER capital expenditure assessment outline* - a supporting document to this decision.[5] Appendix A sets out how we applied our assessment techniques and how we came to our position.

Based on the information before us and weighing up a number of factors, SA Power Networks has not provided sufficient evidence to satisfy us of the prudency and efficiency of its forecast capex. Energy Market Consulting associates (EMCa), who were engaged to assist us in our review, also came to the same conclusion on when reviewing several capex categories (e.g. aspects of repex, augex, connections and ICT).

A number of reasons have led us to this draft decision. In particular:

- SA Power Networks has overstated its network risk or benefit in analysis to support its forecast. We observed inflated risk assumptions to derive forecast repex. Similarly, for its information and communications technology (ICT) capex, SA Power Networks has overstated the forecast benefits expected from some of its non-recurrent ICT capex.
- For some non-recurrent projects and programs, SA Power Networks has not provided sufficient detail and information to support its proposal and we have not included an allowance for these. We encourage SA Power Networks to address the issues we have identified in its revised proposal.
- Some programs are not required, or more likely can be deferred. Further, a lack of rigour in the testing of reasonableness of the forecast, which contrasts with the more comprehensive detailed options analysis undertaken in the annual budgeting process once the capex allowance is confirmed.
- While we have accepted SA Power Networks' forecast capex of $30.3 million for LV management, which we refer to as the Distribution System Operator (DSO) transition program, we have observed that there is lack of a top-down challenge which would identify the interrelationships that exist between programs and projects. This is evident in SA Power Networks' augmentation expenditure (augex) proposal where its proposed capex for LV monitoring, voltage regulation and quality of supply appear ad-hoc, particularly the interrelationship with the DSO transition project.
- Inconsistency in SA Power Networks’ program level build-up with its asset management plans or its reset regulatory information notice (RIN), especially in forecast repex, connections capex and augex. This inconsistency further reduces our confidence in SA Power Networks' proposed forecast capex.

[5] AER, *Draft decision - SA Power Networks distribution determination 2020–25 - AER capital expenditure assessment outline*, October 2019.

Based on the information that is available to us we have developed a substitute forecast that, in our view, represents prudent and efficient expenditure and meets the capex criteria. However, we will carefully consider any additional information that SA Power Networks or other stakeholders provide us in making our final decision.

We have engaged extensively with SA Power Networks on the evidence required to demonstrate the prudency and efficiency of its proposed expenditure and the reasons for our draft decision. Our engagement with SA Power Networks has been constructive, with ongoing dialogue throughout the review process. However, not all the information required to assess SA Power Networks expenditure has been provided. We have therefore developed a substitute estimate on the basis of the information that is available to us. Table 5.2 sets out the capex amounts by driver that we have included in our substitute estimate and how it compares to SA Power Networks' initial proposal.

Table 5.2 Capex driver assessment for 2020–25 ($2019–20, million)

Category	Initial proposal	AER draft decision	Difference ($)	Difference (per cent)
Repex	637.2	508.5	-128.6	-20.2
DER Management capex	106.6	74.7	-32.0	-30.0
Augex	265.4	187.3	-78.1	-29.4
Gross Connections	553.0	513.6	-39.4	-7.1
ICT	284.6	196.8	-87.7	-30.8
Fleet	116.6	79.9	-36.7	-31.5
Property	61.5	-	-61.5	-100.0
Other non-network	42.2	30.2	-11.9	-28.3
Capitalised overheads	62.4	56.0	-6.4	-10.3
Superannuation adjustment	-38.3	-37.4	-1.0	-2.5
Gross Capex	**2091.1**	**1609.6**	**-481.5**	**-23.0**
Less capital contributions	350.1	347.1	-3.0	-0.9
Less disposals	21.4	15.7	-5.7	-26.8
Net Capex	**1719.7**	**1246.9**	**-472.8**	**-27.5**

Source: AER analysis.

Notes: Numbers may not add due to rounding. Table excludes equity raising costs. The draft decision position includes modelling adjustments relate to SA Power Networks' Consumer Price Index (CPI) and real price escalation assumptions.

Table 5.3 summarises our findings and the reasons for our draft decision by capex driver. This reflects the way we have assessed SA Power Networks' total capex forecast. However, we use our findings on the different capex drivers to assess a distributor's proposal as a whole and arrive at a substitute estimate for total capex where necessary.

Our assessment highlighted that most of the capex drivers associated with SA Power Networks' proposal, such as augmentation, replacement and non-network expenditure, are likely to be higher than an efficient level and therefore are not likely to reasonably reflect the capex criteria,[6] taking into account the capex factors and the revenue and pricing principles.[7]

We therefore formed a substitute estimate of total capex. We test this total estimate of capex against the capex criteria (see appendix A for a detailed discussion). We are satisfied that our substitute estimate represents a total capex forecast that reasonably reflects the capex criteria and it forms part of an overall distribution determination that is likely to contribute to the achievement of the National Electricity Objective to the greatest degree.

Table 5.3 Summary of our findings and reasons

Issue	Reasons and findings
Governance and forecasting methodology	SA Power Networks' governance and management framework led to an overstated total capex forecast. Many of SA Power Networks' programs either were not supported with a cost-benefit analysis, or if they did, the risk or the benefit were overstated. In addition, we have identified a clear disconnect between SA Power Networks' annual budgeting process and its ex-ante forecast. We discuss this in more detail in section A.1.1 below.
DER Management Expenditure[8]	We have accepted SA Power Networks' DSO transition program. However, our review has identified that SA Power Networks did not identify and incorporate the interrelationships that may exist between its distributed energy resources (DER) management programs, particularly the DSO transition, LV monitoring and Quality of Supply programs. For its voltage regulation program, SA Power Networks did not demonstrate that its preferred option is the most efficient. We discuss our detailed analysis in section A.2 of this draft decision.

6 NER, cl. 6.5.7(c).

7 NEL, cl. 7A, 16(2).

8 Distributed Energy Resources (DER) commonly refers to solar PV, storage, electric vehicles, and other consumer appliances that are capable of responding to demand or pricing signals. Increasing DER penetration represents a change in the way that consumers interact with electricity networks and the demands that it places on networks. DER management expenditure is the expenditure which seeks to manage the growing effects of higher penetration of DER on the network, in particular the effects of solar PV and the impact on distributor's ability to control voltage.

Issue	Reasons and findings
Augex	We have accepted some categories of augex, such as power line environmental committee,[9] the bushfire mitigation program and environmental-related capex. Our bottom-up review of the remaining augex categories has identified that SA Power Networks' forecast either lacks robust option analysis, overstates the benefits or does not establish the need to undertake a project (such as a regulatory obligation). We discuss our detailed analysis and reasoning in section A.3 of this draft decision.
Customer connections capex	We have accepted SA Power Networks' capital contributions, which is consistent with current period levels. However, we did not accept SA Power Networks' forecast net connections capex. Our review has identified that SA Power Networks' economic modelling includes unsupported assumptions. In addition, EMCa has identified material discrepancies between SA Power Networks' reset RIN and the supporting economic modelling. SA Power Networks provided a reconciliation, which is included a 'Reg adjustment' of $47 million, which is unjustified.
Repex	Our substitute estimate for repex is 11 per cent higher than SA Power Networks' actual expenditure over the 2013–18 regulatory years and 20 per cent lower than its forecast. Our review has identified that some of SA Power Networks' repex lacks cost benefit analysis and SA Power Networks' condition-based modelling overstates risk and therefore forecast repex required to mitigate this risk. Where SA Power Networks has applied historical trend as the basis for its forecast, it included estimates for the last two years of 2015–20, which are significantly higher than its actuals over the 2013–18 regulatory years. SA Power Networks has not provided sufficient evidence to demonstrate that this step up over the current period is likely to occur or to continue into the forecast period. We discuss our detailed analysis and reasoning in section A.5 of this draft decision.
ICT capex	We have accepted SA Power Networks' recurrent ICT capex, which is consistent with its historical expenditure. However, we have not accepted four of eight of SA Power Networks' proposed non-recurrent ICT projects, as it has either not established the need, has not considered all potential options or has overstated the expected benefits. These programs are the Assets and Works, the SAP S4 upgrade, Worker Safety fatigue and the Ring-fencing IT compliance program. We discuss our analysis in section A.6 of this draft decision.

[9] Expenditure to underground parts of the network in accordance with State Government legislation.

Issue	Reasons and findings
Fleet capex	Our analysis has identified that SA Power Networks is currently among the most costly providers for fleet on a per employee basis. We have assessed SA Power Networks' bottom-up build for fleet and identified that the service life and unit rate assumptions provided exceed efficient costs. In addition, we have identified a discrepancy in the allocation of fleet from the bottom-up build to SCS and ACS. Our substitute estimated applied an allocation that is consistent with the reset RIN. We discuss our analysis in section A.7 of this draft decision.
Property capex	We have not included any property-related capex as part of our substitute estimate, as SA Power Networks has not provided evidence that is sufficient to support any component of the buildings and property capex forecast. SA Power Networks has agreed to provide new information to supports its proposed expenditure as part of its revised proposal. We will have regard to this information in making our final decision. We discuss our analysis in Section A.8 of this draft decision.
Other non-network capex	Other non-network capex includes plant, tools and equipment. The difference between our substitute estimate and SA Power Networks' proposal relates to the Advanced Distribution Management System/Outage Management System (ADMS/OMS) upgrade project. SA Power Networks has not established the need to undertake the upgrade, or provide any options analysis and cost-benefit assessment to support the proposed investment. We discuss our analysis in Section A.9 of this draft decision.
Capitalised overheads	We have made consequential adjustments to overheads to reflect the lower support requirements of direct capex for our substitute estimate. We accept SA Power Networks' proposed negative superannuation adjustment which has been attributed to its capitalised corporate overheads. We note this is not an overhead but rather an accounting adjustment. We discuss our analysis in Section A.10 of this draft decision.
Asset disposals	SA Power Networks' asset disposals are solely composed of fleet disposals. We have made commensurate adjustments to asset disposals to reflect our draft decision on fleet capex, such that the volumes of the fleet disposals is equal to the volume of fleet replacements.
Modelling adjustments	In our draft decision, we have made modelling adjustments to reflect actual CPI rather than estimates CPI for 2018–19 year. We have also made adjustments to SA Power Networks' real cost escalations. The modelling adjustments result in a reduction of 33.7 million or 2 per cent from SA Power Networks' initial capex forecast. We discuss this further in Section A.1.2 of this draft decision.

Issue	Reasons and findings
Contingent project	SA Power Networks has not demonstrated that its electricity system security project of $79.8 million is reasonably required to achieve the capex objectives.[10] SA Power Networks may have had limited information when it submitted its regulatory proposal. However, we have not received sufficient information to-date, which supports the contingent project. While we acknowledge that SA Power Networks considers this contingent project capex is required to respond to a regulatory obligation, there is no indication of what the requirements of this regulatory obligation are. Further, costs to comply with regulatory obligations can be included as a pass through. Our analysis of the contingent project is discussed in Appendix F.

10 The proposed project is to implement changes to the existing under frequency load shedding (UFLS) scheme and/or implement additional measures as required by AEMO to maintain security of supply within South Australia.

A Capex driver assessment

This appendix sets out our findings and views by capex category. In each of these sections, we explain our assessment of the amount of capex that we have included in our total substitute estimate that reasonably reflects the capex criteria.

We used various qualitative and quantitative assessment techniques to assess the different elements of SA Power Networks' proposal to determine whether its proposal reasonably reflects the capex criteria.

More broadly, we also take into account the revenue and pricing principles set out in the NEL.[11] In particular, we take into account whether our overall capex forecast will provide SA Power Networks with a reasonable opportunity to recover at least the efficient costs it incurs to:

- provide direct control network services
- comply with its regulatory obligations and requirements.[12]

When assessing capex forecasts, we also consider:

- that the prudency and efficiency criteria in the NER are complementary and reflect the lowest long-term cost to consumers to achieve the expenditure objectives[13]
- past expenditure was sufficient for the distributor to manage and operate its network in previous periods, to the extent that it achieved the capex objectives[14]
- the capex required to provide for a prudent and efficient distributor's circumstances to maintain performance at the targets set out in the service target performance incentive scheme (STPIS)[15]
- the annual benchmarking report, which include measures of total cost efficiency and overall capex efficiency, including consideration to a distributors' inputs, outputs and its operating environment
- the various interrelationships between the total capex forecast and other constituent components of the determination, such as forecast opex and STPIS interactions.[16]

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11 NEL, ss. 7A and 16(2).

12 NEL, s. 7A.

13 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 8–9.

14 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 9.

15 The STPIS provides incentives for distributors to further improve the reliability of supply only where customers are willing to pay for these improvements.

16 NEL, s. 16(1)(c).

A.1 Total capex consideration

Our substitute estimate of SA Power Networks' total capex forecast for the 2020–25 regulatory control period is $1246.9 million. We have relied on the various assessment techniques described in *AER capital expenditure assessment outline*, which accompanies this decision.[17] In reaching this decision, we have considered all the information before us, including submissions from Business SA, the CCP14, the Centre for Energy and Environmental Markets, the Clean Energy Council, the CSIRO, Dr Penelope Crossley, EnergyAustralia, Energy Consumers Australia (ECA), GreenSync, Redback Technologies, the South Australian Council of Social Service (SACOSS), the SA Government, the South Australian Wine Industry, Tesla, The Energy Project and Total Environment Centre.

In summary, some submissions have indicated their support for SA Power Networks' strategy to deal with the energy transition, specifically its DSO transition project, while others questioned whether SA Power Networks has provided a complete picture of its DER management expenditure. Given the energy transition underway, a number of submissions have requested that we investigate whether SA Power Networks has done as much as it can to avoid repex through enhanced analytics and information management provided by ICT investment, demand management and non-network solutions. Others questioned the prudency and efficiency of the SA Power Networks' non-network related expenditure, in particular whether SA Power Networks' ICT forecast benefits are fully justifiable and are resulting in reduced opex.

A.1.1 SA Power Networks' forecasting methodology

In coming to our position, we have had regard to SA Power Networks' investment governance framework and the application of top-down checks.

Investment governance and top-down Challenge

As part of its regulatory proposal, SA Power Networks explained that its Distribution projects are overseen by its Regulated Works Program (RWP) governance framework, which establishes the hierarchy of responsibilities.[18] A key component of the RWP's planning process is the development of the Strategic Plan, which is accompanied with a five-year financial plan. The annual budget, for each year of the internal five-year financial plan, is developed annually and is submitted to the Board for approval.

In its regulatory proposal, SA Power Networks noted that its annual budget includes detailed estimates of SA Power Networks capex that will be used for its performance measurement. During a meeting with SA Power Networks, it explained that it is during the annual budgeting process that SA Power Networks undertakes detailed option and

17 AER, *Draft decision - SA Power Networks distribution determination 2020–25 - AER capital expenditure assessment outline*, October 2019.

18 SA Power Networks, *2020–25 Regulatory Proposal - Supporting Document 5.2 - Expenditure Governance Procedures*, January 2019.

cost-benefit analysis. We understand that a similar detailed option and cost-benefit analysis is not undertaken at the regulatory proposal stage.

SA Power Networks also advised the AER Regulatory Determination is used to 'inform' SA Power Networks' capital planning. In a response to an information request it confirmed that,

> '…Departmental Managers consider AER approved expenditure forecasts as the initial basis in the preparation of departmental budgets within the 5 year Regulatory Control Period (RCP).'

EMCa has observed that SA Power Networks' governance framework is generally consistent with industry practice, however, EMCa noted a number of concerns with the practical application of its governance and management elements and the effect that it may have on its ex-ante forecast. We agree with EMCa that the practical application of the SA Power Networks' governance and management framework, when observed in conjunction with a consistent pattern of underspending relative to the capex allowance, indicates a bias towards over-forecasting its capex requirements at the regulatory determination stage. We have had regard to EMCa's observation, as context, in forming our view on the prudent and efficient level of expenditure over the forecast period.

For example, EMCa has made the following observations during its review of aspects of SA Power Networks' capex forecast:

- ICT capex - EMCa observed that elements of SA Power Networks' IT governance and management framework are generally consistent with industry practice and also stated that SA Power Networks' cost estimate methodology are appropriate.[19] EMCa acknowledged that SA Power networks has taken steps to assess the risk of delivery; however, there remains a material delivery risk at a project level and, because of the project interdependencies, at a portfolio level for its ICT capex.
- Connections' capex forecast - EMCa acknowledged that the SA Power Networks' economic model (BISOE)[20] is helpful and necessary, however, EMCa observed that it was not evident that the connections' capex forecast was subject to a top-down review or challenge at a management level. EMCa stated that a top-down challenge is likely to challenge the bottom-up assumptions in the context of the Board's strategic objective and vision for SA Power Networks, particularly given that SA Power Networks' net connections capex forecast is higher than its current regulatory control period. [21]

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[19] Energy Market Consulting Associates, *Review of aspects of SA Power Network's capital expenditure*, September 2019, p. 27.

[20] SA Power Networks engaged BISOE to produce its connections capex forecasts. BISOE developed a model for each identified connections category, which was underpinned by key drivers identified for each category.

[21] Energy Market Consulting Associates, *Review of aspects of SA Power Network's capital expenditure*, September 2019, p. 85.

- Repex forecast - EMCa observed a disconnect between the tool used to deliver repex and the tool used to forecast it. SA Power Networks relies on a value-based visibility approach to deliver, select and prioritise work. However, for 44 per cent of forecast repex, SA Power Networks has relied on the Condition Based Risk Management (CBRM) tool. EMCa has observed that the CBRM tool has conservative risk and consequence values, which are likely to overstate the forecast.[22] Therefore, SA Power Networks' work scheduling, based on its value and visibility approach, is likely to lead to SA Power Networks incurring a lower level of repex than proposed, as evident in the first three years of the current regulatory control period.[23]

In addition, our review highlighted that it was not evident that the augex forecast was subject to a top-down review. We have identified a lack of acknowledgement of the interrelationship between projects. A good example is in the DER management expenditure, where SA Power Networks' projects appear to be ad-hoc and do not appear to have considered the interrelationships that exist between projects. EMCa made similar observations with regards to two of SA Power Networks' DER management related projects.[24]

A.1.2 Modelling adjustments as part of our substitute estimate

We have made a number of modelling adjustments in our draft decision. We have updated the estimated 2018–19 CPI figure with actual CPI, which was lower than SA Power Networks' forecast CPI at the time of submission. We have also made adjustments to SA Power Networks' real cost escalations. Both adjustments have resulted in a reduction of $33.7 million ($2019–20) or two per cent from SA Power Networks' initial proposal of $1719.7 million.

Real cost escalation adjustment

SA Power Networks has applied a real cost escalation to reflect cost escalation for its labour and contract labour over the 2020–25 regulatory control period. For the labour escalation component, our draft decision on capex has adopted the wage price growth as applied to opex and as discussed in attachment 6 of this draft decision.

For the contract labour component, our substitute capex estimate has not allowed any contract labour escalation. SA Power Networks has relied on wages growth in the state's construction industry as proxy for contract labour escalation.[25] We have

22 Energy Market Consulting Associates, *Review of aspects of SA Power Network's capital expenditure*, September 2019, p. 107.

23 Energy Market Consulting Associates, *Review of aspects of SA Power Network's capital expenditure*, September 2019, p. 115.

24 Energy Market Consulting Associates, *Review of aspects of SA Power Network's capital expenditure*, September 2019, p. iii.

25 SA Power Networks, *2020–25 regulatory proposal - Supporting Documentation 6.6 - BIS Oxford Economics utilities construction wage forecasts to 2024–25*, October 2018, p. 32.

requested existing contracts that have the forecast escalations as predicted in SA Power Networks' regulatory proposal. SA Power Networks was unable to provide any existing contracts or service agreements to demonstrate that the real cost escalation are, in fact, reflective of its agreed contracts.[26] In addition, we have observed that, approximately 50 per cent, of the total contract labour cost escalation, which is a construction industry proxy, is applied to SA Power Networks' ICT forecast. SA Power Networks acknowledged that the choice of the wage price index that is applied to contracted ICT expenditure may require reconsideration.[27] Our draft decision, consistent with previous determinations,[28] has not allowed contract labour price growth, unless the growth is evidenced in a distributor's contracts. We will have regard to further information in the revised proposal in determining our final decision on real cost escalation.

A.2 DER management expenditure

Distributed energy resources (DER) commonly refer to solar photovoltaic (PV), storage, electric vehicles, and other consumer appliances that are capable of responding to demand or pricing signals. Increasing DER penetration represents a change in the way that consumers interact with electricity networks and the demands that it places on networks. DER management expenditure is the expenditure which seeks to manage the growing effects of higher penetration of DER on the network, in particular the effects of solar PV and the impact on a distributor's ability to manage voltage within standards. SA Power Networks have included in its proposal a total augex forecast of $372.0 million, of which $106.6 million is attributable to DER management programs.

A.2.1 Draft decision

SA Power Networks identified its DSO transition program explicitly as a DER management program. However, it proposed three additional projects for strategic or capacity purposes, which have interlinkages and overlaps as DER management expenditure, or at least serve to address voltage management issues. As a result, we have considered these DER management related projects and their potential interactions together to best assess the efficiency of these projects.

We do not accept SA Power Networks' forecast of these projects totalling $106.6 million, as SA Power Networks has not satisfied us that its forecast forms part of a total capex forecast that reasonably reflects the capex criteria. We have instead included a substitute estimate of $75.4 million for DER management capex. This is 30.0 per cent lower than SA Power Networks' forecast for the selected projects, as shown in Table 5.4. We are satisfied that this amount reasonably reflects the capex criteria.

[26] SA Power Networks, *Information Request 69 - Escalation rate for contract labour repex*, 29 July 2019, p. 1.

[27] SA Power Networks, *Information Request 69 - Escalation rate for contract labour repex*, 29 July 2019, p. 2.

[28] AER, *Final Decision Australian Gas Networks Access Arrangement 2016–21 - attachment 6, May 2016,* p. 43.

Table 5.4 Draft decision on SA Power Networks' DER management expenditure ($ million, 2019–20)

Category	Proposal	Our substitute estimate	Difference (per cent)
LV management program (DSO transition program)	30.3	30.3	-
Quality of supply (QoS)	44	38.1	-13.4
LV monitoring	18	0	-100.0
Voltage regulation	14.3	7	-51.0
Modelling adjustments		-0.7	
Total	**106.6**	**74.7**	**-30.0**

Source: SA Power Networks: *Reglatory proposal; response to information request 8*, AER analysis.

Note: The modelling adjustments relates to changes to CPI and labour cost escalations, which are discussed in section A.1.2 of this attachment.

A.2.2 SA Power Networks' proposal

SA Power Networks proposed a combined $106.6 million for the four programs we have considered separately as DER management capex. These projects are:

- DSO transition - a new program to develop new operational systems and business processes to facilitate management of solar PV, battery storage and virtual power plants through a DSO framework.[29] This program is associated with a $3.8 million opex step-change.
- Quality of supply (QoS) program - a program to investigate customer QoS inquiries received from customers, implement corrective action including network augmentation where required, and to manage the low voltage network in compliance with regulatory obligations.
- LV monitoring program - an extension of its existing program by installing a further 2,250 remotely-readable monitors on its network, in order to be able to remotely monitor its LV network without the need to physically conduct tests.
- Voltage regulation program - a proposal to replace eight transformers with modern equivalents, to conform to its obligations and manage voltage issues as a result of PV.

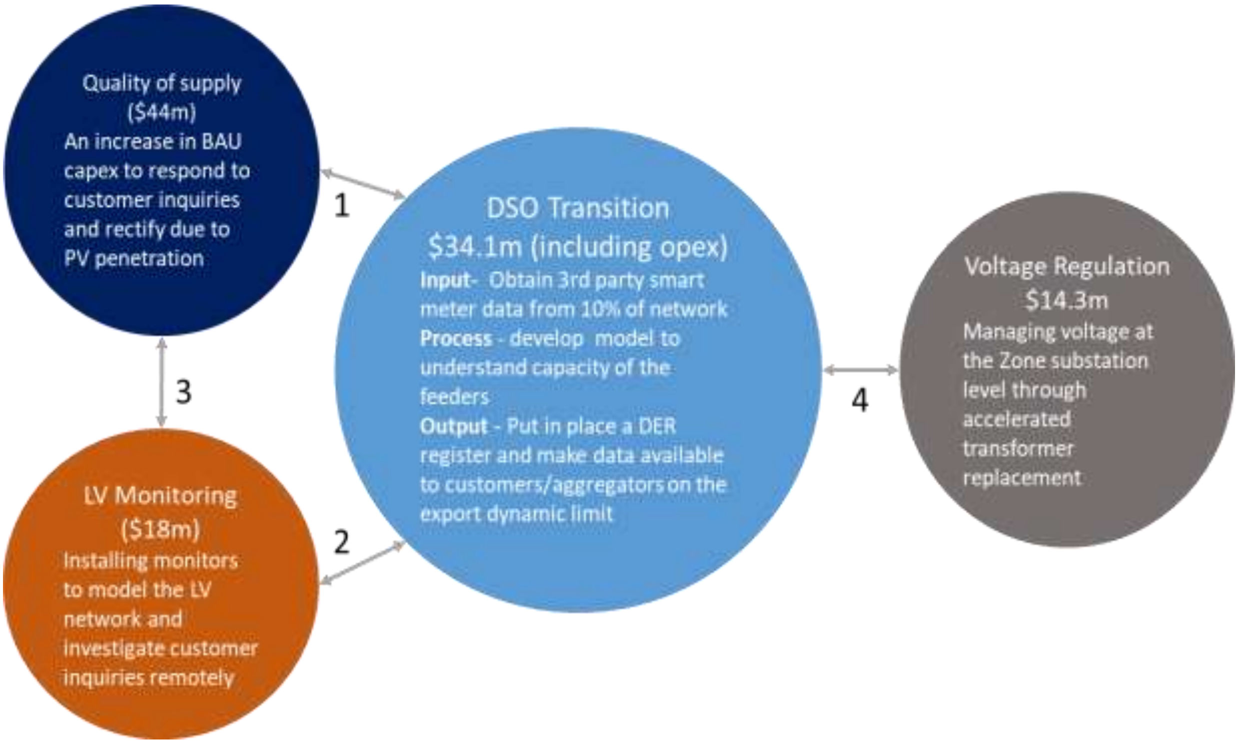
[29] SA Power Networks, *2020–25 regulatory proposal – attachment 5 – Capital expenditure*, January 2019, p. 76.

A.2.3 Reasons for draft decision

SA Power Networks has satisfied us its DSO transition program forecast reasonably reflects the capex criteria, however, it has not justified the forecast capex for the QoS, LV monitoring and voltage regulation programs. In coming to our position, we have assessed all the information before us. We have also had regard to stakeholder submissions, including from the SA Government, SACOSS and ECA.

SA Power Networks proposed the DSO transition program to manage high voltage conditions on low voltage feeders, and to manage other constraints on its network.[30] It has also proposed a number of interrelated projects. SA Power has not identified how the combination of solutions could work together to manage voltage issues. Even though SA Power Networks adopted the DSO transition program as its preferred solution over alternatives such as traditional augmentation, it still proposed traditional augmentation through the QoS program. This indicates that the interrelationships have been considered but not fully recognised in the regulatory proposal, and there may be scope to lower the expenditure forecast. This is reflected through our substitute forecast for the projects that we consider are interrelated. Our understanding of the programs that have linkages is highlighted in Figure 5.3.

Figure 5.3 Interrelationships in SA Power Networks' proposed DER management programs



Source: AER analysis.

30 SA Power Networks, *2020–25 regulatory proposal - Supporting documentation 5.18 - LV management business case*, January 2019, pp. 3–4.

The numbers shown in the Figure 5.3 are discussed in turn.

1. **DSO transition program and QoS:** if the DSO transition program is successful, export of PV electricity may be restricted at times and in areas where voltage limits are likely to be exceeded. If voltage standards are not exceeded, there may not be a need for QoS as proposed because:

- SA Power Networks would be able to address localised voltage issues as they develop, avoiding the need to investigate issues when raised by customers
- SA Power Networks may be able to prevent the emergence of localised voltage issues entirely.

Based on the above, and other reasons discussed below, SA Power Networks will be able to manage QoS issues at recent expenditure levels rather than incur steadily increasing costs as it forecasted.

2. **DSO transition program and LV monitoring program:** SA Power Networks indicated that the LV monitoring program provides a capability to install additional monitors to support the introduction of dynamic constraint management (similar to the proposed solution behind the DSO transition program). SA Power Networks' proposal did not discuss the interrelationship.[31]

   In our view, SA Power Networks has not justified why it requires monitoring at two different levels of the LV network, that is, at the household level (through smart meter data) and at the feeder level. It would appear that there is limited incremental benefit to obtaining monitoring data from both sources. This is one reason for not including the LV monitoring program in our substitute forecast.

3. **LV monitoring program and QoS program:** SA Power Networks has stated that the LV monitoring program has been justified on the basis of improving business as usual quality of supply process efficiency. It does not appear that SA Power Networks has accounted for this relationship in its proposal. EMCa has made a similar observation and indicated that if the LV monitoring is accepted, then there would need to be an offsetting reduction to the QoS program.

4. **DSO transition program and voltage regulation program:** if the DSO transition program is successful, SA Power Networks may be able to manage voltage without the need for early transformer replacement. However, it is uncertain whether the DSO transition program would eliminate the voltage issues in the short-term. As such, we accept that the some level of expenditure is needed for the voltage regulation program, but consider that SA Power Networks' proposed solution for the voltage regulation program is not the most efficient option.

Our assessment of the four programs is discussed below.

31 SA Power Networks, *Distribution system planning report*, January 2019, p. 96.

DSO transition program

We have included the DSO transition program in our substitute forecast, SA Power Networks has demonstrated the need and that it is the least-cost option. We have also accepted the associated opex-step change, which is discussed in attachment 6 of this draft decision.

SA Power Networks submitted that PV is increasingly causing voltage non-compliance problems as the installed base of PV grows. SA Power Networks must invest to maintain compliance with QoS standards, particularly voltage standards.[32] To achieve compliance, it proposed to enable dynamic export limits, which will allow the export of electricity to the network based the network's hosting capacity on a locational and time varying basis. This would allow customers' exports to only be limited at times and in locations where there is a constraint, such as a voltage constraint.[33]

There was wide support from stakeholders for the program, including from the SA Government, the CSIRO, the Clean Energy Council, Greensync, Redback Technologies, Tesla and the TEC.[34] However, SACOSS, CCP14 and ECA submitted that SA Power Networks had not made the total cost of managing DER clear to customers, and that we should consider this proposal in the context of other programs that SA Power Networks had proposed.[35] The Energy and Water Ombudsman SA provided information showing that the number of PV-related complaints it has received relating to constraints has steadily increased over the past four years.[36]

SA Power Networks has evidenced high-voltage inquiries that were attributable to solar PV, which demonstrates a potential voltage non-compliance issue.[37] SA Power Networks has also modelled the effect of voltage issues in its cost-benefit analysis, it iteratively examined the voltages over time as PV exports increased due to additional PV installations. SA Power Networks' assessment of its voltage issues and modelling approach is thorough. Growth in customer high-voltage complaints correspond with the growth in PV, where PV penetration rates are high relative to the base load on the LV

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32 NER, cll. 5.2.1(a)(3), 5.2.3(b); *South Australia Electricity (General) Regulations* (2012), regulation 46(a).

33 SA Power Networks, *2020–25 regulatory proposal - Supporting documentation 5.18 - LV management business case*, January 2019, p. 10.

34 SA Minister for Energy and Mining, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019, p. 1; CSIRO, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019; Clean Energy Council, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019; GreenSync, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019; Redback Technologies, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019; Tesla, Submission on SA Power Networks regulatory proposal 2020–25, May 2019; Total Environment Centre, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019.

35 South Australian Council of Social Service, *SACOSS submission in response to AER issues paper on the SA Power Networks' electricity determination 2020-2025*, May 2019, pp. 8-10; CCP14 – Advice to the AER on the SA Power Networks 2020–25 regulatory proposal, May 2019, p. 40; Energy Consumers Australia, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019, p. 42.

36 Energy & Water Ombudsman SA, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019, pp. 1–2.

37 SA Power Networks, *Information request 20*, 1 May 2019, p. 6.

feeders. Inquiries may continue to increase as PV penetration levels are expected to increase further, and SA Power Networks will need to take additional measures to ensure compliance with its obligations.

SA Power Networks has developed a business case and a comprehensive cost-benefit analysis, which estimates the benefits.[38] Based on all information before us, we observed that:

- SA Power Networks considered a reasonable range of solutions, such as traditional augmentation, limiting PV export and variants of its preferred dynamic export limit approach (the DSO transition program).[39] We considered the capabilities of these solutions and other solutions to manage voltage issues in the long-term. The other solutions include adjusting distribution transformer settings, managing the float voltage at zone substations, and installation of voltage regulators. Compared to other options, the DSO transition program is more likely to address voltage compliance on a broad scale across the network because it is not limited to addressing local voltage non-compliance alone.
- SA Power Networks and its advisers (KPMG) provided information on the cost build-up of each of the program's components. The costing for the proposed capex was based on, where appropriate, KPMG's analysis, third party quotes and standard market rates (that have been market tested for external contractors). The information showed that the estimated capex for the program had been refined down from $54.1 million to $33.3 million (including overheads).[40] We have not identified any unexplainable or unnecessary costs included in this cost estimate and accept it on the grounds that it is based on best current information, including market tested rates.
- The benefit calculated in the model is predicated on maintaining voltage standards while enabling PV export and focuses on the value of PV export. To calculate PV export, the model relies on one input value based on the marginal cost of wholesale generation. While the analysis is comprehensive, the use of the single value is a limitation as it may not reasonably reflect the behaviour of the market or the impact of the network's limitations. PV inverters will be constrained at different times and for varying lengths of time based the density of PV in an area, local demand relative to local PV generation, and the characteristics of the network such as topography. Similarly, the marginal cost of wholesale generation differs over any given day, such that the marginal cost of generation and localised PV constraints need to be aligned to determine the value of foregone PV export.

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[38] SA Power Networks, *EA Tech - LV management strategy*, December 2018; SA Power Networks, *EA Tech - LV management strategy An 1 DER hosting capacity assessment*, November 2018; SA Power Networks, *EA Tech - LV management strategy An 2 development of the transform model*, November 2018.

[39] SA Power Networks, *2020–25 regulatory proposal - Supporting documentation 5.18 - LV management business case*, January 2019, January 2019, pp. 9–11.

[40] SA Power Networks, *KPMG - Future network strategy - technology costs*, November 2018, p. 8.

- Even though SA Power Networks has demonstrated some benefits of the DSO transition program, we acknowledge that the extent of the benefits that may be realised remains unclear. We also note that benefits may extend to areas beyond those SA Power Networks has quantified.[41] As such, there would be significant value in undertaking a post-implementation review to demonstrate the benefits realisation over time. The review would also provide learnings for the industry in terms of the benefit realisation and the deployment and operation of a DSO solution.

On balance, the proposed costs are reasonable, and SA Power Networks' proposed DSO solution program is likely to be the least-cost solution to maintain voltage compliance as solar PV installations increase.

Quality of supply program

SA Power Networks proposed an annual increase in expenditure of $400,000 per annum (including overheads), to augment the network due to increases in customer-related PV inquiries on the LV network. EMCa has reviewed the QoS proposal and does not consider the full amount of proposed augex is required, it observed that:

- SA Power Networks' historical-cost trend methodology is limited, as it only relies on four data points with the latest being calendar year 2017. Data for 2018 showed that the trend appears to be rising at a rate less than SA Power Networks' original forecast.[42]
- SA Power Networks' historical trend forecasting methodology has some merit, but should serve as a starting point only. In its view, SA Power Networks should consider the effect of changes it recently implemented, or proposes to implement, to mitigate against QoS issues and remediation costs, which include:[43]
    - the ongoing reduction in overvoltage excursions from both the 'enforcement' of AS4777 standards and the likely effect of increasing penetration of more sophisticated rooftop PV inverters
    - the effect of proposed tariff changes, which are designed to encourage customers to shift load to the middle of the day (i.e., when there is a surplus of rooftop PV generation).[44] We have accepted SA Power Networks' proposed tariff structure statement, which is discussed in attachment 18 of this draft decision.

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41 SA Power Networks, *2020–25 regulatory proposal - Supporting documentation 5.18 - LV management business case*, January 2019*, January 2019*, pp. 18–20.

42 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, pp. 69–73.

43 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 71.

44 SA Power Networks, *attachment 17 – Tariff structure statement*, January 2019, p. 32.

EMCa submitted that the AS4777-related effect and the effect of other initiatives are collectively likely to offset the potential for increases in QoS inquiries and costs.[45] We considered EMCa's analysis and agree that the QoS capex is overstated. As mentioned earlier, SA Power Networks has proposed other programs, which are likely to reduce its business as usual QoS augex, such as the DSO transition and the LV monitoring program, without identifying the interrelationships.

Therefore, SA Power Networks has not established that its total proposed QoS is prudent and efficient. We have included $38.6 million in our substitute estimate, which is consistent with SA Power Networks' 2018 expenditure level, as we recognise there will be ongoing future costs to manage QoS and the most recent year is reflective of SA Power Networks' efficient capex.

As our substitute estimate is based on 2018 expenditure level and our decision on LV monitoring (discussed below), we have not taken into account the effect that the LV monitoring program may have on the QoS program.[46] EMCa's view is that if we were to approve the proposed LV monitoring program, the identified benefit of monitoring should be realised through lower investigation costs incurred through the business as usual QoS program, which would be at a level below actual expenditure. [47]

LV monitoring program

We have not included this program in our substitute forecast. SA Power Networks has not justified that its LV monitoring program is required in order to maintain service standards or is a regulatory obligation. Our review has identified that SA Power Networks has not tested the efficiency of its forecast as it has not considered a range of options, such as acquiring smart meter data. In addition, SA Power Networks submitted that its cost-benefit modelling is net present value (NPV) positive, however, our analysis indicates that the benefits are overstated for the following reasons:

- SA Power Networks calculates a benefit in the avoided cost of responding to inquiries in person. In calculating this benefit, it assumed that three hours is required for every logger installation, however, SA Power Networks has not justified the basis of this assumption.
- SA Power Networks calculates benefits from avoided transformer test work and avoided customer inquiries via proactive work. The benefits are calculated based on a forecast of completed customer inquiries that uses a simple linear regression on the recent six years. It is unclear why this trend would continue given the other measures being implemented, including tariff changes, enforcement of AS4777 and the DSO transition program.

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45 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 72.

46 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, pp. 70, 79; SA Power Networks, *Distribution system planning report,* January 2019, p. 100.

47 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 78.

- SA Power Networks has not demonstrated why two surveys are normally required as a response to every customer inquiry.

We have also considered the interrelationship between proposed DSO transition and LV monitoring programs. It is unclear why SA Power Networks requires monitoring at two different levels of the LV network, at the household level (through smart meter data, proposed to be purchased through the DSO transition program) and at the feeder level. SA Power Networks has not established that the LV monitoring program is prudent and efficient as it has not demonstrated the benefit of obtaining monitoring data from both sources.

Voltage regulation program

SA Power Networks has not demonstrated that its proposed $14.3 million to replace eight transformers in five substations is the most efficient option to rectify PV voltage issues.[48] We reviewed SA Power Networks' cost-benefit analysis and identified:[49]

- SA Power Networks has not accounted for the benefit of deferring transformer replacement under the option to install voltage regulators. Once the deferral benefit is incorporated, installation of voltage regulators becomes the preferred option for four of the five substations.
- SA Power Networks' alternative option, which was to install voltage regulators, used an estimated unit rate for voltage regulators, which is considerably higher than what we have observed from other distributors, and is likely to overstate the average cost of voltage regulator installations.

SA Power Networks has demonstrated that it is prudent to mitigate the voltage issue, however, it has not established that its preferred option is the most efficient option. We have included $7.3 million for voltage regulation in our substitute forecast. This is consistent with the installation of voltage regulators for four out of its proposed five substations using our revised estimate of voltage regulator costs, and the cost of replacement of the transformers at the remaining substation.

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48 SA Power Networks, *Information request 59*, 2 July 2019.

49 SA Power Networks, *Information request 56 – Q1-LV monitoring cost benefit analysis*, 1 July 2019.

A.3 Augmentation expenditure

Augmentation is typically triggered by the need to build or upgrade the network to address changes in demand and network utilisation. However, it can also be triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements.

A.3.1 Draft decision

As discussed in A.2, we have considered DER management capex separately. Of the $372.0 million proposed, we have assessed $265.4 million as part of standard augex. SA Power Networks has not demonstrated that its forecast augex of $265.4 million is prudent and efficient. We have instead included a substitute estimate of $187.3 million for augex, which is 29.4 per cent lower than SA Power Networks' augex forecast. We are satisfied that this amounts reasonably reflects the capex criteria.

Table 5.5 summarises SA Power Networks' proposal by augex subcategory and our substitute estimates.

Table 5.5 Draft decision on SA Power Networks' total forecast augex ($ million, 2019–20)

Category	Proposal	Position	Difference (per cent)
Capacity	70.8	52.5	-25.8
Reliability	61.8	30.8	-50.1
Strategic	16.3	8.3	-48.9
Safety	54.7	35.9	-34.5
Environmental	9.3	9.3	-
PLEC	52.5	52.5	-
Modelling adjustment		-2.0	
Total	**265.4**	**187.3**	**-29.4**

Source: SA Power Networks proposal, response to information request 8, AER analysis. Numbers exclude DER management related capex.

A.3.2 SA Power Networks' proposal

SA Power Networks proposed $372.0 million[50] of augmentation expenditure for the 2020–25 regulatory control period. This represents a 6.4 per cent decrease on the

[50] Inclusive of $106.6 million that we have assessed as DER management.

$397.5 million that it expects to incur over the 2015–20 regulatory control period. SA Power Networks submitted that its proposal comprises the following key components:[51]

- Capacity driven augmentation – works required to meet forecast demand that necessitate the extension or upgrade of our sub-transmission, distribution and LV networks;
- Reliability – installation of assets required to maintain the reliability of the network to ensure compliance with the Essential Services Commission of South Australia's (ESCoSA) defined reliability service standards;
- Strategic – specific one-off programs to manage key network risks and compliance issues and/or optimise long term expenditure;
- Environmental – works necessary to address environmental risks within the network to comply with Environmental Protection Authority (EPA) requirements;
- Safety – expenditure necessary to maintain the safety of its network (excluding repex) for SA Power Networks' workforce and the general public and include a number of initiatives arising from its customer engagement program; and
- Power Line Environmental Committee (PLEC) – expenditure to underground parts of the network in accordance with State Government legislation.

A.3.3 Reasons for our position

SA Power Networks has not demonstrated that its capex for capacity, reliability, strategic and safety augex are prudent and efficient. SA Power Networks has justified its forecast for PLEC and its environmental-related augex, as it has demonstrated the need and the efficient level of capex required to comply with a number of legislative and regulatory obligations.[52] In coming to our position, we have assessed all the information before us,[53] including EMCa's independent advice and stakeholder submissions. Our assessment of the capacity, reliability, strategic and safety subcategories of augex are discussed in turn below.

Capacity

We have included $52.5 million in our substitute estimate for capacity augex. The difference between SA Power Networks' proposed capacity augex and our substitute estimate relates to two programs, namely, the augmentation of the Myponga – Square Water Hole 66kV line and the Athol Park – Woodville 66kV line.

These projects are intended to minimise the duration of network outages. SA Power Networks does not forecast peak demand to grow in the respective areas, rather it finds that at current loads, the projects would be NPV positive based on the value of

51 SA Power Networks, *2020–25 regulatory proposal – attachment 5 – capital expenditure*, January 2019, p. 57.

52 *Environment Protection Act 1993* (SA), *Environment and Protection Act 1993* (SA), s. 25 and *South Australian Electricity Act*, s. 58A.

53 This includes information requests received throughout the review process.

the unserved energy at risk. EMCa has reviewed both projects and conclude that SA Power Networks has not demonstrated that either project is prudent or efficient.

EMCa highlighted issues with the evidence provided in support of the Myponga – Square Water Hole 66kV line including the following:[54]

- The load forecast indicates stable peak demand, but the modelling contains inconsistent load factor assumptions. The modelling also appears to use non-coincident peak load data when coincident data is likely to be more appropriate given the customer mix in the areas supplied by the existing feeders.
- SA Power Networks' consideration of alternative options was insufficient. EMCa considered that alternative solutions such as reliability improvement of the Willunga-Myponga line and enhancing Starfish Hill wind farm should be evaluated further.
- Sensitivity analysis is likely to determine that positive market benefits are unlikely to be realised under most reasonable scenarios.

With regard to the Athol Park – Woodville 66kV line, EMCa considers that SA Power Networks' cost-benefit analysis should include more robust options and sensitivity analysis:[55]

- Options analysis should be broadened to include options to defer the required capex, suggesting that enabling dynamic line rating or changing the impedance of lines to alter power flows may be a lower cost solutions.
- Sensitivity analysis should include the effects of DER and other initiatives on peak load flows, because augmentation may not be the most appropriate solution in many scenarios.

We have had regard to EMCa's advice and agree with its conclusions. We have not included an allowance for the two projects in our substitute estimate, however, we will consider any additional supporting material in making our final decision.

Reliability

We have included $30.8 million in our substitute estimate for reliability augex. The difference between SA Power Networks' proposed capacity augex and our substitute estimate relates to three programs, namely, maintain underlying reliability, low reliability feeders and hardening the network. Each are discussed in turn below.

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54 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, pp. 75-77.

55 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, pp. 79-80.

Maintain underlying reliability

SA Power Networks has not justified the need for additional expenditure beyond its current period levels to maintain the reliability performance of its network as detailed in the South Australian Electricity Distribution Code. We have assessed SA Power Networks' reasons for the step-up and observed the following:

- SA Power Networks described that a specific colony of bats are having an increasing impact on the reliability of its network, and that this trend may continue.[56] Our analysis has identified that SA Power Networks used its resources effectively to steadily improve its system average interruption duration index (SAIDI) since 2010–11, particularly with respect to outages caused by weather and equipment failure.[57] Therefore, SA Power Networks has not demonstrated that it requires additional funding to maintain its reliability. To the extent that SA Power Networks needs to address outages caused by the colony of bats, it could reallocate expenditure from other areas and maintain reliability at current SAIDI levels. Similarly, we have identified that SA Power Networks' system average interruption frequency index (SAIFI) performance has steadily improved since 2009. The only exception relates to SA Power Networks' CBD SAIFI, which is expected to be addressed through the 11 kV PILC cable repex program, which is discussed in A.5 of this draft decision.
- SA Power Networks foresee additional effort and expenditure in complying with ESCoSA's new regional performances reporting obligations.[58] ESCoSA examined the regional reliability of ten regions and observed that SAIDI levels had either been steady or improved slightly in all but one region.[59] In the absence of evidence that reliability performance was declining across rural areas, it considered an enhanced reporting and monitoring regime to be a proportionate response to stakeholder concerns. However, ESCoSA expected SA Power Networks to maintain regional reliability, using its existing resources.[60]

SA Power Networks has not demonstrated it requires additional expenditure to maintain its existing level of reliability, therefore, our substitute estimate is consistent with SA Power Networks' expenditure over the current period.

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56 SA Power Networks, *2020–25 regulatory proposal - Supporting document 5.25 - Reliability & resilience management strategy*, January 2019, p. 32; SA Power Networks, *Information request 15*, 3 April 2019, pp. 5–7.

57 SA Power Networks, *2020–25 regulatory proposal - Supporting document 5.25 - Reliability & resilience management strategy*, January 2019, p. 32.

58 Essential Services Commission of South Australia, *SA Power Networks reliability standards review – Final Decision*, January 2019, p. i.

59 Essential Services Commission of South Australia, *SA Power Networks reliability standards review – Final Decision*, January 2019, p. 24.

60 Essential Services Commission of South Australia, *SA Power Networks reliability standards review – Final Decision*, January 2019, p. 24.

Low reliability feeders

SA Power Networks has not demonstrated that its forecast of $14.2 million to improve the reliability of supply to low reliability feeders is prudent and efficient.[61] ESCoSA requires SA Power Networks to identify and monitor its worst performing feeders, however, there is no direct obligation to improve the supply from these feeders.[62] SA Power Networks considers that there is still an expectation that it will reduce the poor performance of those feeders, where it is economically viable, and cites customer support for the program, as demonstrated in a survey.[63] SA Power Networks cites a need under the NER to address customer's concerns.[64]

In coming to our position, we have had regard to ESCoSA's recent review of SA Power Networks' reliability standards.[65] ESCoSA's review does not support the results of SA Power Networks' survey of support for the low reliability feeder program, as it noted the following:

- The reliability standards for the 2020–25 regulatory control period will require SA Power Networks to maintain reliability at current levels, rather than improve or reduce performance.[66]
- ESCoSA engaged Oakley Greenwood who surveyed these customers' willingness to pay for a five per cent and 10 per cent reliability improvement in their own area, and found that only a majority of metropolitan business customers were willing to pay some amount for an improvement.[67] In all other scenarios, 60 per cent or more of customers sampled were not willing to pay any amount for reliability improvement.
- Oakley Greenwood also assessed the economic efficiency of potential improvements and concluded that only one reliability improvement package had a net benefit – a 10 per cent improvement to reliability on low reliability feeders, however, only 1 in 4 customers were willing to pay for this improvement.[68] In all other instances the annualised cost exceeded the benefit.

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61 SA Power Networks, *2020–25 regulatory proposal – attachment 5 – capital expenditure*, January 2019, p. 71.

62 SA Power Networks, *Supporting document 5.27 Reliability & resilience management programs – low reliability feeder*s, January 2019, p. 4.

63 Following discussion of the program, consumers and stakeholders were asked to what extent they supported the program - 70 per cent indicated support and 30 per cent were uncertain. See SA Power Networks, *2020–25 regulatory proposal - Supporting document 0.13 - AnnShawRungie capex deep drive workshops report*, July 2018, pp. 6, 8.

64 NER, cl. 6.8.2(c1).

65 Essential Services Commission of South Australia, *SA Power Networks reliability standards review – Final Decision*, January 2019.

66 Essential Services Commission of South Australia, *SA Power Networks reliability standards review – Final Decision*, January 2019, p. i.

67 Oakley Greenwood, *Economic assessment of electricity distribution reliability standard package*s, June 2018, pp. 4–5.

68 Oakley Greenwood, *Economic assessment of electricity distribution reliability standard packages*, June 2018, p. 39.

SACOSS and ECA questioned the level of reliability capex proposed in the context of ESCoSA's review, particularly the premise of maintaining reliability.[69] CCP14 states its support for the ESCoSA review and noted that the stakeholders did raise the issue of low reliability feeders during regional engagement sessions, but CCP14's view was that the case had not been made for alternative options such as local generation.[70] On the other hand, Business SA acknowledged that only one in four were willing to pay to fund reliability improvement, however, it noted there is one reliability improvement scenario with a net benefit and suggested that it be considered further. It explained that, when customers fund their own reliability improvements, it results in a high cost for those customers. It added that the results may have varied, if customers were asked to pay for reliability improvement, on the basis that all customers contribute to the improvement, as would be the case with South Australian state-wide pricing.[71] We have considered Business SA's submission, however, to-date, we have not received any evidence, or analysis, to support that there is a net benefit, if all customers fund low reliability feeders' improvement.

In the absence of any regulatory requirement to undertake the program, SA Power Networks has not demonstrated that that the program is prudent, therefore, we have not included the low reliability feeder program in our substitute forecast.

Hardening the network

SA Power Networks has not demonstrated that its capex forecast of $14.6 million to harden the network, or improve reliability, in locations which are consistently affected by Major Event Days (MEDs) is prudent and efficient.[72]

Even though SA Power Networks does not have absolute obligations to mitigate MED interruptions to customers, it considers that there is an expectation for some level of augmentation where it is economic to do so, and cites declining performance affected by MEDs and customer support for the program to mitigate these impacts on the network.[73] We have had regard to all the information before us, including stakeholder submissions, and we have a number of concerns with this program, namely:

- **Declining performance -** SA Power Networks explained its customers are being affected by increased outages and longer durations, during MEDs.[74] Further, it submitted that it is reasonable to assume that the recent deteriorating performance can be expected in the future, particularly due to the predicted future increases in

69 South Australian Council of Social Service, *SACOSS submission in response to AER issues paper on the SA Power Networks' electricity determination 2020-2025*, May 2019, pp. 13-15; Energy Consumers Australia, Submission on SA Power Networks regulatory proposal 2020–25, May 2019, p. 21.

70 CCP14*, Advice to the AER on the SA Power Networks 2020–25 regulatory proposal*, May 2019, p. 40.

71 Business SA, *Submission to AER on SA Power Networks 2020–25 regulatory proposal*, May 2019, pp. 5-6.

72 SA Power Networks, *2020–25 regulatory proposal – attachment 5 – capital expenditure*, January 2019, p. 70.

73 SA Power Networks, *2020–25 regulatory proposal - Supporting document 5.26 Reliability & resilience management programs – hardening the network*, January 2019, pp. 4, 37.

74 SA Power Networks, *2020–25 regulatory proposal - Supporting document 5.26 Reliability & resilience management programs – hardening the network*, p. 13.

severe weather events.[75] We recognise that SA Power Networks' reliability performance levels inclusive of MEDs have been declining from 2010 to date. However, SA Power Networks has acknowledged, it is under no absolute obligations to mitigate MED interruptions to customers.[76] SA Power Networks cites the need to comply with ESCoSA service standards for reliability as set out in Clause 2 of the South Australian Electricity Distribution Code (the Code).[77] However, the reliability measures mandated in Clause 2 of the Code exclude any unplanned interruptions that qualify as MEDs.[78]

- **Customer support -** SA Power Networks explained that the reliability and resilience of the network emerged as an important priority for customers and cites the need to address these concerns.[79] In a survey regarding customers support for hardening the network program, 58 per cent indicated their support and 33 per cent were uncertain. Some concerns regarding synergies between this program and other programs, such as repex and bushfire management, were also documented.[80] In our view, this is not sufficient evidence to indicate customer support, because of the limited sample size of the survey and the level of uncertainty from stakeholders in response to the question itself. Further, the survey results appear inconsistent with stakeholders' views, particularly regarding the need to improve reliability beyond its current levels.[81]
- **Economic benefits -** we have reviewed the modelling provided and consider that SA Power Networks has overestimated the effectiveness of the action it proposed to take to address faults. Examination of the historical fault records used in the analysis suggests that approximately 77 per cent of faults are unique in nature, that is, they occurred at a unique location along a given feeder and are unlikely to reoccur. SA Power Networks assumes that it can address these faults with circa 80 per cent effectiveness, and customers will see the full effect of that reliability improvement. In our view, the effectiveness of the proposed measures are overstated because customers may still experience outages if faults occur at other locations along a feeder.

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75 SA Power Networks, *2020–25 regulatory proposal - Supporting document 5.26 Reliability & resilience management programs – hardening the network*, January 2019, pp. 24–25.

76 SA Power Networks, *2020–25 regulatory proposal - Supporting document 5.26 Reliability & resilience management programs – hardening the network*, January 2019, p. 4.

77 SA Power Networks, *2020–25 regulatory proposal - Supporting document 5.26 Reliability & resilience management programs – hardening the network*, January 2019, p. 4.

78 South Australian Electricity Distribution Code, cl 2.2.1(a).

79 SA Power Networks, *2020–25 regulatory proposal - Supporting document 5.26 Reliability & resilience management programs – hardening the network*, January 2019, p. 37.

80 SA Power Networks, *2020–25 regulatory proposal - Supporting document 0.13 - AnnShawRungie capex deep drive workshops report*, July 2018, p. 21.

81 South Australian Council of Social Service, *SACOSS submission in response to AER issues paper on the SA Power Networks electricity determination 2020-2025*, May 2019, p. 15; Energy Consumers Australia, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019, pp. 21, 42.

Due to insufficient evidence of customer support, absence of a regulatory obligation and insufficient economic benefit to justify the proposed scope of the program, SA Power Networks has not demonstrated that its capex is prudent and efficient and we have not included this program in our substitute forecast.

Strategic

We have included $8.3 million in our substitute estimate for strategic augex. The difference between SA Power Networks' proposed strategic augex and our substitute estimate relates to SA Power Networks' proposed SCADA to substations program.

Supervisory Control and Data Acquisition (SCADA) to substations

SA Power Networks has not demonstrated that its proposed $7.8 million to deploy SCADA devices to rural zone substations is prudent and efficient.[82] We have reviewed SA Power Networks' modelling and identified that it overstates the benefits, for example:

- The assumption that the program would result in the avoidance of one outage every three years, due to in-service transformer failure. This is considerably more frequent than the typical in-service transformer failure. In addition, SA Power Networks did not take into account the actual condition of its transformers across its rural substation fleet, when making this assumption.
- The assumption that six visits per year per substation will not be required. SA Power Networks describe the site visits as relating to making substation equipment setting changes.[83] Site visits to make setting changes mostly relate to float voltage changes which may be seasonally set and are more likely require two or three site visits per year, rather than the estimate six visits.
- The assumption that the installation of SCADA will increase substation capacity by 0.5 per cent, deferring the need for augmentation. Only $17.7 million of the $372.0 million proposed augex is demand driven, and with continued growth in DER, future demand pressures that would require augmentation are likely to be limited.[84]
- A deferred repex benefit seems to be predicated on the assumption that if SA Power Networks installs SCADA it can avoid the failure of one or two reclosers on its substation feeders. SA Power Networks has not demonstrated how the installation of SCADA defers reclosers' repex.

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82 SA Power Networks, *2020–25 regulatory proposal – attachment 5 – capital expenditure*, January 2019, p. 74.

83 SA Power Networks, *2020–25 regulatory proposal - Supporting document 5.23 - DGA Consulting - Network control - projects review 2020–25*, January 2019, p. 9.

84 SA Power Networks stated that $18.6 million (including overheads) or 7 per cent of the proposed expenditure is dependent on the demand forecast. SA Power Networks, *2020–25 regulatory proposal – attachment 5 – capital expenditure*, January 2019, p. 63.

SA Power Networks has not established that its solution is prudent and efficient, as the benefits are overstated and do not exceed the cost. Therefore, we have not included this program in our substitute estimate.

Safety

We have included $35.9 million in our substitute estimate for safety augex, which included SA Power Network's forecast for bushfire mitigation, as SA Power Networks demonstrated that its forecast is prudent and efficient. The difference between SA Power Networks' proposed safety augex and our substitute estimate relates to its proposed substation security and fencing program, protection compliance and CBD 33 kV to 11 kV conversion. Each are discussed in turn below.

Substation security and fencing

SA Power Networks proposed to continue its long-term program to remediate inadequate substation security and fencing, with four or five sites to be upgraded per year.[85] It proposed to continue the current level of funding, which it states is $2.6 million per year ($2017, including overheads).[86] Our calculation of the five-year average (2015–2020, including estimated years) is approximately $2.4 million per year ($2017, including overheads). SA Power Networks has demonstrated an obligation to improve fencing and surveillance arrangements at its existing zone substations,[87] however, SA Power Networks' proposed capex is an unjustified increase in expenditure. We have included a forecast in our substitute estimate that is consistent with its actuals over the 2015–20 regulatory control period.

Protection compliance

SA Power Networks has not established that its proposed $12.7 million to manage the protection of its HV network is prudent and efficient.[88] SA Power Networks proposed a similar program in its 2015–20 regulatory proposal. In our previous determination, we did not accept the program as SA Power Networks had not demonstrated, in accordance with NER S5.1.9(c) and (f) that upstream assets would be damaged in the event that primary protection systems were to fail.[89] In particular, we considered that faults on rural distribution feeders would not be capable of damaging other parts of the network, and that the fault ratings on substation equipment would accommodate the relevant fault currents. We also identified that NDJ1 was not a new obligation and SA Power Networks was in compliance with its safety obligations.

We have the same concerns in this draft decision. In addition, SA Power Networks submitted that it its project is driven by the historical failure rate of reclosers, with at

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85 SA Power Networks, *Information request 15 – Substation fences & security asset plan*, 3 April 2019, p. 6.

86 SA Power Networks, *Information request 15 – Substation fences & security asset plan*, 3 April 2019, p. 7.

87 South Australia Electricity (General) Regulations 2012, cl. 51(1).

88 SA Power Networks, *Information request 1 - Asset plan 3.2.14 protection and control*, January 2019, p. 11.

89 AER, *SA Power Networks determination 2015–20: attachment 6 – capital expenditure, October 2015*, pp. 6-111-112.

least 55 failing each year.[90] However, it has not provided evidence that any of these failures, or a failure on the other single-wire earth return and 11kV feeders with known backup protection issues, would result in damage to upstream assets.[91] It is required to provide evidence that damage would result because, among other matters, clause S5.1.9 (f) of the NER requires that back-up protection operates to clear a fault of any fault type within a time that would not damage any part of the power system other than the faulted element. This requires consideration of the relevant fault clearance time of the primary protection system and whether damage could reasonably result if not for the timely action of the backup protection.[92]

We have not included the capex for protection compliance in our substitute forecast, but we will consider any additional supporting material in the revised proposal. We would require engineering analysis for a representative sample of feeders to demonstrate that the existing protection system on those feeders would not prevent upstream equipment damage in the event of a fault.

CBD 33 kV to 11 kV substation conversion project

SA Power Networks has not justified that seven of its CBD 33 kV distribution substations require replacement over the forecast regulatory control period. SA Power Networks submitted that the assets are in poor condition, and in order to comply with modern clearance standards, it would need to convert them to 11 kV and connect the substation to the existing 11 kV CBD network. SA Power Networks has not established the prudency and efficiency of the program, for the following reasons:

- SA Power Networks did not provide any condition reports that would demonstrate the poor condition of these assets, [93] however, in response to an information request, it provided a hazard assessment analysis, which identified a range of hazards. The hazards described do not justify the replacement of the substation.
- Five out of seven substations have transformers that are less than 35 years of age. In other cases, SA Power Networks has assumed a technical life of 65 years for its transformers fleet. Therefore, in the absence of any condition reports, it is unlikely that these transformers are in poor condition.
- SA Power Networks stated that it has not undertaken a defined scope of works necessary for this replacement, and as such it has not demonstrated its forecast capex is the most efficient option.

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90 SA Power Networks, *Information request 1 - Asset plan 3.2.14 protection and control*, 25 February 2019, p. 38.

91 SA Power Networks, *Information request 1 - Asset plan 3.2.14 protection and control*, 25 February 2019, p. 38.

92 "The only circumstance where a back-up system is not required to be provided under clause S5.1.9(c) and (f) is if the occurrence of a short circuit fault of any type that remains un-cleared would not cause damage to any part of the power system (other than the faulted element) while the fault current is flowing or being interrupted." SA Power Networks, *2020–25 regulatory proposal – attachment 5 – capital expenditure*, January 2019, p. 80.

93 SA Power Networks, *Information Request 044 – Augex and Repex*, 12 June 2019, public, p. 5.

SA Power Networks has not established the prudency or efficiency of its program, therefore, we have come up with a substitute estimate which is consistent with SA Power Network's average incurred capex over the 2015–18 regulatory years.

A.4 Customer connections

Connections capex is expenditure incurred to connect new customers to the network and, where necessary, augment the shared network to ensure there is sufficient capacity to meet the new customer demand.

A.4.1 Draft decision

We do not accept SA Power Networks' proposed forecast net connections capex of $202.9 million. SA Power Networks has not satisfied us that its forecast net connections capex reasonably reflects the capex criteria. We have included $166.5 million in our substitute estimate for connections, excluding overheads, consistent with SA Power Networks' actual/estimated expenditure in the 2015–20 regulatory control period. This is 17.9 per cent lower than SA Power Networks' net connections forecast.

We have included SA Power Networks' forecast of contributions ($199.3 million, excluding gifted assets), which is broadly consistent with the $199.8 million expected to be incurred in the current regulatory period.

A.4.2 SA Power Networks' proposal

SA Power Networks proposed $202.9 million in net connections capex. This represents a 14.9 per cent increase on current regulatory period net connections. SA Power Networks also proposed $199.3 million in capital contributions (excluding gifted assets). SA Power Networks has classified all connection services into the following four categories for the purposes of forecasting:[94]

- Minor customer connections ($57.0 million)
- Medium customer connections ($87.8 million)
- Major customer connections ($82.0 million)
- Real estate developments (-$10.9 million, contributions are forecast to be greater than gross capex)

[94] SA Power Networks, *2020–25 regulatory proposal – attachment 5 – capital expenditure*, January 2019, pp. 90-91; SA Power Networks, *Information request 8 – Capex program list*, 20 March 2019.

A.4.3 Reasons for draft decision

Stakeholders including CCP14, The Energy Project, SACOSS and ECA each considered that we should review SA Power Networks' connections forecast in detail recognising the increase in forecast expenditure.[95]

We identified that the increased forecast connections capex is primarily driven by the forecast of major customer connections, which is 40 per cent higher than the average level expected over the 2015–20 calendar years.[96]

SA Power Networks engaged BIS Oxford Economics (BISOE), who developed a top-down economic model for each connections category to serve as the basis for SA Power Networks' connections capex forecasts. Separately, BISOE and SA Power Networks also developed bottom-up forecasts for major customer connections for the earlier years of the 2020–25 regulatory control period, providing evidence of the major non-residential and engineering construction projects that are expected to be connected.[97]

We sought advice from EMCa that had a number of concerns with the connections forecast:[98]

- SA Power Networks' forecast of major customer connections is based solely on BISOE's top-down economic model. EMCa accepts that economic models are necessary to forecast connections capex because the certainty of bottom-up forecasts for new connected loads will deteriorate over the forecast period. SA Power Networks provided a considerable amount of contextual data and description of the models, however direct access to BISOE's models was not provided. EMCa was therefore unable to assess the reasonableness of the forecasts, including the key drivers and modelling assumptions. It is also unclear how the bottom-up forecast of major customer connections was used to support and verify the outcomes from the economic model.
- BISOE did not demonstrate its basis for forecasting 'Non-residential Commencements' (a component of the major connections forecast) to remain at approximately current levels throughout the 2020–25 regulatory control period. Other data sources appear to suggest that non-residential commencements may

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95 CCP14, *Advice to the AER on the SA Power Networks 2020–25 regulatory proposal*, May 2019, p. 42; The Energy Project, Submission: AER issues paper – SA Power Networks revenue determination 2020–2025 and customer connections, May 2019, p. 12; South Australian Council of Social Service, SACOSS submission in response to AER issues paper on the SA Power Networks' electricity determination 2020-2025, May 2019, p. 8; Energy Consumers Australia, Submission to AER issues paper: SA Power Networks electricity distribution determination, May 2019, p. 21.

96 SA Power Networks, *2020–25 regulatory proposal – Supporting document 5.12 - BIS Oxford Economics – Gross customer connections expenditure forecasts*, November 2018, p. 1.

97 SA Power Networks, *2020–25 regulatory proposal – Supporting document 5.12: BIS Oxford Economics – Gross customer connections expenditure forecasts*, November 2018, pp. 28-31.

98 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, pp. 88-90.

not remain at current levels. South Australian Government building approvals peaked in 2017–18 (consistent with BISOE's data), but returned to 2015–2017 levels based on most recent data for 2019.

- It observed an increase in 'Non-residential Commencements' and an increase in major customer connections capex, however it did not observe any relationship between 'Engineering Construction Work' and major customer connections capex.
- On proposed connections for real estate developments, EMCa considers that the proposed capex and capital contributions should be reduced to reflect lower After Diversity Maximum Demand (ADMD). SA Power Networks' own evidence indicates that based on recent transformer load tests, it has reduced ADMD by 1 or 2 kVA.[99] Further, SA Power Networks' own documentation demonstrates that connection costs reduce significantly as ADMD reduces.[100]
- There are material data discrepancies between SA Power Networks' reset RIN and regulatory proposal, which indicated gross connections forecasts up to $114 million higher than BISOE's figure. SA Power Networks provided a reconciliation of the forecasts in an information request response, and some adjustments are understood.[101] However, some adjustments included in the reconciliation have not been explained, including a 'Reg adjustment' of $47 million. In EMCa's view these adjustments made to BISOE's forecasts are not justified. EMCa has also highlighted that the opposite problem is evident for net connections, where the BISOE figures are higher than the figures reported in the RIN.

In EMCa's view, SA Power Networks' connections capex forecast for 2020–25 is above what it considers to be a reasonable, prudent and efficient level.[102]

We had regard to EMCa's list of concerns and identified a further issue with the data discrepancies in SA Power Networks' modelling. It applied a 19 per cent adjustment for overheads in converting the BISOE forecast to the figures included in its regulatory proposal. This adjustment is inconsistent with an overheads removal adjustment of 4.8 per cent that SA Power Networks applies in its capex model to convert the forecast expenditure from costs inclusive of overheads into direct costs.[103] This discrepancy in overheads adjustments also indicates that the connections capex forecast appears to be overstated.

We consider the current period connections capex reasonably reflects prudent and efficient expenditure and is therefore the basis of our substitute forecast. We have

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99 SA Power Networks, *Information request 39*, 31 June 2019, p. 38.

100 SA Power Networks, *2020–25 regulatory proposal – Supporting document 5.1 - Future network strategy*, November 2017, p. 68.

101 SA Power Networks explained that a significant reason for the difference is the inclusion of gifted assets in the higher forecasts, which are not included in the BISOE forecast. Gifted assets are cancelled out in net connections capex through a capital contribution of equal value to the gross expenditure.

102 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, pp. 89–90.

103 SA Power Networks, *Information request 8 – Capex program list*, 20 March 2019.

adopted the five-year period (2015–20) as our substitute estimate, which includes estimates for 2018–19 and 2019–20, as the final two years are in line with the 2017–18 actual expenditure. In addition, we have accepted SA Power Networks' capital contributions,[104] as SA Power Networks demonstrated that its contributions' forecast is in line with its actual expenditure.

A.5 Replacement expenditure

Replacement capital expenditure (repex) must be set at a level that allows a distributor to meet the capex objectives. Replacement can occur for a variety of reasons, including when:

- an asset fails while in service or presents a real risk of imminent failure
- a condition assessment of the asset determines that it is likely to fail soon (or degrade in performance, such that it does not meet its service requirement) and replacement is the most economic option[105]
- the asset does not meet the relevant jurisdictional safety regulations, and can no longer be safely operated on the network
- the risk of using the asset exceeds the benefit of continuing to operate it.

The majority of network assets will remain in efficient use for far longer than a single regulatory control period (many network assets have economic lives of 50 years or more). As a result, a distributor will only need to replace a portion of its network assets in each regulatory control period. Our assessment of repex seeks to establish the proportion of SA Power Networks' assets that will likely require replacement over the 2020–25 regulatory control period and the associated capital expenditure.

A.5.1 Draft decision

SA Power Networks has not demonstrated that its forecast repex of $637.2 million is prudent and efficient. We have determined a substitute estimate of $508.5 million, which is $128.6 million (20 per cent) lower than SA Power Networks’ forecast. We are satisfied that our substitute estimate meets the capex criteria.

The substitute estimate is above SA Power Networks’ actual spend over the last five years, namely the 2013–18 regulatory years. SA Power Networks has not justified its claimed increased risk and the step up in repex required to mitigate this risk. Our decision has been driven by the following observations:

- Overstated risk in SA Power Networks' condition-based modelling and therefore forecast repex required to mitigate this risk

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[104] The minor difference between the capital contributions included in our substitute estimate and SA Power Networks' capex forecast is due to modelling adjustments, which is discussed in section A.1.2.

[105] A condition assessment may relate to assessment of a single asset or a population of similar assets. High value/low volume assets are more likely to be monitored on an individual basis, while low value/high volume assets are more likely to be considered from an asset category wide perspective.

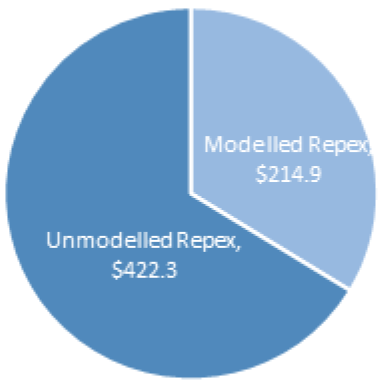
- Insufficient evidence to support the inclusion of last two years of the current period (2018–19 and 2019–20), where the historical trend is used to derive forecast repex. Estimates for the last two years of the current regulatory control period represent a significant step up (approximately 62.0 per cent higher than the average of 2013–18 regulatory years)[106]
- SA Power Networks' modelled repex is $13.0 million above the repex modelling threshold.[107] The repex model indicates that SA Power Networks' forecast for underground cables, transformers and switchgear are higher than predicted by the model. As such, we have targeted those asset groups in our bottom-up review.

A.5.2 SA Power Networks' proposal

SA Power Networks has proposed a repex forecast of $637.2 million for the 2020–25 regulatory control period, which makes up 37.1 per cent of its total capex forecast. SA Power Networks has submitted that this level of repex expenditure is necessary to:

- maintain an acceptable level of distribution system safety and reliability by addressing identified defects in, and the degradation of, their ageing network assets
- meet their jurisdictional service standards and to comply with their other regulatory obligations and requirements. Figure 5.4 outlines how we have classified SA Power Networks' proposal for each of these two repex components.

Figure 5.4 SA Power Networks' repex ($ million, 2019–20)[108]



Source: AER analysis.

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106 This includes the years 2013–14 to 2017–18.

107 The repex model results set a threshold against which we compare the distributor's forecast repex. Our current approach sets the repex model threshold equal to the higher of the 'cost scenario' and the 'lives scenario'. This approach considers the inherent interrelationship between the unit cost and expected replacement life of network assets. See, AER, *Draft decision - SA Power Networks distribution determination 2020–25 - AER capital expenditure assessment outline*, October 2019.

108 We have excluded Stobie poles from modelled repex, due to their unique nature, this is discussed in Appendix C.

SA Power Networks has applied a mix of forecasting methods to justify its repex forecast – CBRM, historical trend and bottom up estimates for a sample of projects. It also ran the AER's repex model and sanity checked its forecast against the repex modelling threshold.

A.5.3 Reasons for draft decision

We have applied several techniques to assess SA Power Networks' proposed repex forecast as well as considering stakeholder submissions. These techniques include:

- a review of SA Power Networks' repex forecasting methodology
- trend analysis
- repex modelling
- top-down and bottom-up assessments
- a governance review.

SA Power Networks' repex forecasting methodology

To forecast repex, SA Power Networks either applied a historical repex trend or used the outcomes of the CBRM tool. SA Power Networks also ran the repex model and sanity checked its forecast against the repex modelling threshold, albeit with different assumptions.

The outcomes of the CBRM is a key determinant of SA Power Networks' forecast repex underpinning 44 per cent of the forecast. It has been used to forecast replacements for poles, substation transformers, circuit breakers and protection relays. While we have not been able to critically review the workings of the model due to the proprietary restrictions attached to the model, we acknowledge the usefulness of the CBRM as a forecasting tool. It comprehensively accounts for all individual assets, including their characteristics, environmental factors and then provides a risk analysis at the aggregate (population) level. Similarly, the SA Government's submission noted that the Office of the Technical Regulator supports the new condition-based risk management model, but added that it is difficult for stakeholders to assess the validity of capital expenditure requested for this purpose.[109]

As already raised with SA Power Networks, we have concerns with the assumptions, inputs and how the outputs were used to inform the forecast:[110]

- The CBRM assumes that risk levels need to be maintained at 2018 or 2019 levels, however, SA Power Networks has not demonstrated why the 2018 or 2019 risk levels are reasonable or, similarly, why a higher or lower level of risk is not acceptable.

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109 South Australian Government, *Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2020–25*, 15 May 2019, p.1.

110 SA Power Networks, *Letter to the AER - Forecast Replacement Capital Expenditure*, 12 August 2019.

- The CBRM overstates risk and therefore the expenditure required to reduce this risk. For example, to forecast poles, SA Power Networks calculates the annual deterioration of this asset population as measured at the end of regulatory control period (2025), while assuming that there is no intervention during the period, apart from the usual unplanned interventions (e.g. cars hitting poles). This modelling characteristic is likely to overstate risk, as SA Power Networks is likely to be replacing these poles year-on-year and reducing the risk, which is not contemplated by the model.
- CBRM's resultant risk and consequence values are likely to be overstated. Despite the inability to review how the values were incorporated in the modelling, we as well as EMCa observed that these values are more closely aligned with a maximum consequence value, rather than average consequence values.[111] As such, where maximum consequence values are applied, they should be moderated to reflect that a maximum consequence does not occur for every occurrence of that consequence. Without the application of moderation factors, which we have not found any evidence for, we would view that the resulting risk values are likely to be inflated.
- Testing of the prudency and efficiency of proposed capex works appears to be undertaken at the annual budgeting process. This occurs after SA Power Networks has its capex allowance confirmed. As observed by EMCa, this distinct disconnect between the forecasts from the CBRM which are submitted in the regulatory proposal and then the estimates SA Power Networks actually uses in its actual budgeting process, reduces confidence that the proposed capex forecast is prudent and efficient.
- We observe SA Power Networks relied solely on the CBRM to forecast its required expenditure, for example for poles, without relying on other forecasting approaches such as failure rate analysis to test its forecast. The prudency and efficiency of the forecast should be tested with other forecasting tools. This is particularly the case where we could not review the workings within the CBRM, due to its propriety nature, and the material contribution that CBRM forecasted repex makes of the total repex forecast.

Trend analysis

Figure 5.5 highlights that SA Power Networks is forecasting a significant increase in repex in 2020–25, when compared to its long-term average. It is also forecasting an increase in asset replacement volumes over the same period, as highlighted below throughout the 'modelled repex' and 'unmodelled repex' sections.

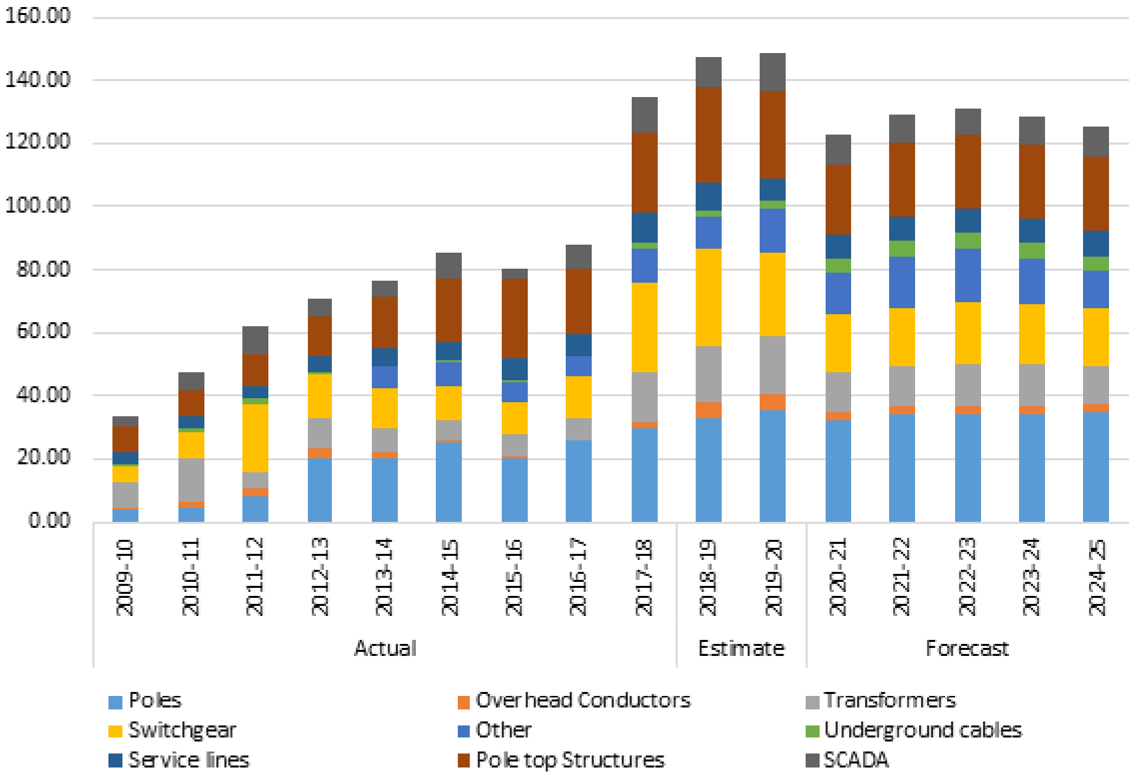
During our review, we have observed that where SA Power Networks has applied historical trend as the primary basis for its forecast, high estimates for the last two

111 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 100.

years of the current period were incorporated, which inflates the historical amount. Figure 5.5 shows how the estimates for 2018–19 and 19–20 compare to its long-term trend. The estimates represent a significant step up compared to the 2009–17 regulatory years. SA Power Networks explained that the reason for the step-up is due to its defects' find-rate and a higher network risk.[112] EMC has observed that an increase in inspections are likely to identify a higher volume of defects, however, that does not indicate that network risk is increasing. EMCa observed that SA Power Networks' use of a value-based approach to replacement suggests that:

- the current level of expenditure is likely to constrain the level of risk
- the backlog of defects appear to be independent of SA Power Networks' own assessment of risk
- SA Power Networks will likely to continue to undertake work based on the highest value per repex, which may not lower the backlog of defects.[113]

Figure 5.5 SA Power Networks' repex by asset group 2009–10 to 2024–25 ($ million, 2019–20)



Source: SA Power Networks' regulatory information notices - AER analysis.

112 SA Power Networks, *2020–25 Regulatory Proposal – Supporting documentation 5.9 – Repex Overview*, January 2019, public, p. 30.

113 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 99.

In addition, the SA Government's submission recognised that repex makes up a significant portion of capex, and that the forecast is approximately 12.0 per cent higher of the 2015–20 allowance of $89.0 million. As such, the SA Government encouraged us to fully assess whether the proposed asset replacement expenditure is fully justified and to consider whether it is reasonable to expect that SA Power Networks can implement an asset replacement program of this size in time where the sector is undergoing an energy transition.[114]

Modelled versus unmodelled repex

To assess SA Power Networks' repex forecast for the 2020–25 regulatory control period, we used the repex model to test 24 per cent of SA Power Networks' total repex forecast. Table 5.6 below shows what assets were considered modelled and unmodelled when assessing SA Power Networks' forecast repex.

Table 5.6 Breakdown of repex into modelled and unmodelled categories

Modelled Repex	Underground cables
	Transformers
	Switchgear - modelled
	Service lines
	Overhead conductors
Unmodelled repex	Poles
	Pole top structures
	SCADA and protection assets
	Other repex
	Switchgear unmodelled – 66 kV Northfield Gas Insulated Switchboard

Poles are usually a modelled asset group, however, we have excluded poles from modelled repex due to the uniqueness of SA Power Networks' Stobie poles.[115] This is consistent previous determinations, where we have excluded unique assets, such as fibreglass poles and 132 kV underground cables, as those assets cannot be

[114] South Australian Government, *SA Power Network's Regulatory Proposal for 2020–25*, public, 15 May 2019, p. 1.

[115] Stobie poles are made out of concrete and steel. SA Power Networks has chosen to report them as a separate category in its Regulatory Information Notices.

benchmarked, on unit costs or expected asset replacement lives to other distributors.[116]

In May 2019, we provided SA Power Networks' preliminary modelling results, which detailed the classification between modelled and unmodelled repex as described in Table 5.6 above. In response to the results, SA Power Networks raised its concerns with the classification. SA Power disagreed with three of our assumptions,[117] namely:

- the exclusion of poles from modelled repex
- the modelling of 66 kV Gas Insulated Switchboard
- the blending of replacement and refurbishment for transformers and switchgear.

Our response to SA Power Networks' letter is discussed in detail in Appendix C of this attachment.

Unmodelled repex

Unmodelled repex makes up approximately 66.3 per cent of SA Power Networks' forecast repex. SA Power Networks' forecast an increase in unmodelled repex which prompted us to review the following asset groups, namely poles, pole top structures, its Northfield Gas Insulated Switchgear (GIS) program and other repex.

Poles

Poles makes up 26.6 per cent of SA Power Networks' proposed repex forecast. The poles forecast is $169.6 million and is a 39.8 per cent increase from its actuals over the 2013–18 regulatory years. Figure 5.6 below shows the long-term trend for poles repex.

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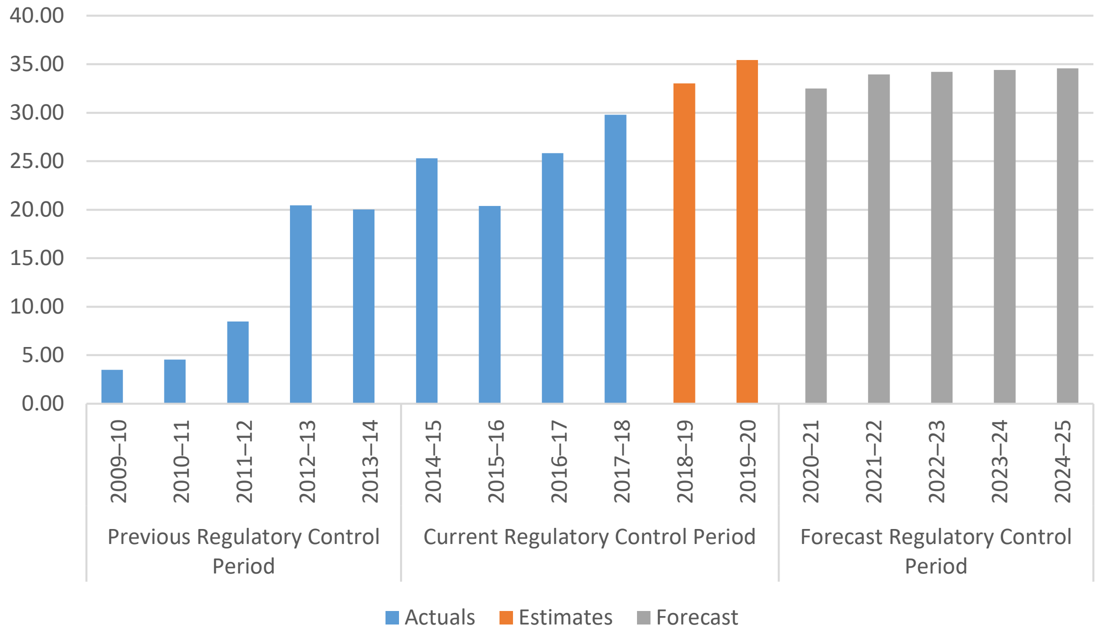
[116] AER, *Draft Decision – Evoenergy Distribution Determination 2019-24 – attachment 5 – Capital Expenditure*, September 2018, p.54. AER, *Draft Decision - Ausgrid Distribution Determination 2019-24 – attachment 5 - Capital Expenditure*, September 2018.

[117] SA Power Networks, *Letter to the AER - AER preliminary repex modelling results for SA Power Networks*, 21 June 2019.

Figure 5.6 SA Power Networks' poles repex from 2009–10 to 2024–25 ($ million, 2019–20)



Source: SA Power Networks' RIN, AER analysis.

To support its poles repex, SA Power Networks noted an increase in the number of outstanding defects. SA Power Networks used the CBRM model to forecast poles repex. In addition to the overall CBRM concerns discussed above, EMCa raised other concerns with SA Power Networks’ poles repex over the forecast period:

- While SA Power Networks’ claimed that all of its poles expenditure was derived using CBRM, it has also proposed a further $23.2 million for rectifying line clearances' defects within its poles repex.[118] This line clearance program was not described in its regulatory proposal. EMCa also observed that the expenditure is not required to meet legislative obligations. We agree with EMCa that the proposed additional expenditure would appear to undermine the reliability of the CBRM model as the primary forecasting method.[119]
- Inconsistency with SA Power Networks’ claims about a trend in pole failure rates. SA Power Networks state in its proposal that the pole failure rates are increasing, however, SA Power Networks’ own analysis also shows that the historical number of pole failures has remained relatively stable since 2010–2011, aside from the

[118] SA Power Networks, *Information Request 44 – Capex program list*, 3 June 2019.

[119] Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p.106.

relatively high number of failures in 2013–2014 and 2016–2017,[120] which SA Power Networks state is more likely the result of severe storms.

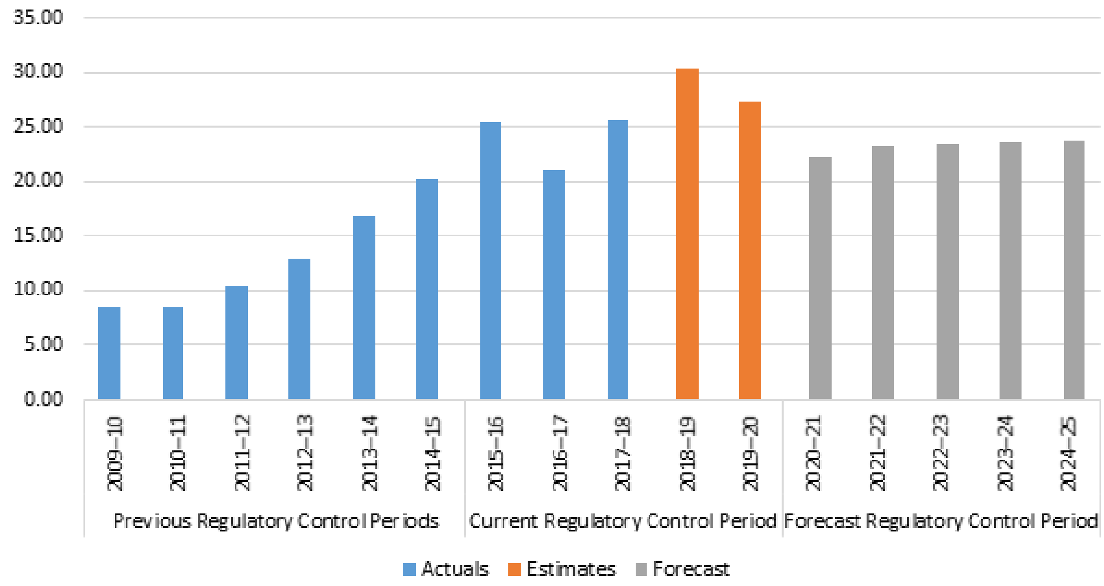
- SA Power Networks has not provided adequate sensitivity analysis to demonstrate no bias in critical inputs to the CBRM model.[121]
- SA Power Networks has not provided sufficient information to conclude that the elevated level of completed defects in calendar year 2017 is representative of an increasing trend that would indicate an increasing level of network risk.[122]

SA Power Networks has not demonstrated a need to increase its poles repex in the 2020–25 over and beyond its actual current levels. Therefore, we have relied on SA Power Networks' historical expenditure over the last five years, 2013–18 regulatory years, as the basis for our substitute estimate.

Poles top structures

SA Power Networks is forecasting $116.3 million for its pole top structures repex, which is a 6.6 per cent increase from its actuals over the 2013–18 regulatory years. Figure 5.7 below shows the long-term trend for pole top structures repex.

Figure 5.7 SA Power Networks' pole top structures repex 2009–10 to 2024–25 ($ million, 2019–20)



Source: SA Power Networks' RIN, AER analysis.

[120] Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p.107.

[121] Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p.108.

[122] Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p.108.

SA Power Networks based its forecast pole top structure replacement program on a continued flat investment profile from the 2015–20 regulatory control period, which includes the high estimates in the last two years of the current regulatory control period.[123]

We have observed that overhead switchgear, a category within its pole top structures group, is forecast to increase by 32 per cent over 2020–25, when compared to the 2013–18 regulatory years.[124] SA Power Networks stated that increase in repex corresponds with an increase in inspections across the network.[125] SA Power Networks has not demonstrated that an increase in pole top structure renewal expenditure is required to address declining network performance or the increasing level of risk in its pole top structure population. SA Power Networks submits that pole top structures defects are increasing, however, we agree with EMCa that the increasing number of identified defects is not, by itself, an indication of an increasing level of risk on the network. When EMCa reviewed the level of completed defects, as an indicator of the actual risk observed in the network, EMCa observed that the level of work completed in the current regulatory control period does not appear congruent with the basis for the forecast in the next regulatory control period.[126]

Based on the information above and taking into consideration EMCa's analysis, SA Power Networks has not demonstrated that the step-up in its forecast pole top structure repex is prudent and efficient. Our substitute estimate is based on the historical expenditure for overhead switchgear replacement over the 2013–18 regulatory years.

Unmodelled Switchgear – Northfield GIS

SA Power Networks included a capex forecast of $11.2 million to replace its 66kV Gas Insulated Switchboard (GIS) in Northfield. This figure represents approximately a third of the total value of the project, which is expected to be staged over multiple regulatory control periods, of total value $29.9 million ($2019–20, including overheads).

The GIS replacement is driven by its deteriorating condition. SA Power Networks commissioned GHD Advisory (GHD) to investigate its present state.[127]

We have a number of concerns with this project:

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123 SA Power Networks, *Information Request 17 – EMCa governance and repex*, 12 April 2019, p. 5.

124 SA Power Networks, *Information Request 44 - Capex Program List - RepexMapping*, 12 June 2019.

125 SA Power Networks, *2020–25 regulatory proposal - Overhead Switchgear Line Fuse Bases – Asset Plan 3.1.07*, p. 7.

126 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 114.

127 SA Power Networks, *Information Request 55 - Question 1 - GHD - Northfield 66kV GIS Condition Assessment Final Report*, 26 June 2019.

- GHD indicated that short term interventions are likely to improve the likelihood of the existing GIS achieving its designed 'service life', and stated that this can be reasonably achieved following intervention.[128]
- SA Power Networks' preferred option of complete replacement with an Air Insulated Switchgear (AIS) assumes that the GIS will last till 2030 with short term interventions. SA Power Networks expects that it will not require the AIS until two regulatory control periods away, when the existing GIS reaches the end of its life. This implies that the timing is not prudent.
- The logic in SA Power Networks' 'do-nothing' option contradicts its preferred option. The 'do-nothing' option would be subject to the same interventions during the 2020–25 regulatory control period; however, it was deemed to be unacceptable as there was an assumption that the GIS would fail in the current regulatory control period. Based on this SA Power Networks is overstating the risk in its 'do-nothing' option.[129]
- SA Power Networks has demonstrated that it is complying with reporting schemes and South Australian and Commonwealth legislation with regard to the release of sulphur hexafluoride gas, which is one of the risks associated with the condition of the GIS.[130] In response to an information request, SA Power Networks submitted that it has procedures in place to manage the risk of release, as such SA Power Networks has not satisfied us that the benefits of replacement exceeds the risk cost.[131]

Based on the information before us, SA Power Networks did not establish that its proposed GIS replacement project is prudent. As such we have not included this project as part of the substitute capex estimate. We encourage SA Power Networks' to consider the concerns stated above, when preparing its revised proposal.

Unmodelled – Other repex

SA Power Networks submitted that other repex includes items that are ancillary to the operation of its substations.[132] SA Power Networks is forecasting \$62.7 million for its other repex. Figure 5.8 below shows the long-term trend for other repex.

128 SA Power Networks, *Information Request 55 – Repex Northfield GIS*, 26 June 2019, p.28.

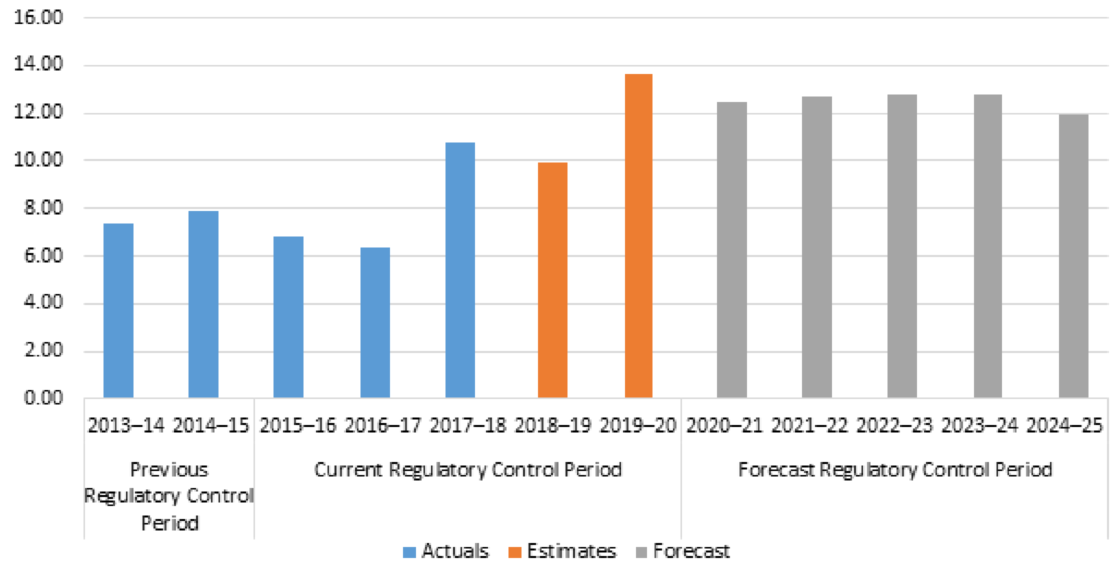
129 SA Power Networks, *Information Request 52 – Q2a – Northfield NPV Option Analysis*, 18 June 2019.

130 SA Power Networks, *Information Request 55 – Q2 – EMS 5.16 – WI - SF6 Gas Management*, 29 June 2019.

131 SA Power Networks, *Information Request 55 – Q2 – EMS 5.16 – WI - SF6 Gas Management*, 29 June 2019.

132 These items may be found within or support the operation of a substation such as substation spares, substation civil or buildings and ancillary equipment such as fences, gates and signs.

Figure 5.8 SA Power Networks' other repex 2013–14 to 2024–25 ($ million, 2019–20)



Source: SA Power Networks' RIN, AER analysis.

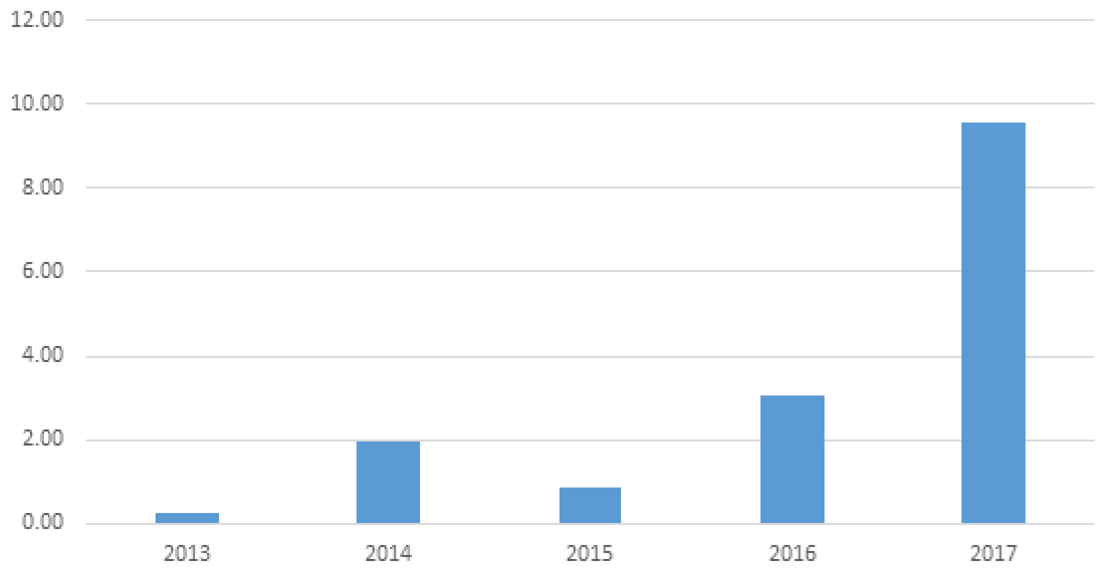
We have identified a number of concerns with two projects that make up 42 per cent of this asset group, namely the CBD ducts and manholes project as well as the Pipework substation replacement project. Each are discussed in turn below.

CBD ducts and manholes

SA Power Networks is proposing $13.2 million for its CBD ducts and manholes repex over the forecast regulatory control period.[133] SA Power Networks' historical expenditure, shown in Figure 5.9 demonstrates the non-recurrent nature of this investment, which is largely driven by its $9.6 million repex expenditure in 2017.

133 SA Power Networks noted that ducts are used throughout the distribution network to enable the installation and replacements of underground cables. These ducts are grouped together and connected by manholes typically used for joining high voltage and low voltage cables. See, SA Power Networks, *Information request 1 - CBD asset management plan 2.1.07*, p. 18.

Figure 5.9 SA Power Networks' historical CBD ducts and manhole repex 2013–17 ($ million, 2019–20)



Source: SA Power Networks' response to Information Request 58, AER analysis.

The North Terrace duct replacement project, which is forecast at $10.0 million, is a subset of the CBD ducts and manholes repex.[134] SA Power Networks submits that this project is required to allow for the prompt installation of new cables following a cable fault, without the need for extensive reactive civil works that would be otherwise required in the CBD.[135]

We have a number of concerns with this program:

- Despite SA Power Networks' statement that this is largely reliability driven, SA Power Networks has not undertaken any cost-benefit analysis, which would incorporate the value of unserved energy or value of customer reliability to justify this project.
- In its asset management plan, SA Power Networks acknowledges the quantum of duct replacements needed. The asset management plan states that any of the proposed works are staged subject to budget availability, which shows that there is a lack of robust testing of its capex forecasts during the revenue proposal stage. This implies that either the entire or part of $13.2 million is likely to be staged into the next regulatory control period, once SA Power Networks conducts its detailed option analysis, during the annual budget process.

[134] SA Power Networks, *CBD asset management plan 2.1.07*, public, p. 43.

[135] SA Power Networks, *Information Request 58 – Repex forecast and repex-opex step-change*, p. 5.

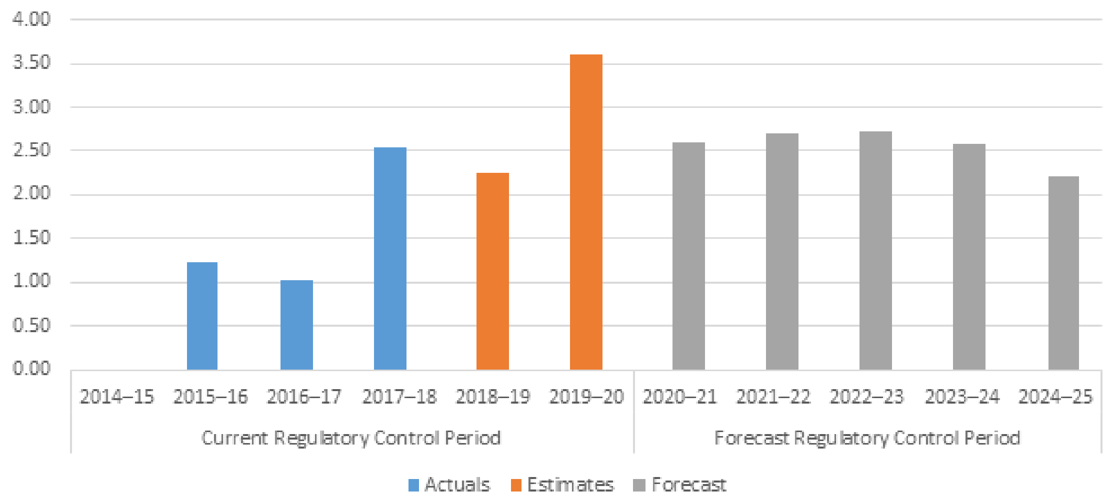
- SA Power Networks has previously proposed the North Terrace duct replacement in its 2015–20 regulatory proposal,[136] which we have accepted as part of its current capex allowance. SA Power Networks has then subsequently deferred the project in its entirety.

SA Power Networks has not established that the North Terrace duct replacement project is prudent. Therefore, we have not included the $10.0 million associated with the North Terrace Duct replacement project as part of our substitute estimate for capex.[137]

Pipework style switchyard replacement

SA Power Networks is proposing $13.2 million for its pipework style switchyards replacement project. Figure 5.10 demonstrates the trend between the actuals over the current regulatory control period, when compared to its forecast. The step-up in its forecast for pipework switchyards repex over the forecast period when compared to its annual average over the 2015–18 regulatory years is 38 per cent.

Figure 5.10 Pipework switchyards repex 2015–16 to 2024–25 ($ million, 2019–20)



Source: SA Power Networks' RIN, AER analysis.

[136] SA Power Networks, *2015–20 regulatory proposal - Supporting Documentation 2.1.07 – SA Power Networks CBD*, October 2014, p. 23.

[137] SA Power Networks, *2015–20 regulatory proposal - Supporting Documentation 2.1.07 – SA Power Networks CBD*, October 2014, p. 43.

SA Power Networks is proposing to replace its entire Category 1 substations over the 2018–25 regulatory years, which includes 23 sites.[138] We have a number of concerns with this project, including:

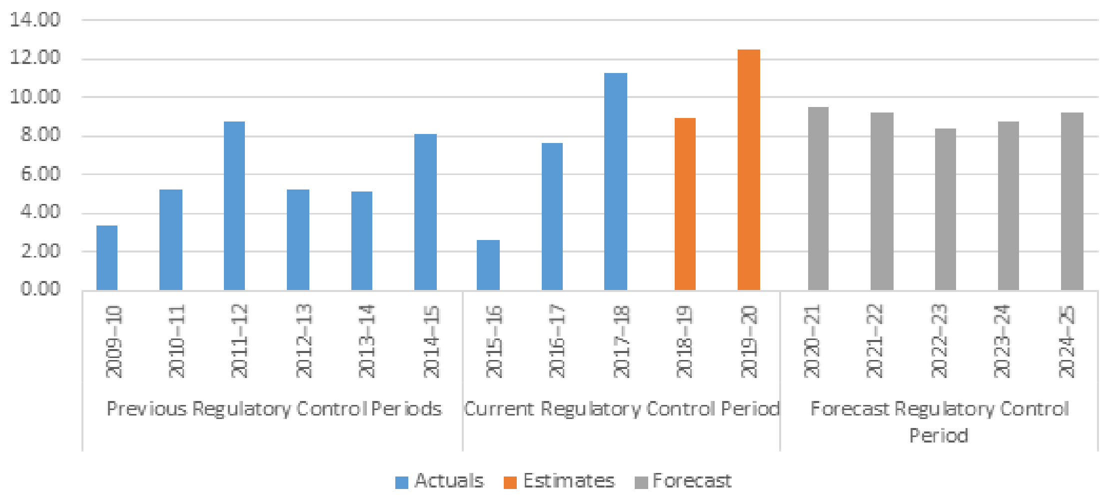
- Despite SA Power Networks undertaking an engineering review, to assess the criticality and priority of each substation relative to the others, SA Power Networks proposed to replace all of these Category 1 pipework style switchyards substations, even the ones that were ranked low on the priority list.[139]
- SA Power Networks has not undertaken any cost-benefit analysis, which would identify the likelihood of failure, the likelihood of consequence and the cost of consequence that would result from the failure of any of these substations, in order to justify the investment.

SA Power Networks has not justified the prudency or the efficiency of the step-up in repex that is associated with its pipework switchgear replacement. Our substitute estimate is based on SA Power Networks' annual average expenditure over the 2015–18 regulatory years.

SCADA and protection repex

SA Power Networks is forecasting $45.1 million for its SCADA and protection repex, which is a 29.5 per cent increase from its actuals over the 2013–18 regulatory years. Figure 5.11 below shows the long-term trend for SCADA and protection's repex.

Figure 5.11 SA Power Networks' SCADA and protection repex 2009–10 to 2024–25 ($ million, 2019–20)



Source: SA power Networks' RIN, AER analysis.

138 SA Power Networks, *Information Request 24 - Repex and Augex - Q11aiii Asset Plan 3.2.12 Substation Pipework Switchyard*, 9 May 2019.

139 SA Power Networks, *Information Request 24 - Repex and Augex - Q11aiii Asset Plan 3.2.12 Substation Pipework Switchyard*, 9 May 2019, p.26.

This asset group is largely made up of its protection relays replacement program, which is $15.6 million over the forecast regulatory control period. SA Power Networks also included $6.6 million of SCADA and protection repex associated with its Data Network and $3.1 million for Network Telecommunication Planning Labour Capitalisation. The remaining asset group relates to SA Power Networks' telecommunication assets, such as its optical fibre and microwave radio networks, as well as the structures that support telecommunication assets.[140]

SA Power Networks used a CBRM model to forecast repex for its protection relays. Consistent with our CBRM concerns above, SA Power Networks has not established its CBRM methodology provides an efficient level of expenditure, as it is likely to overstate risk and the expenditure required for protection relays.

As for SA Power Networks' forecast for Data Network project, SA Power Networks provided its asset management plan, which forecasts a deterministic number of replacements over the forecast period. SA Power Networks has not undertaken any failure rate analysis or cost benefit analysis that would justify the replacement of assets that supports the provision of its Data Network. For example, in its Data Network asset management plan, SA Power Networks states that 22 switches reach the end of their lifecycle in 2022, despite SA Power Networks' management strategy to replace on failure for this particular asset.[141] There was no consideration to actual failure rates over the period.

For the network telecommunication planning labour capitalisation, SA Power Networks noted that this project reflect the expenditure associated with capital works, which includes but is not limited to, project management, engineering and/or design of a network telecommunications solution.[142] SA Power Networks' capex program list states that this project forecast is based on its historical expenditure.[143] We requested the historical expenditure associated with the program, SA Power Networks provided the historical data over the 2013–18 regulatory years, which is 47 per cent below the forecast amount. There is no justification for the increase or what might be driving an increased expenditure over the forecast period.

Based on the above concerns, we do not consider that SA Power Networks has justified the increase in its forecast repex for SCADA and protection assets. As such, we have determined a substitute estimate which is consistent with SA Power Networks' historical expenditure for SCADA and protection repex over the 2013–18 regulatory years.

140 SA Power Networks, *Information Request 8 - Capex program list*, 20 March 2019.

141 SA Power Networks, *Information Request 058 – Q4 – Asset Plan 3.3.12 Data Network*, p. 11.

142 SA Power Networks, *Information Request 58 – Repex forecast and repex-opex step-change*, p. 3.

143 SA Power Networks, *Information Request 8 - Capex program list*, 20 March 2019.

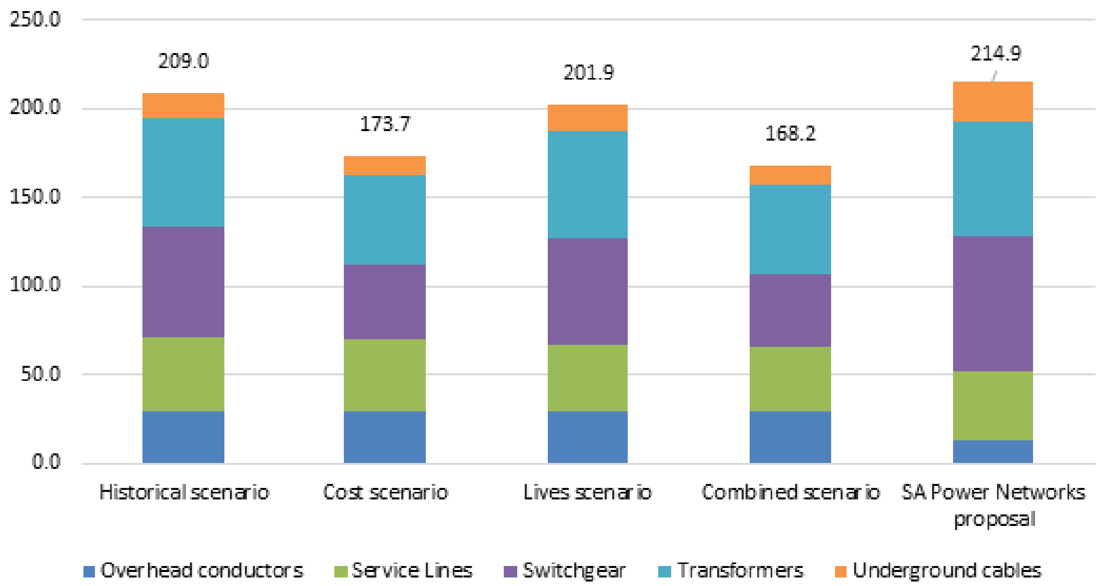
Modelled repex - Repex model analysis

SA Power Networks' proposal includes $214.9 million in modelled repex. SA Power Networks has not justified that its forecast is prudent and efficient. Consistent with 2019–24 determinations, we tested SA Power Networks' asset categories that could be modelled and compared its repex forecast against the following four scenarios:

- historical scenario – historical unit costs and calibrated expected replacement lives
- cost scenario – comparative unit costs and calibrated expected replacement lives
- lives scenario – historical unit costs and comparative expected replacement lives
- combined scenario – comparative unit costs and comparative expected replacement lives.

Figure 5.12 highlights SA Power Networks' proposed modelled repex compared with the four scenarios. The repex model threshold for SA Power Networks is the 'lives scenario'.[144] SA Power Networks' proposal of $214.9 million is $13.0 million higher (6.0 per cent) than the lives scenario and $41.2 million higher (23.7 per cent) than the cost scenario. This indicates that on average, SA Power Networks' repex forecast has higher unit costs and lower expected replacement lives than other distributors.

Figure 5.12 SA Power Networks' modelled repex forecast vs the four repex modelled scenarios



Source: AER analysis.

144 Our current approach sets the repex model threshold equal to the higher of the 'cost scenario' and the 'lives scenario'. This approach considers the inherent interrelationship between the unit cost and expected replacement life of network assets. See, AER, *Draft decision - SA Power Networks distribution determination 2020–25 - Repex model*, October 2019.

Notes: The 'historical scenario' uses historical unit costs and calibrated expected asset replacement lives. The 'cost scenario' uses comparative unit costs[145] and calibrated expected asset replacement lives. The 'lives scenario' uses historical unit costs and comparative expected asset replacement lives. The 'combined scenario' uses comparative unit costs and comparative expected asset replacement lives.

The repex model results highlight that SA Power Networks' proposal is higher than the model prediction for switchgear, transformers and underground cables. We did not use the repex model results deterministically, namely to come up with a substitute estimate, rather we used the results of the repex model to focus our review on these three asset groups as the model predicted a lower forecast than SA Power Networks' proposed. Our substitute estimate for modelled repex, based on a bottom-up and historical trend estimates, is $186.7 million. The substitute estimate is between the cost and lives scenario as shown in Figure 5.12, as such consistent with the repex model prediction. We discuss our bottom-up review and the basis for our substitute estimate for each of those asset groups in turn below.

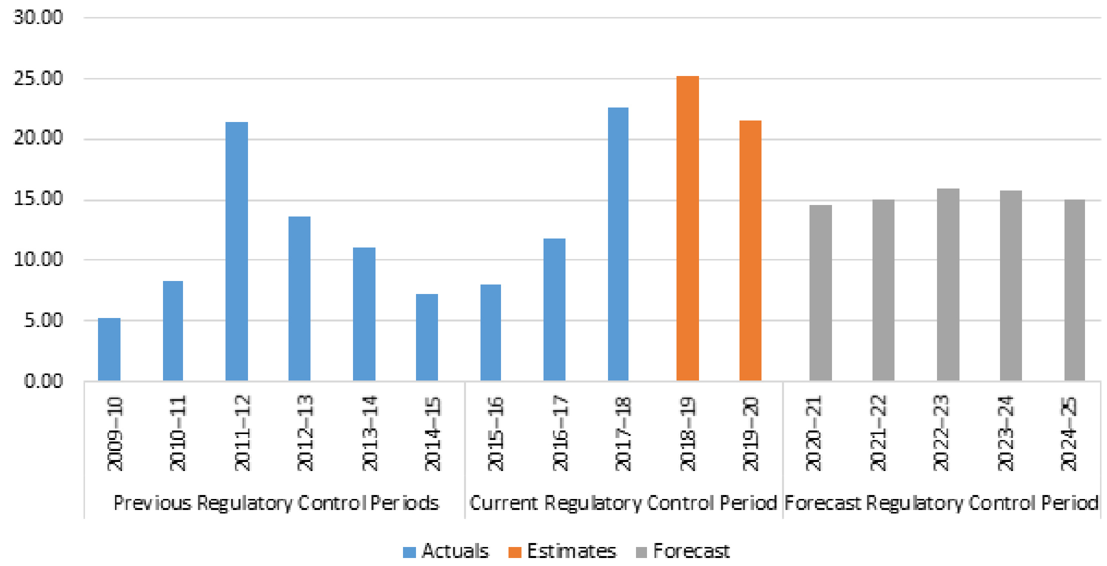
Modelled switchgear

SA Power Networks proposed $76.3 million for its modelled switchgear for the 2020–25 regulatory control period.[146] SA Power Networks' forecast is 26.6 per cent higher than predicted by its repex model of $60.3 million. It is also a step-up of 25 per cent from its actuals over 2013–18 regulatory years as shown in Figure 5.13.

[145] Comparative unit costs are the minimum of a distributor's historical unit costs, its forecast unit costs and the median unit costs across the NEM.

[146] SA Power Networks has excluded reclosers, sectionalisers and the Northfield Gas Insulated Switchgear from its modelled switchgear. We have assessed them as unmodelled repex through a cost-benefit and trend analysis perspective, without relying on the repex model.

Figure 5.13 SA Power Networks' modelled repex switchgear 2009–10 to 2024–25 ($ million, 2019–20)



Source: SA Power Networks' RIN, AER analysis.

Our bottom-up review has highlighted that the observed step-up is largely driven by SA Power Networks' circuit breaker replacement program. Circuit breakers repex is $54.3 million and is a step-up of 38 per cent from its 2013–18 regulatory years.

SA Power Networks has utilised the CBRM to forecast its circuit breakers repex.[147] In addition to our overall CBRM concerns, which are set out above. Our concerns with the application of the CBRM to forecast circuit breakers repex are magnified. Our review has identified that the risk is significantly overstated as it calculates risk levels at 2030, rather than 2025. To illustrate our concerns, our analysis has highlighted that risk levels at 2030 is 146 per cent higher than the risk levels at 2025, noting that the risk at 2025 is already overstated.[148]

SA Power Networks has not demonstrated that its proposed repex to mitigate circuit breakers risk is prudent and efficient. We have relied on SA Power Networks' historical expenditure for circuit breakers over 2013–18 regulatory years as the basis for our substitute estimate for this asset group.

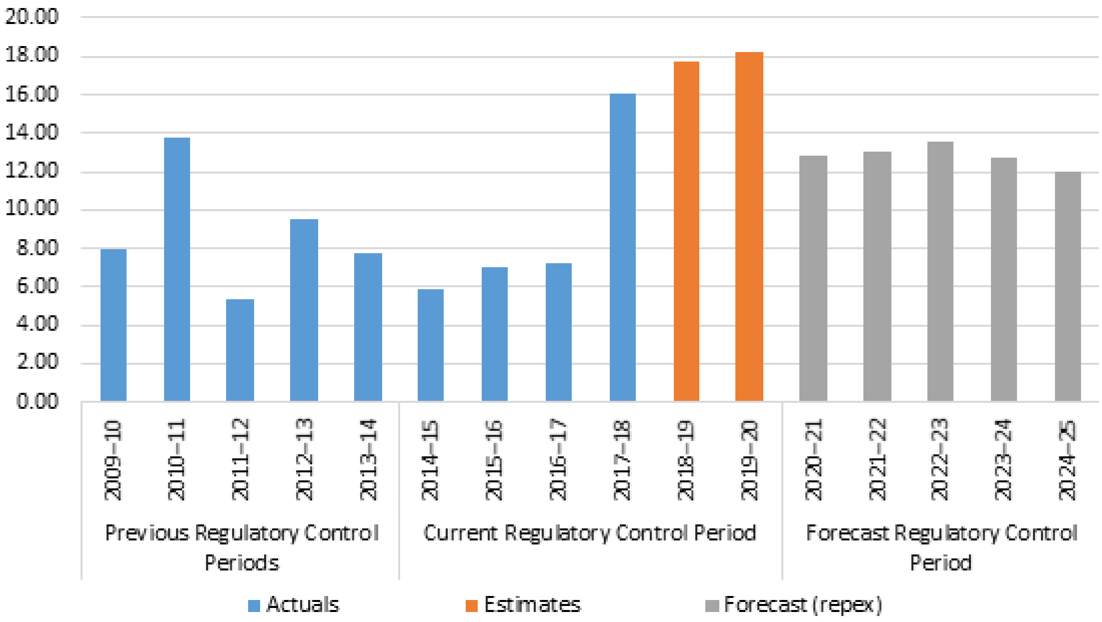
[147] AER, *Information Request 58*, 21 June 2019, p. 1.

[148] SA Power Networks, *Information Request 58 - Q3 - Substation CBRM Repex forecast*, 28 June 2019.

Transformers

SA Power Networks proposed $64.1 million for transformer repex over the forecast period.[149] SA Power Networks' forecast is 5.4 per cent higher than predicted by its repex model of $60.9 million. The 46 per cent step up in transformer repex from the 2013–18 regulatory years is shown in Figure 5.14.

Figure 5.14 SA Power Networks' modelled repex transformers 2009–10 to 2024–25 ($ million, 2019–20)



Source: SA Power Networks' RIN, AER analysis.

Table 5.7 below shows the program-level make up of SA Power Networks' transformers repex, the step-up in expenditure and the underlying forecasting methodology.

Table 5.7 Program level of make-up of transformer repex

Program	Historical versus Forecast	Forecasting methodology
Planned Distribution transformers	19 per cent	Targeted replacement of a type of transformer, with higher risk of catastrophic failure rate.
Unplanned Distribution transformers	12 per cent	10 year historical failure rate
Zone substation transformers	58 per cent	Condition Based Risk Modelling

Source: AER analysis.

149 SA Power Networks' proposed transformer repex includes the replacement of substation transformers and its planned and unplanned distribution transformers.

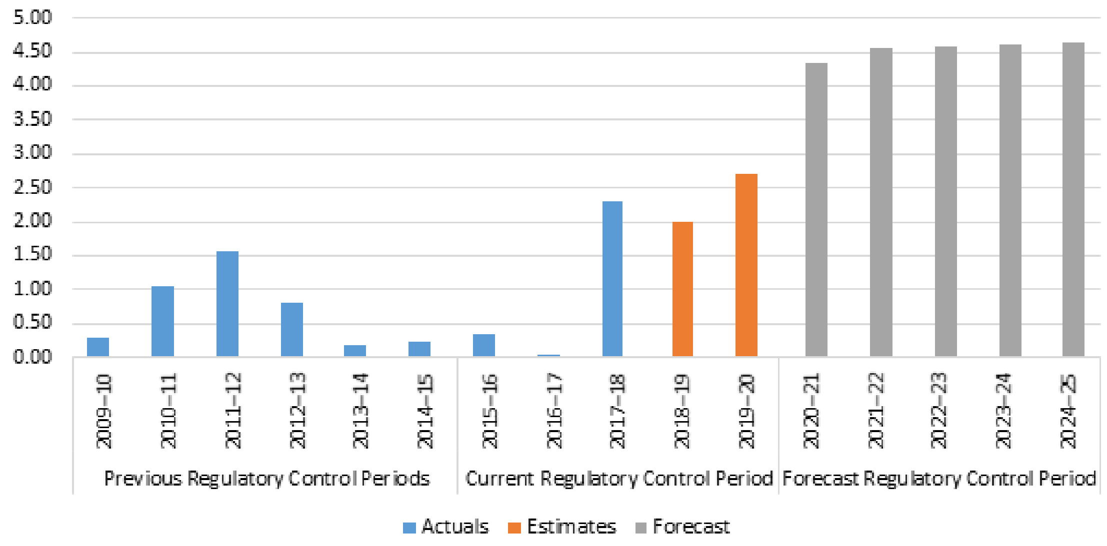
SA Power Networks is forecasting a step-up of 58.0 per cent for its zone substation transformers. SA Power Networks has utilised the CBRM to forecast its zone substation transformers repex.[150] In addition to our overall concerns with the CRBM discussed above, we have observed that, similar to the CBRM poles and switchgear model, the transformer CBRM model overstates risks. Our review has identified that the risk is overstated as it calculates risk levels at 2029, rather than 2025. To illustrate our concerns, our analysis has highlighted that risk levels at 2029 is 184 per cent higher than the risk levels at 2025, noting that the risk at 2025 is already overstated.

SA Power Networks' transformer CBRM methodology does not provide an efficient level of expenditure, therefore, we have relied on SA Power Networks' historical expenditure for substation transformers as the basis for our substitute estimate for transformers repex.

Underground cables

SA Power Networks proposed $22.7 million in repex for underground cables is a 636.5 per cent increase from 2013–18 regulatory years as shown in Figure 5.15 below.

Figure 5.15 SA Power Networks' modelled repex underground cables 2015–16 to 2024–25 ($ million, 2019–20)



Source: SA Power Networks' RIN - AER analysis.

Our bottom-up review has highlighted that the step-up is driven by the replacement of bare paper-insulated lead cables (PILC) in the CBD. SA Power Networks commissioned an engineering consultant to investigate the root cause of the higher than expected failures of these cables. The consultant concluded that the cables with

150 AER, *Information Request 44 - Repex and Augex*, 3 June 2019, p. 1.

the highest probability of failure share similar characteristics.[151] SA Power Networks points to the recent failures, which has had an impact on its reliability performance,[152] as a reason to phase out its entire 11 kV PILC cables, by replacing 7.6 km over 2020–26 with further replacement plans into the next regulatory control periods.[153] We have a number of concerns with SA Power Networks' methodology, in particular:

- A disconnect between SA Power Networks' forecast and the engineering advice as described in the engineering report. The report highlights that there are a total of 2.3 km of cables, which have the highest probability of failure. This is in contrast to its underground cable model, which aims to phase out the entire cable population within a certain timeframe.[154]
- The engineering report made no reference to any proactive cable replacement, rather a recommendation to monitor their condition.[155]
- As this replacement program is reliability driven, SA Power Networks has not provided any cost-benefit nor load at risk analysis to support its chosen volume of replacement.

SA Power Networks did not establish that its proposed repex forecast for underground cables is prudent and efficient. We have arrived at a substitute estimate, which allows SA Power Networks to replace the 2.3 km that were identified, by SA Power Networks' consultant, to have the highest likelihood of failure.

A.6 Information and Communications Technology (ICT)

Information and communications technology refers to all devices, applications and systems that support business operation. Expenditure for ICT is categorised broadly as either replacement of existing infrastructure (for reasons due to end of life, technical obsolescence, or added capability of the new system) or the acquisition of new assets for a business need.

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151 They are located within a specific clay region, which is subject to stresses from ground movements, high moisture and high corrosion potential, located beneath parklands and more readily influenced by daily weather and operating at high electrical loads. See SA Power Networks, *Information Request 24 – Repex and Augex – Q8a – PILC UG Cable Failure Phase 2 Final Report Issue 1*, p. 4.

152 SA Power Networks did not meet its CBD SAIFI and SAIDI targets for 2017. See SA Power Networks, *2020–25 Regulatory Proposal - Supporting Documentation 5.9 – Repex Overview*, January 2019, Public, p.67.

153 SA Power Networks, *Information Request 24 – Repex and Augex – Q8b_c – PILC Underground Cables – repex and augex*, 9 May 2019.

154 SA Power Networks, *Information Request 24 – Repex and Augex – Q8b_c – PILC Underground Cables – repex and augex*, 9 May 2019.

155 SA Power Networks, *Information Request 24 – Repex and Augex – Q8a – PILC UG Cable Failure Phase 2 Final Report Issue 1*, p. 32.

A.6.1 Draft decision

SA Power Networks has not justified that its $284.6 million for ICT forms part of a total capex forecast that reasonably reflects the capex criteria. SA Power Networks' forecast is $28 million lower than it estimates to spend in the current regulatory control period, however it is $33.1 million above its actual spend over the 2013–18 regulatory years. We have included an amount of $196.8 million for ICT capex in our substitute estimate, a 31 per cent reduction to SA Power Networks' forecast, which is shown in Table 5.8.

Table 5.8 Draft decision on SA Power Networks' forecast ICT capex ($ million, 2019–20)

Category	Proposal	Position	Difference
Recurrent ICT	**149.1**	**149.1**	**-**
Non-Recurrent ICT	**135.5**	**53.8**	**-81.7**
Asset and Works Management	*44.9*	*0.0*	*-44.9*
Billing/CRM Replacement	*27.4*	*27.4*	*-*
SAP S4 Upgrade	*26.9*	*0.0*	*-26.9*
Geographic Information System Consolidation	*15.0*	*15.0*	*-*
5 Minute Rule Change	*8.3*	*8.3*	*-*
RingFencing	*4.0*	*0.0*	*-4.0*
Worker Safety - Fatigue Management	*5.8*	*0.0*	*-5.8*
Network Protection System (PSS) Replacement	*3.1*	*3.1*	*-*
Total ICT	**284.6**	**202.9**	**-81.7**
Modelling Adjustment	*-*	*-6.1*	*-6.1*
Draft Decision on Total ICT capex	**284.6**	**196.8**	**-87.7**

Sources: SA Power Networks, *2020–25 Regulatory Proposal - Supporting Documentation 5.32 - IT Investment Plan 2020–25* and AER analysis.

A.6.2 SA Power Networks' proposal

SA Power Networks' recurrent ICT capex forecast of $149.1 million is comprised of the following programs:

- Client device refresh (age based replacement of laptops, desktops, etc.)
- Business Applications (lifecycle based investment patches and upgrades to the applications portfolio)
- IT Infrastructure replacement (lifecycle based investment in infrastructure)
- IT Management, Risk and Governance
- Cyber Security.

SA Power Networks' non-recurrent ICT capex forecast is comprised of eight programs totalling $135.5 million, which have the objectives of increasing efficiency, maintaining service standards and meeting compliance requirements.

A.6.3 Reasons for draft decision

In coming to our view, we have had regard to all the information before us, including EMCa's independent review and stakeholder submissions. Many submissions asked us to look closely at SA Power Networks' ICT capex proposal and raised concerns or questions, including from the CCP14[156] and the SA Government.[157] The submissions noted that:

- SA Power Networks could have provided more detail or justification for its forecast
- the proposal was high relative to other networks
- opex benefits appeared relatively low
- there is no evidence of the usual 'cycle' of renewal and higher investment (as is occurring in the current period) followed by a period of maintenance and lower investment, instead continued high investment.[158]

Consistent with the approach outlined in our ICT expenditure assessment guideline consultation paper,[159] we have assessed recurrent ICT capex separately to non-recurrent ICT capex. We outline our assessment of each category of ICT capex in turn below.

Recurrent ICT capex

We have assessed this aspect of the forecast primarily through a top-down assessment. This is because historical costs are a likely indicator of future costs for this ICT capex category given the nature of these investments.

In the ICT expenditure consultation paper, we indicated that we would also have regard to benchmarking analysis of recurrent ICT total expenditure (totex) to assess recurrent ICT capex forecast. However, due to the absence of consistent data across

156 CCP, *Advice to the AER on the SA Power Networks 2020–25 Regulatory Proposal,* 16 May 2019, p. 46.

157 SA Government, *Government of South Australia Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2020–25,* 15 May 2019, p. 2.

158 Business SA, *Business SA submission to AER on SA Power Networks Regulatory Proposal,* May 2019 pp. 6-7; SACOSS, *SACOSS submission in response to AER Issues Paper on the SA Power Networks' electricity determination 2020–25,* 10 May 2019 pp. 10-11; CCP, *Advice to the AER on the SA Power Networks 2020–25 Regulatory Proposal,* 16 May 2019, p. 46; SA Government, *Government of South Australia Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2020–25,* 15 May 2019, p. 2; South Australian Wine Industry, *Submission in response to the Issue Paper on SA Power Networks' Regulatory Proposal for 2020–25,* 15 May 2019, p.4; Central Irrigation Trust, *CIT Submission to SA Power Networks Regulatory Proposal (2020 – 2025)*, 15 April 2019, p. 1.

159 AER, *ICT Expenditure Assessment Review,* 8 May 2019, see: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/ict-expenditure-assessment-review.

all businesses in the NEM, we have not undertaken benchmarking analysis in this decision. We expect to apply benchmarking analysis in the 2025–2030 determination.

We asked EMCa to undertake a bottom-up review of the recurrent ICT capex forecast. We have had regard to EMCa's findings in forming our position on the overall recurrent ICT capex forecast.

Top-down Assessment

Given the nature of these investments, historical costs are a likely indicator of future costs for this category of ICT capex. SA Power Networks provided historical expenditure for each recurrent ICT program,[160] which shows that SA Power Networks' total forecast expenditure is 10.8 per cent lower than current period expenditure for these programs. From a top-down perspective, SA Power Networks' recurrent ICT capex appears to be a reasonable forecast of the prudent costs for this category of capex.

EMCa's advice

While we acknowledge our top-down results, we have also had regard to EMCa's advice. EMCa's review identified that SA Power Networks' forecast is reasonable for all elements other than 'IT management, risk and governance'. EMCa sought, but were unable to find, any compelling information to support the proposed capex for ' IT management, risk and governance'.[161] On that basis, EMCa did not consider that SA Power Networks has provided sufficient information to demonstrate the prudency and efficiency of the expenditure.

We have considered both our top down assessment and EMCa's analysis in coming to our position. From a top-down perspective, SA Power Networks' recurrent ICT capex forecast appears reasonable. Given the 'IT management, risk and governance' program is minor in the context of the entire recurrent ICT capex forecast, and the proposed expenditure is consistent with historical trend, on balance, we do not consider this aspect of the forecast is material for the purposes of adjusting the forecast. Our draft decision accepts SA Power Networks' proposed recurrent ICT.

Non-Recurrent ICT capex

From a top-down portfolio perspective, we do not consider that SA Power Network's non-recurrent ICT program as proposed will be able to be delivered by SA Power Networks over the 2020–25 regulatory control period.

From a bottom-up perspective, SA Power Networks has not justified that four of the eight proposed programs would form part of a reasonable forecast of prudent and efficient costs for the 2020–25 regulatory control period.

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[160] SA Power Networks, *Information request 10,* 25 March 2019.

[161] Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 35.

Our substitute forecast for non-recurrent ICT capex is $53.8 million compared to SA Power Networks forecast of $135.5m. This forecast includes the proposed capex for the four program that have been justified. Given that our forecast removes the proposed capex for four projects, we do not consider that there are likely to be any issues with SA Power Networks delivering this program over the period and therefore we have made no deliverability adjustment on this basis.

Program deliverability

EMCa undertook an assessment of the IT program at a portfolio level. EMCa considered that:

- SA Power Networks has not significantly changed its expenditure forecasting methodology for the 2015–20 regulatory control period, which indicates a bias towards overestimation of expenditure
- some projects in the 2015–20 period are behind schedule, such that there is a high likelihood that delivery will extend into the 2020–25 regulatory control period, with consequent implications for dependent projects SA Power Networks proposed
- SA Power Networks understated and/or underestimated the delivery risk of the majority of its projects within its planned portfolio
- it is not clear if and/or how SA Power Networks has taken account of the interdependencies of project completion delays and utilisation of project deliverability resources
- in a number of dependent projects, the portfolio view shows an overlap of project-end and project-start times, which can considerably increase the risk of a total portfolio expenditure overrun.

EMCa concluded that based on its experience, it considered that all projects in the proposed IT portfolio require a 25 to 30 per cent time contingency added. As a result, it is likely that SA Power Networks will incur a lower level of expenditure for the 2020–25 regulatory control period than proposed.[162]

Bottom-up assessment

We have reviewed the information provided to support SA Power Networks' non-recurrent ICT capex forecast, including the business cases and cost-benefit models provided for each project. Where required, we have sought further information from SA Power Networks through information requests. We have also had regard to EMCa's bottom-up review.

[162] Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, pp. 28-31.

Our review of SA Power Networks' supporting documentation has identified that it does not adequately demonstrate the prudency and efficiency of the following four proposed non-recurrent ICT projects.

Assets and Work

SA Power Networks included a wide range of investments as part of this $44.9 million program, which it argues will enable it to defer repex and achieve other efficiency benefits. However, SA Power Networks' business case recognised that its calculations may over-state the benefits of this investment, by assuming deferred repex amounts are never incurred (i.e. deferred in perpetuity).[163]

We asked SA Power Networks to estimate how long it expects repex deferrals to last, and to update its analysis to account for this. SA Power Networks submitted that it expects deferral "will be longer than 10 years", and did not submit a revised NPV.[164] It considered that some work may be performed at lower cost or will not be needed in future, due to falling costs, bundling with other work, and technological or regulatory changes.[165] However, SA Power Networks has not quantified these effects, and the opposite outcome also appears possible.[166]

Our analysis identified that excluding the eventual cost of deferred repex, when considering only a ten year period introduces significant bias. We find that average deferral length would need to exceed 39 years for this program to be NPV positive, once the period of analysis is extended.[167]

SA Power Networks also stated that "deferring these works will best stagger the effects on consumer prices".[168] However, ICT assets have shorter depreciation asset life than repex, so the program may increase prices in the short-term. Regardless, we must consider the long-term interests of consumers, which requires NPV analysis covering a long enough period to capture relevant costs and benefits. Based on these concerns, SA Power Networks has not established that its Asset and Works program is prudent and efficient, we have excluded it from our substitute forecast.

Flow-on effects on repex

SA Power Networks stated that its repex forecast "will need to be increased by $65 million ($2017) if the A&W Program for the 2020–25 RCP is not allowed by the

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[163] SA Power Networks, *2020–25 Regulatory Proposal - Supporting Documentation 5.42 - Assets and Work Program Business Case*, January 2019, p. 7.

[164] SA Power Networks, *Information request 11C - Q3 Cost of eventually replacing assets where replacement is deferred*, 5 April 2019, p. 7.

[165] SA Power Networks, *Information request 11C - Q3 Cost of eventually replacing assets where replacement is deferred*, 5 April 2019, p. 7.

[166] For example, if repair costs increase as assets deteriorate with age.

[167] This uses SA Power Networks' estimates of costs and benefits.

[168] SA Power Networks, *Information request 11C - Q3 Cost of eventually replacing assets where replacement is deferred*, 5 April 2019, p. 7.

AER".[169] However, we and EMCa have not found evidence of this $65 million deferral in SA Power Networks' repex forecast. [170] For example, SA Power Networks has relied on its CBRM for poles repex. Our review of the CBRM's outputs has not identified the consideration of repex deferral as a result of the A&W program. SA Power Networks also estimates deferrals using a model separate from the one it uses to forecast repex. The apparent inconsistency between the forecasting methodologies does not support SA Power Networks' claim that it has indeed incorporated repex deferrals in its repex forecast. Therefore, SA Power Networks has not demonstrated that its repex forecast would need to increase as a result of removal of the A&W program.

SA Power Networks has also not demonstrated the adequacy of its method to estimate repex deferrals. Its forecasts depend on an assumed 25 percent increase in a metric called 'Work Selection Effectiveness' (WSE), which was only determined "based on SME [subject matter expert] judgement and experience".[171] SA Power Networks did not provide a comparison with historical increases in WSE. Further, SA Power Networks states that its CBRM repex forecasts assume perfect allocation of work.[172] This does not appear to allow for an increase in WSE due to the program.

Our repex forecast has not made any adjustment for changes in WSE, since we have largely relied on SA Power Networks' actual repex from 2013–18 as the basis of our substitute forecast. Even if the A&W ends, SA Power Networks forecasts higher deferrals over 2020–25 (due to ICT work completed by 2020) than it achieved over the current period.[173] Therefore, if we accepted SA Power Networks' deferral forecasts, we would need to revise down our repex forecast to account for these deferrals, even if the A&W program ends. Should the A&W program continue, SA Power Networks forecasts an additional $65 million ($2017) in deferrals over 2020–25. Therefore, including the A&W and accounting for deferrals would likely revise down the repex forecast further.

SAP S4 Upgrade

SA Power Networks proposed upgrading its enterprise resource planning software (SAP) to a newer version (S4) at an estimate capex of $26.9 million. This responds to SAP's 2015 announcement that it will cease support for the version SA Power Networks currently uses after 2025.[174]

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[169] SA Power Networks, *Information request 11C - Q1 Assets & Work - Repex Deferrals Baseline*, 5 April 2019, p. 3.

[170] Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, pp. 42-43.

[171] SA Power Networks, *Information request 38 - Q4 Assets and Work*, 28 May 2019, pp. 5-6.

[172] SA Power Networks, *Information request 38 - Q3 Assets and Work*, 28 May 2019, p. 3.

[173] SA Power Networks estimates repex deferrals of $63 million over 2015-20 followed by $142 million over 2020–25 due to ICT work even if the A&W ends in 2020 (since some ICT work done now defers repex that would be incurred in future). If the A&W program continues from 2020 to 2025, it forecasts additional deferrals of $65 million over 2020–25. SA Power Networks, *2020–25 Regulatory Proposal - Supporting Documentation - 5.42 Assets and Work Program Business Case*, January 2019, p. 39.

[174] SA Power Networks, *2020–25 Regulatory Proposal - Supporting Documentation 5.36 - SAP Upgrade Business Case*, January 2019, p. 3.

SA Power Networks has not adequately considered reasonable responses to the loss of vendor support deadline that may be lower cost. Third party providers offer to maintain support for older versions of SAP (e.g. security patching, responses to taxation changes) at reduced fees and beyond SAP's 2025 deadline. Other organisations with significant security requirements (e.g. networks, government agencies) have adopted third party support.[175]

SA Power Networks' business case does not consider this option. When asked, it stated it had ruled out third party support due to poor past experiences of other networks, inadequate patching, the inability to keep up to date with necessary changes (e.g. legal or compliance changes), and future cost escalation due to losing standard upgrade paths and the transition back to SAP support.[176]

However, other organisations use third party support, and SA Power Networks has not discussed whether and how its operations differ sufficiently such that the risks of third party support rule it out as a reasonable alternative. Our consultants, EMCa, identified that third party support providers can provide system patches (e.g. for bug fixes and legal or regulatory changes). [177]

EMCa considered that in the long term, retaining vendor support is likely to involve benefits. However, these benefits are modest as identified by SA Power Networks' proposal ($2.3 million until 2033, $2017).[178] Regarding the possible eventual cost of returning to vendor support, SAP could extend the deadline it issued in 2015, and that the option of third party support considerably reduces the risk of waiting to see if this occurs.[179] Delaying the upgrade also delays the significant business change risks it involves.[180]

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175 The Australian, *Rimini Street Signs 10 Agencies,* 28 January 2019, see: https://www.theaustralian.com.au/business/technology/rimini-street-signs-10-agencies/news-story/18358cf52a20027dfd1c80b9d951103e.

176 SA Power Networks, *Information request 11A - Q6 SAP*, 1 April 2019, p. 6.

177 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 39.

178 SA Power Networks, *2020–25 Regulatory Proposal - Supporting Documentation 5.36 - SAP Upgrade Business Case*, January 2019, pp. 48. Energy Australia submitted that further investing in SAP in the way SA Power Networks have proposed may involve consolidating overly manual IT systems, which may account for the modest benefits. Energy Australia, *SA Power Networks' revenue proposal for the 2020–25 regulatory control period,* 16 May 2019 p. 1.

179 We also agree with stakeholders' concerns that networks should exercise their bargaining power with vendors, so expect to see potentially lower cost options explored without treating vendor issued deadlines as a fait accompli. SACOSS, *SACOSS submission in response to AER Issues Paper on the SA Power Networks electricity determination 2020–25,* 10 May 2019 p. 11; CCP, *Advice to the AER on the SA Power Networks 2020–25 Regulatory Proposal,* 16 May 2019, p. 46.

180 SA Power Networks has identified change management issues, and EMCa considers that SA Power Networks has not adequately assessed the delivery risk associated with the project. SA Power Networks, *2020–25 Regulatory Proposal - Supporting Documentation 5.36 - SAP Upgrade Business Case*, January 2019, p. 5.

SA Power Networks has not established that upgrading is lower cost than third party support, or that third party support is not feasible to maintain service standards. Therefore, we have not included the SAP S4 Upgrade in our substitute estimate.

Worker Safety - Fatigue Management

SA Power Networks proposed $5.8 million for fatigue management as it considers that fatigue risk will increase over the 2020–25 period due to "environmental, technological and organisational changes, including those initiated by our Assets and Work program". To address this risk and comply with regulatory obligations, it has proposed this $5.8 million program to automate and improve its fatigue management processes.[181]

SA Power Networks has identified that its current fatigue management procedures are compliant, and it has not established the risks are likely to materially increase in a way such that its current procedures are unable to address.[182] Our consultant, EMCa, similarly finds that SA Power Networks has not established that any increased fatigue risk jeopardises regulatory compliance.[183]

SA Power Networks has also not quantified the value of the risk that would be avoided through the Worker Safety program, or forecast how this risk may change as a result of the factors it identifies. SA Power Networks states a negative NPV (-$7.2 million, $2017) for the program.[184]

For the current regulatory control period, we approved an In Vehicle Monitoring System (IVMS) to address the issue of driving safety, on the basis of "its increasingly widespread adoption throughout industry".[185] The Worker Safety program proposes extending these systems and adding 'active' driver fatigue management. While SA Power Networks has identified examples where its proposed additional systems have been implemented, it has not established that this is widespread practice for electricity networks or in comparable industries.[186]

SA Power Networks has not established that this program is required for regulatory compliance, is prudent or efficient, or that it is widespread industry practice, so we have not included it in our substitute forecast.

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181 SA Power Networks, *2020–25 Regulatory Proposal - Supporting Documentation 5.41 - Worker Safety: Fatigue Risk Management Business Case*, January 2019, p. 4.

182 SA Power Networks, *Information request 11B - Q9 Worker Fatigue*, 1 April 2019, p. 7. We also note that one of these factors is the Assets and Work program, which we do not consider efficient.

183 For example, to jeopardise SA Power Networks' current exemption from the Heavy Vehicle National Law (South Australia).

184 SA Power Networks, *2020–25 Regulatory Proposal - Supporting Documentation 5.41 - Worker Safety: Fatigue Risk Management Business Case*, January 2019, p. 13.

185 AER, *Final Decision SA Power Networks Distribution Determination – attachment 6, Capital Expenditure,* October 2015, p. 133.

186 SA Power Networks, *Information request 11B - Q9 Worker Fatigue*, 1 April 2019, p. 10.

Ring Fencing Compliance IT Solution

SA Power Networks' unregulated related entity, Enerven, pays fees to share the use of SA Power Networks' ICT assets. Our compliance report found that this may allow Enerven staff to access information that would breach the Ring-Fencing Guideline.[187] SA Power Networks has proposed an IT solution, of a total value of $4 million, to ensure compliance with the Guideline.

SA Power Networks could ensure compliance with the Ring Fencing Guideline by excluding Enerven from use of its ICT assets, at zero capex cost. This would forgo an amount of Shared Asset Unregulated Revenue that Enerven currently pays SA Power Networks to use these assets.[188] However, SA Power Networks has not performed NPV analysis to establish that the program is in the interests of consumers based on this amount, compared to its capex costs. For this reason, we agree with the SA Government that capex costs for this project should not be added to the regulatory asset base (RAB).[189] SA Power Networks also has the option to 'self-fund' this project to recover any revenue received from Enerven that is not shared with regulated customers.

SA Power Networks has not established that this program is a lower cost means of complying with the Ring-Fencing Guideline than excluding Enerven from its shared ICT systems, so we have not included it in our substitute forecast.

A.7 Fleet

Fleet capex covers expenditure for purchasing new vehicles and related items, including mounted plant. Fleet incorporates light fleet (passenger and light commercial vehicles) and heavy fleet. Heavy fleet typically comprises elevated work platforms (EWPs), crane borers and other heavy commercial vehicles.

A.7.1 Draft decision

SA Power Networks has not justified that its forecast fleet capex of $116.6 million forms part of a total capex forecast that reasonably reflects the capex criteria. The service life and unit rate assumptions used in the fleet model SA Power Networks provided exceed efficient costs. Our substitute estimate is based on adjustments to SA Power Networks fleet service lives and unit rates, as well as an adjustment to correctly account for SCS usage.

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187 AER, *Annual Compliance Report on Electricity Distribution Ring-Fencing Guideline*, 5 March 2019, p. 10.

188 SA Power Networks, *Information request 38 - Q1 Ringfencing*, 30 May 2019, p. 1.

189 SA Government, *Government of South Australia Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2020–25,* 15 May 2019, p. 2.

Table 5.9 summarises SA Power Networks' proposed fleet capex forecast and compares this to our draft position.

Table 5.9 Draft decision on SA Power Networks' forecast fleet capex ($ million, 2019–20)

Category	Proposal	Position	Difference
Total	**116.6**	**79.9**	**-36.7**

Source: SA Power Networks, *Regulatory Proposal attachment 5 - Capital expenditure* and AER analysis.

A.7.2 SA Power Networks' proposal

SA Power Networks' proposed a fleet capex forecast of $116.6 million.[190] This represents a 25 per cent increase from SA Power Networks actual and estimated fleet capex of $93.0 million over the current regulatory control period.[191]

SA Power Networks stated that over the 2015–20 regulatory control period it estimates it will underspend its fleet allowance of $134.8 million by 31 per cent. SA Power Networks submitted that the underspend is due to the highly competitive supply market and its decision not to increase fleet volumes as much as it had forecast prior to the 2015-20 period.[192]

A.7.3 Reasons for draft decision

Our analysis has identified that SA Power Networks is currently among the most costly providers for fleet on a per employee basis. Figure 5.16 shows SA Power Networks' motor vehicles expenditure per employee basis, compared to other states. SA Power Networks is forecasting an increase in fleet expenditure per employee, this forecast is unlikely to be reflective of efficient costs for a prudent operator.

CCP14 and the SA Government also raised concerns with SA Power Networks' fleet capex proposal, emphasising the substantial underspend over the current regulatory period and the need to understand why expenditure is forecast to increase in the competitive conditions SA Power Networks identifies.[193]

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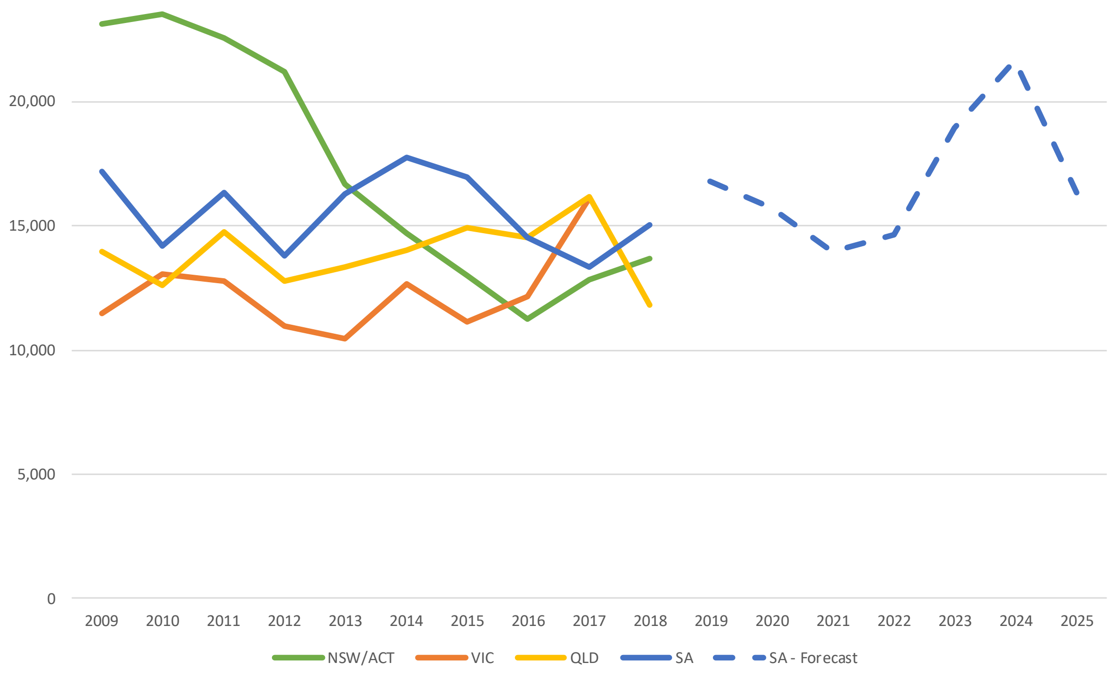
190 SA Power Networks, *2020–25 Regulatory Proposal – attachment 5 - Capital Expenditure*, January 2019, p. 111.

191 SA Power Networks, *2020–25 Regulatory Proposal – Reset RIN 2020–25,* February 2019.

192 SA Power Networks, *2020–25 Regulatory Proposal – attachment 5 - Capital Expenditure*, January 2019, pp. 109-10; SA Power Networks, *Regulatory Proposal attachment 5.30 - Strategic Fleet Plan 2020-2025*, 18 January 2019, p. 21.

193 CCP, *Advice to the AER on the SA Power Networks 2020–25 Regulatory Proposal,* 16 May 2019, p. 19; SA Government, *Government of South Australia Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2020–25,* 15 May 2019, p. 3.

Figure 5.16 Motor vehicles expenditure per employee by state ($ million, 2019–20)[194]



Sources: SA Power Networks, *Reset RIN 2020–25* and AER Analysis.

Note: Year refers to calendar year for Victoria and second year of financial year for other states.

We performed a detailed bottom up assessment of SA Power Networks' fleet capex proposal, resulting in adjustments in each of the areas below.

EWP Life Extension and Service Life Alignment

SA Power Networks' current policy is to replace EWPs after 10 years of service life.[195] Our analysis indicates that extending EWP life to 15 years is lower cost, based on SA Power Networks' NPV calculations. We also considered further arguments raised by SA Power Networks in support of its EWP service life policy, which are discussed below.

Replacement Life Adjustments

SA Power Networks submitted NPV calculations to support the efficiency of its EWP service life, which include costs of 're-trucking'.[196] However, SA Power Networks has not established that re-trucking at ten years is widespread industry practice or a

[194] This includes capex and opex related expenditure.

[195] SA Power Networks, *2020–25 Regulatory Proposal – attachment 5 - Capital Expenditure*, January 2019, p. 111.

[196] SA Power Networks, *Information request 3 - Q3a Fleet and Plant Questions,* 22 February 2019, p. 22; SA Power Networks, *Information request 23(B) - Q2b Fleet and Plant Questions,* 1 May 2019, p. 3. This involves replacing the truck / chassis as part of refurbishing an EWP tower, rather than extending the lives of both truck and tower.

compliance obligation.[197] SA Power Networks extends crane borer life to 14 years in line with efficient industry practice, and uses a 15 year replacement cycle for other trucks and heavy commercial vehicles.[198] Our review of Energex and Ergon Energy's fleet models indicate that they do not generally practice re-trucking when extending EWP life, indicating that re-trucking is not widespread industry practice.[199]

SA Power Networks did not provide any NPV analysis excluding re-trucking costs when requested.[200] Once these significant costs are excluded from SA Power Networks' NPV analysis, we find that EWP life extension to at least 15 years is lower cost than replacement at 10 years.

Not all EWPs will necessarily pass the inspection that extension requires. Across its EWP fleet, our analysis identified that Energex and Ergon Energy refurbish 45 per cent of EWPs that reach 10 years of service life.[201] Our substitute estimate assumes that SA Power Networks achieves this rate. We assume that the cost of life extension is equal to the cost submitted by SA Power Networks excluding re-trucking costs.

SA Power Networks' EWP forecasts also include inconsistent assumptions regarding the 'spread' of replacement costs before replacement is due.[202] For consistency, we have removed this portion from our forecast, which strictly aligns costs incurred with service lives. The extension of EWP's life extension in 45 percent of cases and the consistent application of service lives results in a reduction of $12.8 million.

SA Power Networks' engagement and AER response

We have provided SA Power Networks with our preliminary findings, SA Power Networks submitted that its approach is consistent with its obligations under the WHS

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197 SA Power Networks, *Information request 23(D) - a) and b) Follow up questions regarding EWP refurbishment*, 13 June 2019, pp. 1-4.

198 SA Power Networks, 2020–25 *regulatory proposal - Supporting Documentation 5.30 - Strategic Fleet Plan 2020-2025*, January 2019, p. 23.

199 Ergon Energy's bottom up fleet model list EWP trucks and towers as separate items, and for all EWPs (including those that have been life extended) dates in service are the same for both truck and tower. NPV analyses provided by Ergon and Energex indicate refurbishment costs for EWPs are broadly consistent with those included in SA Power Networks analysis once re-trucking costs are excluded from SA Power Networks' assumptions.

200 SA Power Networks, *Information request 23(D) - a) and b) Follow up questions regarding EWP refurbishment*, 13 June 2019, pp. 1-4.

201 This combines the stated refurbishment percentage achieved for EWPs 14 metres or greater with the number of smaller EWPs owned by EQ due for replacement over a comparable period (that we assume are not refurbished). This percentage is also consistent with data SA Power Networks has collected, indicating that chassis condition did not require significant remedial work for 14 out of 33 EWPs (42 per cent) over 2013-14. We also note that Energex and Ergon Energy own a larger proportion of EWPs smaller than 14 metres than is indicated by SA Power Networks' fleet model, indicating that our assumed EWP replacement rate could be conservative. SA Power Networks, *Information request 23(D) - a) and b) Follow up questions regarding EWP refurbishment*, 13 June 2019, p. 2.

202 For EWPs due for replacement in the first half of 2020-21, SA Power Networks assumes the full replacement cost is incurred over this six months, i.e., within the 2020–25 regulatory control period. But for EWPs due for replacement over the first half of 2025-26, SA Power Networks assumes a portion of the total replacement cost is incurred over the 2020–25 regulatory control period.

Act and Regulations, and with our previous determinations, and identified possible opex changes as a concern.[203] However, Australian Standards allow for EWP life extension, and SA Power Networks has not provided evidence that life extended EWPs pose a safety risk that is significantly different from other EWPs, such as to risk non-compliance with its obligations under the WHS Act and Regulations.

SA Power Networks identified two previous determinations in support of its position: the 2019–2024 determination for Evoenergy, and its own previous determination, after it ceased EWP life extension in 2012.[204] However, urban providers such as Evoenergy tend to have a larger proportion of EWPs smaller than 14 metres, for which life extension is less likely to be efficient. Regarding our previous determination for SA Power Networks, the least cost practice can change over time in response to movements in unit rates, and that our 2015–20 preliminary decision stated that the difference in NPVs for replacement at 10 years compared to 20 years for EWPs differed very slightly.[205] SA Power Networks also stated that the NPV analysis it submitted at the time included re-trucking costs.[206]

Regarding changes in opex that extending service lives may incur, SA Power Networks' NPV calculations incorporate forecasts for increased maintenance costs. SA Power Networks has not performed analysis establishing that these increases would warrant a positive opex step change. We also note that SA Power Networks' 2015–20 proposal did not include a negative opex step change relating to the decision to cease extending EWP life in 2012.[207]

Unit Rates Adjustments

We found SA Power Networks' assumed unit rates were 20 percent higher than average historical unit rates where we were able to match model and body types, adjusting for CPI inflation.[208] Given SA Power Networks identified competitive supply conditions as a reason for its fleet underspend over the current regulatory period, and

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203 SA Power Networks, *Information request 23(D) - a) and b) Follow up questions regarding EWP refurbishment*, 13 June 2019, p. 4.

204 SA Power Networks, *Fleet Assessment Model Feedback,* 9 July 2019, p. 2.

205 AER, *Preliminary Decision SA Power Networks distribution determination – attachment 6 – Capital Expenditure*, 30 April 2015, p. 6-130.

206 SA Power Networks, *Information request 23(D)* - a) and b) Follow up questions regarding EWP refurbishment, 13 June 2019, p. 1. We also note that SA Power Networks has submitted NPV analysis for a 14 metre EWP, and that its fleet model indicates that it owns a significant number of EWPs larger than this. Life extension tends to prove more viable for larger EWPs.

207 SA Power Networks, *Reset RIN 2015-20,* December 2013.

208 To do this, we used the historical ledger SA Power Networks submitted to compare its forecast prices with average prices paid historically by vehicle model and body type, where we were able to match these (light fleet and substation truck / cranes). SA Power Networks, *Information request 23(B) -Q1(b) Historical Unit Costs and Volumes*, 1 May 2019, p. 2.

motor vehicles prices have declined in real terms, SA Power Networks has not established that the unit rates it has assumed are efficient.[209]

Our substitutes applies historical unit rates (adjusted for inflation) for vehicles types we were able to match, such as light fleet and substation trucks / cranes, to reflect likely efficient costs, which results in a reduction of $8.1 million.

Senior Staff Vehicle Adjustments

SA Power Networks proposed $10.6 million in SCS capex for vehicles for senior staff (Total Employment Contract or TEC vehicles). We have identified the following concerns:

- SA Power Networks permits private use of these vehicles, and includes their full purchase cost in its forecast.[210] It is more appropriate that SA Power Networks fund the private use purchase component of these vehicles through salaries, noting that when SA Power Networks began purchasing TEC vehicles in 2015,[211] no negative opex step change was involved.[212]
- We have identified that the assumed service lives for TEC Vehicles are three years or less, which is shorter than the five year life for ordinary passenger and light commercial vehicles. We have also identified that the assumed unit rates are higher than for models in the passenger and light commercial vehicles category. SA Power Networks did not submit NPV analysis in support this difference in policy, so it has not established that a more frequent replacement and higher unit rates are efficient.[213] Our substitute assumes a five year service life and applies the unit rate by 'body type' from the passenger and light commercial vehicles category.
- SA Power Networks also forecasts net growth of five TEC vehicles (without subtractions elsewhere) but has stated that it forecasts zero vehicle volume growth overall.[214]

Based on the concerns above, SA Power Networks has not established that its TEC vehicles capex is prudent and efficient. Our substitute estimate reduces capex by

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209 The price index for motor vehicles in Adelaide declined by 9 per cent in real terms from June 2015 to June 2019. AER Analysis based on Australian Bureau of Statistics, *6401.0 Consumer Price Index, Australia,* 31 July 2019, Table 9.

210 SA Power Networks, *Information request 23(C) - Follow up TEC Q5(c)*, 5 June 2019, p. 3.

211 SA Power Networks*, Reset RIN 2015–20*, December 2013.

212 SA Power Networks states that it does not record private use through log books, but assumes 20 percent private use for Fringe Benefits Tax purposes. SA Power Networks, *Information request 23(C) - Follow up TEC Q5(c)*, 5 June 2019, p. 3.

213 SA Power Networks, *Information request 23(C) - Q5(a) Follow up TEC*, 5 June 2019, p. 2. Regarding choice of model, SA Power Networks states "[t]he TEC employee may nominate their preferred vehicle and must seek approval from their general manager". Forecast unit rates in this category are materially higher than for comparable vehicle types (passenger and light commercial vehicles). SA Power Networks, *Information request 23(B) - Q5(c) TEC Vehicles*, 29 May 2019, p. 7.

214 SA Power Networks, *Information request 23(B) - Q5(c) TEC Vehicles*, 29 May 2019, p. 7; SA Power Networks, *2020–25 Regulatory Proposal – attachment 5 - Capital Expenditure*, January 2019, pp. 111.

$7.5 million, which adjusted TEC capex by 20 per cent to account for private use, assumes a five year service life, applies the unit rate by 'body type' from the passenger and light commercial vehicles category and retains the zero vehicle growth assumption.

Standard Control Services Adjustments

SA Power Networks' submitted reset RIN stated that its total vehicle pool varies across vehicle type between 87 and 94 percent for SCS purposes.[215] However, our analysis illustrated that SA Power Networks bottom-up model has allocated its entire vehicle pool to SCS capex. Our substitute applied the SCS percentages stated in the reset RIN to our substitute fleet forecast by vehicle type.

A.8 Property

The property portfolio for SA Power Networks includes 30 depots, 6 located throughout the Adelaide metropolitan area and 24 located in regional cities and country/rural areas. SA Power Networks also has 9 commercial and 10 industrial properties in the metropolitan area, both owned and leased.

A.8.1 Draft decision

SA Power Networks has not satisfied us that its forecast property capex of $61.5 million forms part of a total capex forecast that reasonably reflects the capex criteria. We have not included any allowance for property capex in our substitute estimate. SA Power Networks has not provided a sufficient demonstration of need, rigorous options analysis and cost benefit assessment to support the proposed expenditure.

It is likely that a prudent and efficient investment in property capex is lower than SA Power Networks' forecast, and likely lower than historical expenditure. However, based on the information before us, we are not satisfied that any specific adjustment to SA Power Networks' forecast would necessarily result in a reasonable estimate of prudent and efficient costs.

Table 5.10 summarises SA Power Networks' proposed property capex forecast and compares this to our draft position.

Table 5.10 Draft decision on SA Power Networks' forecast property capex ($ million 2019–20,)

Category	Proposal	Position	Difference
Total	**61.5**	**0.0**	**-61.5**

Sources: SA Power Networks, *Regulatory Proposal attachment 5 - Capital expenditure* and AER Analysis.

215 SA Power Networks, *Reset RIN 2020–25*, February 2019. Tab 2.6

We note that our draft decision is not that SA Power Networks has not made the case for expenditure on property all together, as SA Power Networks will still recover costs relating to ongoing maintenance and lease fees through its opex allowance. Instead, we consider that SA Power Networks has not evidenced the requirement for capital works to be undertaken at these sites, nor has it provided evidence of capital costs required under a base case option.

We will have regard to any new information SA Power Networks can provide as part of its revised proposal to determine whether any capital work is required for the prudent and efficient management of SA Power Networks' property portfolio over the forecast regulatory control period.

A.8.2 SA Power Networks' proposal

SA Power Networks' proposal includes a property capex forecast of $61.5 million. This represents a 13 per cent increase from SA Power Networks' actual and estimated property capex of $54.3 million for the current regulatory control period.

SA Power Networks provided a model of 28 individual projects targeting works at specific properties totalling a value of $71.0 million.[216] SA Power Networks submitted it applied a top down reduction of $9.5 million. SA Power Networks submitted that this was done to "reflect customer feedback that the forecast should be closer to historic spend."[217]

SA Power Networks' property forecast is made up of five major projects account, which account for 65 per cent of the total capex forecast.[218] All other identified works are each less than $3.0 million in cost, at an average cost of $1.4 million.

A.8.3 Reasons for draft position

We have had regard to responses to information requests,[219] stakeholder submissions from the SA Government[220] and the ECA,[221] who expressed concern with the proposed forecast property capex. These submissions noted that SA Power Networks underspent on property capex in the current regulatory control period, driven by project delays or deferrals. They considered that further information was required to justify the need for the proposed expenditure, to ensure that SA Power Networks' ex-ante

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216 SA Power Networks, *Information Request 016*, 12 March 2019.

217 SA Power Networks, *Information Request 016*, 12 March 2019.

218 In support of its property capex forecast, SA Power Networks provided its Property Services Strategy and a series of Accommodation Audit Reports by Rider Levett Bucknall. See SA Power Networks, *Regulatory Proposal attachment 5.31 – Property Services Capital Expenditure 2020–25*, January 2019.

219 During the review, we requested business cases for major projects as these were not provided as part of SA Power Networks' proposal documentation. See, AER, Information Request 003, 22 February 2019.

220 SA Minister for Energy and Mining, *Submission on SA Power Networks Regulatory Proposal 2020–25*, 16 May 2019.

221 ECA, *Submission on SA Power Networks Regulatory Proposal 2020–25*, 16 May 2019.

forecast is reasonable. We discuss our finding for major and minor projects in turn below.

Major Projects

The business cases state that the driver for the projects is compliance with health and safety legal requirements. However, the business cases do not specify which obligations. The need to address specific non-compliance issues do not in itself justify the proposed works, such as demolition and rebuild of entire buildings.

We requested clarification as to the nature of these issues, noting that for the Angle Park North project, the benefit was to "[r]esolve several WHS issues pervading the site, namely potential risks to pedestrians”[222]. SA Power Networks submitted that:

- the reference to health and safety legal requirements was “a typographical error in transcription of the business case”[223] and that instead, it should have read as building code compliance issues. SA Power Networks is only required to bring a building up to current building code requirements where they undertake any major building works and then only in relation to that portion of the building subject to those works. Therefore, non-compliance with building code requirements is not in itself demonstration of the need for major building works to be completed in the first place.[224]
- In relation to the Angle Park North site, project work was completed within the current regulatory period to address the immediate concerns.

As such, SA Power Networks has not adequately demonstrated the need for the Anlge Park North project. Had SA Power Networks established the need, it is not evident that the proposed works, in its business cases, represent the most efficient way to comply. We have identified the following issues:

- SA Power Networks' options analysis is binary, upgrade or ‘do-nothing’.[225] It is good practice to analyse the optimal timing of these investments or consider options to only address outstanding compliance issues. Such an analysis would enable SA Power Networks to identify possible cases where it can prudently defer entire or parts of projects into subsequent regulatory control periods and therefore spend less than forecast. For example, SA Power Networks was able to prudently defer the Seaford project from the current period and learn from the design and approach at the Angaston Depot.
- SA Power Networks has not substantiated the alternatives to 'do-nothing' through quantitative analysis. For the Angle Park North, Keswick and Marleston North projects it is stated that 'do-nothing' is not preferred, as “it will be more expensive in

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[222] SA Power Networks, Angle Park North Business Case, 22 February 2019, p. 7.

[223] SA Power Networks, *Information Request 045*, 12 June 2019, p. 1.

[224] Development Act 1993 and Regulations 2008.

[225] See SA Power Networks, *2020–25 Regulatory Proposal - Supporting Documentation 5.31 – Property Services Capital Expenditure 2020–25*, January 2019, p. 19.

the long term."[226] However, the forecast cost of 'do-nothing' is $0, which demonstrates that the option was not adequately assessed. If it were considered, the 'do-nothing' option would be associated with a cost, which would demonstrate that it is, in fact, more expensive in the long-run.

- SA Power Networks did not consider a ‘do-nothing’ or base-case option for the Seaford depot project in its options analysis, as such SA Power Networks has not evidenced the prudency or efficiency of changing from its current operations.
- SA Power Networks has not undertaken any cost-benefit analysis, to demonstrate that the quantified benefits are likely to exceed the costs. As such, there is no evidence that SA Power Networks has chosen the economically optimal decision in developing its forecast.

The lack of robust economic analysis is likely to lead to a forecast that is higher than the prudent and efficient level. While we acknowledge that SA Power has applied a top-down adjustment to its bottom-up forecast, the application of this reduction essentially arrives at an estimate that is equal to the average of the past eight years from 2010–11 to 2017–18. SA Power Networks has not explained why this reduction is appropriate, why it is efficient or which projects were removed.

Further to the above issues:

- SA Power Networks has identified opex savings from the proposed works, however, SA Power Networks has submitted that these savings are not factored into forecast opex.[227] This is evidence that a portion of the investment cost should not be incurred by consumers as SA Power Networks benefits through the EBSS incentive scheme.
- SA Power Networks has included a contingency allowance in the forecast based on 10 per cent of all architectural, structural, engineering services and civil works costs.[228] Consistent with previous determinations, we consider that consumers should not fund these costs.

Minor projects

We have reviewed SA Power Networks' minor works for which no business cases were provided.[229] SA Power Networks has not established the need, for example:

- SA Power Networks has included costs relating to landscaping work and roof replacements. Landscaping work would only be needed on new developments,

226 SA Power Networks, *Business Case – Angle Park North*, 31 January 2019, p. 6.

227 See the section 'Regulatory treatment' of each business case.

228 Contingency costs are a project management tool to account for possible added costs of delays or other possible outcomes. See SA Power Networks, *Information Request 016*, 12 March 2019.

229 SA Power Networks, *2020–25 regulatory proposal - Supporting Documentation 5.31 - Property Services Capital Expenditure,* 31 January 2019.

after which, work would only be maintenance of those gardens. As to roof replacements, SA Power Networks has not demonstrated the need for the entire roof to be replaced as opposed to maintaining the current roof, by replacing any unserviceable roofing panels. Further, given the nature of these works, these appear to be of more opex in nature and therefore would be included in base opex.

- SA Power Networks has also included costs relating to undercover EWP parking at some sites. We asked SA Power Networks to provide justification for the inclusion of these works.[230] SA Power Networks listed qualitatively a variety of benefits from undercover EWP parking. However, without benefit quantification, it is not evident that these benefits justify the proposed costs.

SA Power Networks also included costs to install wash bays at certain sites.[231] SA Power Networks submitted that it has an obligation to comply with current regulations and guidelines.[232] Our analysis indicates that there is no requirement to upgrade current facilities, as the regulations have not altered such that new investments are required. Where existing facilities do not comply with the relevant regulations, SA Power Networks would need to provide evidence, such as a compliance order, to demonstrate its obligations.

A.9 Other non-network

SA Power Networks has proposed capex for two 'other' non-network categories. SA Power Networks referred to these categories as non-network telecommunications and tools and equipment.

A.9.1 Draft decision

SA Power Networks has not justified that its forecast 'other' non-network capex of $42.2 million forms part of a total capex forecast that reasonably reflects the capex criteria. We have included an amount of $30.4 million for other non-network capex in our substitute estimate, a 28 per cent reduction to SA Power Networks' forecast.

Our substitute for other non-network capex does not include proposed capex for the ADMS/OMS upgrade project. In our view, SA Power Networks has not provided a sufficient business case for this expenditure that adequately demonstrates the prudency and efficiency of the project.

Table 5.11 summarises SA Power Networks' proposed other non-network capex forecast and compares this to our draft position. We have accepted SA Power Networks' forecast for tools and equipment, which are 20 per cent lower than actual costs over the past five years.[233]

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230 AER, *Information Request 045*, 4 June 2019.

231 SA Power Networks, *2020–25 regulatory proposal - Supporting Documentation 5.31 - Property Services Capital Expenditure,* 31 January 2019.

232 State and Federal Biosecurity Acts and Regulations, EPA codes of practice and industry guidelines.

233 SA Power Networks, *2020–25 Regulatory Proposal - RIN 3 - Workbook 3 - CA - recast historical*, January 2019.

Table 5.11 Draft decision on SA Power Networks' forecast other non-network capex ($ million, 2019–20)

Category	Proposal	Position	Difference
Non-Network Telecommunications	**21.3**	**9.6**	**-11.7**
TNC Management	*2.7*	*2.7*	-
UPAX/Business Telephone Network	*2.1*	*2.1*	-
OT security	*4.8*	*4.8*	-
AMDS/OMS Upgrade	*11.7*	*0.0*	*-11.7*
Tools and Equipment	**20.9**	**20.9**	**-**
Total Other Non-Network Capex	**42.2**	**30.4**	**-11.7**
Modelling Adjustment	-	*-0.1*	*-0.1*
Draft Decision on Total Other Non-Network capex	**42.2**	**30.3**	**-11.9**

Sources: SA Power Networks, *Regulatory Proposal attachment 5 - Capital expenditure*, SA Power Networks, *Response to AER Information Request 12* and AER analysis.

A.9.2 SA Power Networks' proposal

SA Power Networks' initial proposal includes a capex forecast of $42.2 million. This is comprised of $21.3 million for non-network telecommunications and $20.9 million for tools and equipment. SA Power Networks has submitted that these expenditures primarily reflect business as usual and are based on historical expenditure.

SA Power Networks has submitted that its non-network telecommunication capex is required to enable continuous day to day operation and monitoring of its distribution and telecommunications network. SA Power Networks has included its Advanced Distribution Management System (ADMS) upgrade under this category. While SA Power Networks' tools and equipment capex is minor expenditure relating to the replacement of tools and equipment used in SA Power Networks' day to day operations.

A.9.3 Reasons for draft decision

In coming to our view on this category, we have had regard to EMCa's views, who undertook a bottom-up review of the telecommunications component of the other non-network capex category. We have had regard to the SA Government public submission, which acknowledged the importance of cyber security in the current environment, but asked for assurance that the proposed operational technology security capex was fully justifiable.[234] We discuss our review of the non-network telecommunication and the basis for our substitute estimate below.

Non-network telecommunications

SA Power Networks' network operational IT forecast is comprised of four programs: TNC Management; UPAX/Business telephone network; OT security; and ADMS/OMS Upgrade.

TNC Management; UPAX/Business telephone network; and OT security.

SA Power Networks has demonstrated that its capex for TNC Management, UPAX/Business telephone network and OT Security is prudent and efficient

We asked SA Power Networks to provide a bottom-up forecast for each of these programs.[235] On review of these models, we are satisfied with the forecasting methodology applied arrives at a prudent and efficient level of expenditure. EMCa has reviewed the business cases provided for these expenditure categories and assessed that the forecast expenditure for these programs was prudent and efficient.[236]

ADMS upgrade

SA Power Networks has proposed $11.7 million for an upgrade of its ADMS. This is comprised of a proposed hardware upgrade in 2020–21 and software upgrade in 2023–24.

We asked SA Power Networks to provide the business case for this project.[237] SA Power Networks referred us to a report by DGA Consulting on a variety of ‘network control’ projects,[238] one of which is the proposed ADMS upgrade.

We have reviewed the DGA report and concluded that it does not provide sufficient information to demonstrate the prudency and efficiency of the investment. At a high-level, this report does not adequately present the need, or provide any options analysis and cost-benefit assessment to support the proposed investment. As such, we do not consider that SA Power Networks has demonstrated this project against the capex criteria.[239] We expect SA Power Networks to provide a revised business case to address our concerns in its revised proposal.

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234 SA Minister for Energy and Mining, *Submission on SA Power Networks Regulatory Proposal 2020–25*, 16 May 2019, p. 2.

235 AER, *Information Request 027*, 06 May 2019.

236 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, pp. 46-47.

237 AER, *Information Request 3*, 06 February 2019.

238 SA Power Networks, 2020–25 *regulatory proposal - Supporting Documentation 5.23 – DGA Consulting – Network Control – Projects Review*, January 2019.

239 NER, cl. 6.5.7(c).

The DGA states that the project's total cost is $7.4 million. We asked SA Power Networks to explain the reasons for the discrepancy between the proposed expenditure and this business case. SA Power Networks submitted that this report relates only to the software component of the forecast only.[240] SA Power Networks subsequently advised that the business case for the hardware component would be provided as part of its Revised Proposal.[241] We will consider this additional information determining our final decision.

We recognise from the information provided that it is not that the ADMS version SA Power Networks currently operates will become unsupported, but rather that the Windows operating systems will be not supported. While the vendor support and licencing agreement for the ADMS would provide for maintaining the ADMS software system, costs would be required for the periodic replacement of the hardware that the ADMS is running on. The replacement of the hardware with a modern equivalent would also include replacing the operating system that the hardware uses. As such, it would not usually be necessary to install a new version of the ADMS when doing a hardware refresh.

We expect that, in order for SA Power Networks to maintain the current ADMS, it would only need to refresh the hardware with a modern equivalent. This would sufficiently address the need to the Windows' upgrade. The prudent timing of this expenditure would be either when the hardware could no longer be efficiently supported or when support for Windows is no longer available. The DGA report does not consider these options. As such, SA Power Networks has not demonstrated the need for an upgrade to the ADMS software.

SA Power Networks has submitted that it "is not claiming any benefits as a result of the upgrade other than to have its critical control systems remain on a version of software that is supported by the vendor."[242] However, DGA is clear in its report that the ADMS is being augmented rather than being a simple replacement. While the DGA report qualitatively outline the benefits, these benefits have not been quantified to justify the proposed investment.

DGA also outlines that the intention of the project is to go to an updated version, which will coincidently include acquiring the 'DERMS' module. DGA state that DERMS will be critical to the management and control of the increasing levels of DER connecting to the network over the next regulatory period. Therefore, it is clear that this project is not simply rolling the current ADMS onto a currently supported production version, but rather it is an upgrade to include DERMS and integrate to the outage management system. SA Power Networks has not provided any evidence to demonstrate the prudency and efficiency of these activities. EMCa echoed many of our concerns and

240 SA Power Networks, *Email to the AER*, 5 April 2019.

241 SA Power Networks, *Response to AER Information Request 027*, 17 May 2019, p. 1.

242 SA Power Networks, *Response to AER Information Request 027*, 17 May 2019, p. 2.

concluded that "there is insufficient information to conclude that the proposed ADMS software upgrade program is likely to be prudent and efficient."[243]

A.10 Capitalised overheads

Overhead costs are business support costs not directly incurred in producing output, or costs that are shared across the business and cannot be attributed to a particular business activity or cost centre. The allocation of overheads is determined by the Australian Accounting Standards and the distributor's cost allocation methodology.

A.10.1 Draft decision

SA Power Networks has not established that its proposed capitalised overheads forecast of $62.4 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included $56.0 million for capitalised overheads, which is $6.4 million (10.3 per cent) lower than SA Power Networks' forecast, in our substitute estimate. This includes an adjustment to reflect the lower support requirements of direct capex for our substitute estimate.

SA Power Networks also proposed a negative $38.3 million superannuation adjustment to correctly account for the capital allocation of the superannuation contributions SA Power Networks is required to make to the Electricity Industry Superannuation Scheme and other superannuation schemes in the 2020–25 regulatory control period.[244] While we acknowledge that this is not an overhead but rather an accounting adjustment, we accept SA Power Networks' proposed negative $38.3 million superannuation adjustment, which has been attributed to its capitalised corporate overheads.

A.10.2 SA Power Networks' proposal

SA Power Networks forecasts $62.4 million in capitalised overheads for 2020–25. This is $6.9 million, or 12 per cent, higher than its expected expenditure of $55.5 million in the 2015–20 regulatory control period.

A.10.3 Reasons for draft decision

In coming to our position, we have assessed SA Power Networks' methodology, historical costs and trends, and total overheads across SA Power Networks' opex and capex functions.

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243 Energy Market Consultants Associates, *Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 48.

244 This accounts for the difference in between regulatory and accounting treatments. See, SA Power Networks, *Regulatory proposal*, January 2019, p. 112.

Adjustment to overheads

Reductions to SA Power Networks' forecast expenditure should result in a reduction to SA Power Networks total overheads. Given that our assessment of SA Power Networks proposed direct capex, demonstrates that a prudent and efficient distributor would not undertake the full range of direct expenditure contained in SA Power Networks proposal. It follows that we would expect some reduction in the size of SA Power Networks capitalised overheads. We do accept that some of these costs are relatively fixed in the short term and so are not correlated to the size of the expenditure program. However, we maintain that a portion of the overheads should vary in relation to the size of the expenditure. In response to our information request, SA Power Networks identified the annual fixed and variable proportion of overheads. On average, the fixed and variable ratio was 61 per cent and 39 per cent respectively for network capex categories.[245]

We accept the annual ratios and have adopted this ratio in our adjustment. This adjustment reflects our substitute forecast capex for categories where for which overheads have been allocated. We note our substitute forecast is higher than SA Power Networks' historical actual overheads. This is driven by both an increase in total overheads and increase in the allocation of total overheads from 8.6 per cent in the actual years to 10.5 per cent to SCS capex in the forecast years.

Assessment of superannuation adjustment

Our review has identified that SA Power Networks based this adjustment on its superannuation adjustment in 2017–18.[246] SA Power Networks demonstrated that its most recent year of data is reasonable to forecast its superannuation adjustment. We have included the superannuation adjustment in our substitute estimate for capex.[247]

245 SA Power Networks, *Information Request 18*, 16 April 2019, p. 2.

246 SA Power Networks, *2020–25 Regulatory Proposal – attachment 5 – Capital Expenditure*, January 2019, p. 112.

247 The difference between the amount included in our substitute estimate and SA Power Networks' forecast relates to modelling adjustments, which are discussed in section A.1.2 of this attachment.

B Engagement and information-gathering process

Proposal

SA Power Networks lodged its revenue proposal on the 31 January 2019. The proposal included a capex attachment, which provided a high-level view of the SA Power Networks' capex forecast. In addition, SA Power Networks provided a set of supporting documentation, such as its repex overview document, a sample of business cases, which related to augex and ICT, its capex model and its Strategic Asset Management Plan (SAMP).

Information-gathering process

To gain a better understanding of SA Power Networks' proposal, we requested further material through our requests for information process. We sent SA Power Networks 40 information requests. These included 4 information requests prepared by our consultant, EMCa. SA Power Networks responded to all the information requests in a timely matter.

Engagement

We engaged with CCP14, ESCoSA and the Office of the Technical Regulator during the review process to understand and test their views on SA Power Networks' capex proposal. We had regard to their views and their public submissions, when provided, along with all the other submissions that we received on SA Power Networks' capex proposal.

In terms of engagement with SA Power Networks, below we note the interactions we have had with SA Power Networks in the lead up to draft determination.

Pre-proposal stage

- we attended the 'deep dives', which allowed us to gain a greater understanding of SA Power Networks' capex proposal.
- we had a repex modelling meeting in December 2018, where we explained our repex modelling technique, and the rationale underpinning our latest decisions.
- we met with SA Power Networks to understand the underlying assumption underpinning its CRBM modelling.

During the review period

In mid-May, we had an on-site discussion with SA Power Networks and EMCa in Adelaide, where we sought further detailed information on capex issues and tested our understanding of SA Power Networks augex, ICT and repex proposals. EMCa's assessment is based on its observation from the on-site meetings, together with the information supplied prior to, at, and following the on-site discussion.

In early May 2019, we provided SA Power Networks a copy of its preliminary repex modelling results, which outlined the modelling assumptions and results. In response to the results, SA Power Networks sent us a letter outlining its view and position on our underlying assumptions and modelling. We have carefully considered SA Power Networks' position and provided SA Power Networks with the AER position in late July 2019. We have outlined that we agreed with an element of SA Power Networks' position, but disagreed with others.[248] We explained the basis and the rationale of our decision.

In June 2019, we held in-depth discussions with SA Power Networks where we outlined information gaps in its proposal and SA Power Networks agreed to provide new information with its revised proposal. We also conducted an in depth discussion on our methodology for assessing fleet capex. This included providing SA Power Networks with our bottom up adjustments to its fleet model.

Similarly, in July 2019, we met with SA Power Networks and provided it with an early indication of our assessment of its capex drivers. In our discussion, we provided our assessment of SA Power Networks' capex proposal, which lacked justification for the observed step-up. We provided SA Power Networks with an early indication of the likely draft decision reduction and the basis of our decision, which was consistent with EMCa's draft findings of SA Power Networks governance, forecasting methodology and its sample bottom-up assessment of SA Power Networks' repex, augex and ICT.

[248] Our response to SA Power Networks' letter on repex modelling is discussed in Appendix C of this draft decision.

C Repex modelling considerations

In May 2019, we provided SA Power Networks' preliminary modelling results, which detailed the classification between modelled and unmodelled as described in Table 5.6 of this attachment. In response, SA Power Networks sent a letter highlighting its concerns. SA Power Networks disagreed with four of our assumptions:

- The exclusion of poles from modelled repex.
- The modelling of 66 kV Gas Insulated Switchboard.
- The blending of replacement and refurbishment for transformers and switchgear.
- The exclusion of unique asset categories.

Each of those issues are discussed in turn below.

The exclusion of poles

SA Power Networks submitted in a letter that poles should be included as a component of the modelled repex assessment.[249] It contended that when compared to other pole types (concrete, steel and wood), their blended unit cost is lower than the NEM median blended unit cost for all other pole types and have a comparatively long life relative to concrete and steel poles.[250] SA Power Networks acknowledge that Stobie poles are unique in construction, but argue that for consistency with other distributor repex threshold determinations it would be grossly inequitable to exclude poles from the modelled repex threshold determination.[251] Subsequent to this letter, we received a second, which stated if it could be demonstrated that the Stobie pole is not materially unique from a modelling perspective, the AER repex model could be utilised as a comparator.[252]

We have considered SA Power Networks' letter and have not included Stobie poles as part of modelled repex for the following reasons:

- Stobie poles are unique with no other business with these types of assets in their network. Following our refinements to the repex model where the unit costs and replacement volumes of NEM businesses can be compared, it is important to ensure comparisons can be made on a like-for-like basis. Comparing Stobie poles

249 SA Power Networks, *Letter - AER preliminary repex modelling results for SA Power Networks*, public, 21 June 2019.

250 When an unstaked/unplated pole needs to be replaced, there are two appropriate unit costs – the cost of installing a new pole and the cost of staking/plating the existing. A weighted average is used, where the proportion of a networks propensity to replace and the proportion of the networks propensity to stake, and the unit cost of pole replacement and the unit cost staking are used to arrive at a blended unit cost. SA Power Networks, Letter - AER preliminary repex modelling results for SA Power Networks, public, 21 June 2019, p. 2.

251 SA Power Networks, *Letter - AER preliminary repex modelling results for SA Power Networks*, public, 21 June 2019, p. 3.

252 SA Power Networks, *Letter - Forecast Replacement Capital Expenditure*, public, 12 August 2019, p. 3.

with other poles would result in a non like-for-like comparison. Our position to exclude Stobie poles from modelled repex is consistent with our recent Evoenergy 2019–24 and Ausgrid 2019–24 determinations, where we excluded from the modelled component of repex their unique fibreglass poles and 132 kV underground cable assets, respectively.

- SA Power Networks' analysis highlighted that expected lives and unit costs of Stobie poles are lower than the blended lives and costs for steel, wood and concrete pole types. We have considered SA Power Networks' analysis and concluded that it is not comparing like for like. In particular, SA Power Networks states that Stobie poles has a comparatively long life relative to concrete and steel,[253] however, the inferred expected lives is comparing non-plated steel or non-plated concrete to plated Stobie poles, which would naturally have a relatively longer lives. As such, it is apparent that SA Power Networks is not comparing like for like.
- The RIN separates poles into the defined categories based on their material composition; wood, steel and concrete. To include Stobie poles within the poles category would introduce an inconsistency into the RIN reporting, which SA Power Networks has itself excluded from the poles category since 2008.
- While SA Power Networks has submitted it would be inequitable to exclude poles from the modelled component of repex based on their uniqueness, it would be inequitable to other distributors for wooden poles to be compared to SA Power Networks' Stobie poles which exhibit longer lives, have a different asset management strategy and can be re-plated after an initial plating.

It is important to note that irrespective of whether a particular asset group is considered modelled repex or unmodelled repex, we expect distributors to provide robust cost-benefit analysis to support their repex. Our bottom-up review of SA Power Networks' CBRM poles modelling is discussed in Appendix A.

The modelling of 66 kV Northfield Gas Insulated Switchboard

SA Power Networks noted the uniqueness of the Gas Insulated Switchboard and that its investment needs are different to its business as usual expenditure inputs used for repex modelling. SA Power Networks submitted that given the nature and criticality of the project, it should be proposed as a special project under the ‘Other’ repex asset group, with its own bottom-up cost estimate.[254] We agree with SA Power Networks’ rationale in this instance and have excluded the project from the repex modelling.

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[253] SA Power Networks, *Letter - AER preliminary repex modelling results for SA Power Networks*, public, 21 June 2019, p. 2.

[254] SA Power Networks, *Letter - AER preliminary repex modelling results for SA Power Networks*, public, 21 June 2019, p. 6.

The blending of replacement and refurbishment for transformers and switchgear

SA Power Networks contended that its reporting practice, for transformers and switchgear, differs from other distributors, as SA Power Networks reports refurbishment separately to differentiate it from replacement, with the result being that SA Power Networks' switchgear and transformers unit rates are not comparable to the NEM median.[255] SA Power Networks believes that the application of an asset-category based 'blended' intervention type from reported refurbishments and replacements does not provide for comparable benchmarking against other distributors nor an appropriate measure for repex modelling.[256] SA Power Networks strongly believes historical replacement volumes/expenditures alone to be more appropriate to modelling the repex requirements across these asset classes.[257]

We considered SA Power Networks' response and identified that the blending of refurbishment and replacement did not make a material difference on the repex modelling results, except for 11 kV circuit breakers category. For this category, without including refurbishment volumes and expenditure, SA Power Networks' unit costs are over 4.5 times greater than the NEM median. However, when we ran the repex model with blended refurbishments and replacements, the unit costs were more comparable with other distributors and closer to the NEM median. This result suggests that other distributors are more commonly blending their refurbishment and replacement costs, and it would be unreasonable to exclude refurbishment costs.

The exclusion of unique asset categories

SA Power Networks submitted that three of its transformer asset categories are reported under user-defined as they were not available within the AER defined transformer categories.[258] SA Power Networks submitted that these categories are not unique and recommended taking them into account in our repex modelling of the transformer asset group.[259] We have reviewed SA Power Networks' views and observed that SA Power Networks was the only distributor that reported these asset categories, as such, we were unable to compare them to other distributors' unit costs and expected replacement lives. Consistent with the approach for Stobie poles, we excluded these categories from the repex modelling to ensure comparisons are made on a like-for-like basis.

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[255] SA Power Networks, *Letter - AER preliminary repex modelling results for SA Power Networks*, public, 21 June 2019, p. 6.

[256] SA Power Networks, *Letter - AER preliminary repex modelling results for SA Power Networks*, public, 21 June 2019, p. 7.

[257] SA Power Networks, *Letter - AER preliminary repex modelling results for SA Power Networks*, public, 21 June 2019, p. 7.

[258] The categories are transformers that are kiosk mounted; > 22 kV; > 60 kVA and < = 600 kVA, pole mounted; > = 22 kV & < = 33 kV; < = 60kVA and pole mounted; > = 22 kV & < = 33 kV; < = 60kVA.

[259] SA Power Networks, *Letter - AER preliminary repex modelling results for SA Power Networks*, public, 21 June 2019, p. 8.

D Demand

Maximum demand forecasts are fundamental to a distributor's forecast capex and opex, and to our assessment of that forecast expenditure. We must determine whether the capex and opex forecasts reasonably reflect a realistic expectation of demand forecasts.[260] Hence accurate, or at least unbiased, demand forecasts are important inputs to ensuring efficient levels of investment in the network.

D.1 Draft decision

SA Power Networks has established that its demand forecast reflects a realistic expectation of demand over the 2020–25 period. We have identified that SA Power Networks' forecast peak demand growth of 0.4 per cent per annum is below the Australian Energy Market Operator's (AEMO) forecast of 0.6 per cent per annum over the 2020–25 period. In addition, SA Power Networks applies spatial demand forecasting methodologies that appear to be broadly consistent with AEMO's approach to forecasting demand at transmission connection points. We also recognise that the spatial peak demand forecasts do not result in any significant augmentation plans for either zone substations or connection points.[261]

D.2 SA Power Networks' proposal

SA Power Networks forecasts system peak demand to grow at 0.4 per cent per annum in the 2020–25 period. It is relatively flat compared with historic fluctuations, with the system reaching record levels of peak demand at about 2,900MW in the summers of 2009, 2010, 2011 and 2014. The temperature corrected peak demand at 50 per cent probability of exceedance (POE) is forecast to grow from 2,620MW in 2018–19 to 2,678MW in 2024–25.[262] Figure 5.17 shows SA Power Networks' historical coincident summer peak demand actuals and forecast.

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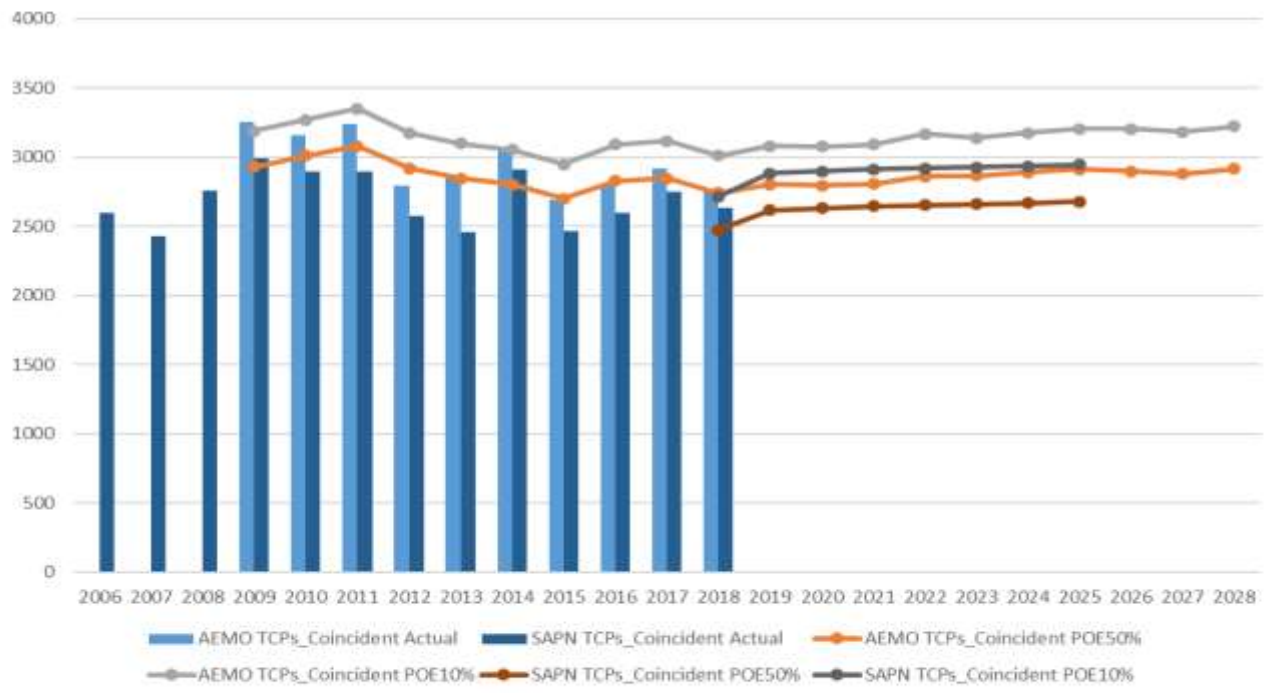
260 NER, cll. 6.5.6(c)(3) and 6.5.7(c)(1)(iii).

261 SA Power Networks, *Information Request 25 - Demand forecast*, 9 May 2019, p. 2.

262 POE demand is the probability or likelihood the forecast would be met or exceeded. The 10 per cent POE forecast is likely to be met or exceeded one year in 10, so considers more extreme weather conditions than a 50 per cent POE forecast, which is expected to be met or exceeded one year in two.

Figure 5.17 SA Power Networks and AEMO coincident summer peak demand actuals forecasts from 2006–2028 (MW)



Sources: SA Power Networks RIN responses and the AEMO forecasting data panel.

D.3 Reasons for draft decision

Our review of SA Power Networks' demand forecasting methodology identified SA Power Networks has reconciled its bottom-up connection point forecasts with AEMO's South Australia system demand forecast trend.[263] The common trend shared by the two sets of system peak demand forecasts reflects the impact of those economic, demographic, and other factors as captured and estimated in the AEMO forecasts. Figure 5.17 shows that SA Power Networks and AEMO both forecast a similar trend in peak demand growth.

In addition, SA Power Networks applies spatial demand forecasting methodologies that appear to be broadly consistent with AEMO's approach to forecasting demand at transmission connection points.[264] SA Power Networks and AEMO undertake the same process of econometric modelling and simulation, combined with pre- and post-modelling adjustments for some distributed energy resources and block loads, to derive temperature-corrected peak demand at alternative POE levels.

[263] AEMO, *Electricity Statement of Opportunities*, 2018.

[264] ACIL Allen, *Methodology and Users Guide for SA* Power Networks *Maximum Demand Forecasting Tool*, Report to SA Power Networks, August 2014; ACIL Allen, *Connection Point Forecasting – A Nationally Consistent Methodology for Forecasting Maximum Electricity Demand*, Report to Australian Energy Market Operator, 26 June 2013.

E Ex post statement of efficiency and prudency

We are required to provide a statement on whether the roll forward of the regulatory asset base from the previous period contributes to the achievement of the capital expenditure incentive objective.[265] The capital expenditure incentive objective is to ensure that, where the regulatory asset base is subject to adjustment in accordance with the NER, only expenditure that reasonably reflects the capex criteria is included in any increase in the value of the regulatory asset base.[266] The NER require that the last two years of the current regulatory control period (2018–19 and 2019–20) are excluded from past capex ex-post assessment.[267] Accordingly, our ex-post assessment only applies to the 2015–16, 2016–17 and 2017–18 regulatory years.

The NER states that we may only make a determination to reduce inefficient past capex if any one of the following requirements is satisfied:

1. the distributor has spent more than its capex allowance (the 'overspending' requirement)
2. the distributor has incurred capex that represents a margin paid by the distributor, where the margin referable to arrangements that, in our opinion, do not reflect arm's length terms (the 'margin' requirement)
3. where the distributor's capex includes expenditure that should have been treated as opex (the 'capitalisation' requirement).[268]

E.4 Draft decision

We are satisfied that SA Power Networks’ capital expenditure in the 2015–16, 2016–17 and 2017–18 regulatory years should be rolled into the RAB.

E.5 Reasons for draft decision

We have reviewed SA Power Networks' capex performance for the 2015–16, 2016–17 and 2017–18 regulatory years. This assessment has considered SA Power Networks' actual capex relative to the regulatory allowance given and the incentive properties of the regulatory regime for a distributor to minimise costs. SA Power Networks' incurred total capex below its forecast regulatory allowance in 2015–16, 2016–17 and 2017–18.

We have also had regard to some measures of input cost efficiency as published in our latest annual benchmarking report.[269] We recognise that there is no perfect

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265 NER, cl. 6.12.2(b).

266 NER, cl. 6.4A(a).

267 NER, cl. S6.2.2A(a1).

268 NER, cl. S6.2.2A(b) to (i).

269 AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2018.

benchmarking model, but we consider that our benchmarking models are robust measures of economic efficiency and we can use this measure to assess and compare a distributor's efficiency.

The results from our most recent benchmarking report shows that SA Power Networks has retained its position as the second most efficient distributor out of the thirteen NEM distributors with a multilateral total factor productivity (MTFP) score of 1.304 for 2017. However, it must be noted that this represents a six per cent decrease from its MTFP score of 1.391 for 2016.[270] The sharp decrease in productivity in 2017 did arise after two years of consecutive productivity growth in 2015 and 2016.[271] While this provides relevant context, we have not used our benchmarking results in a determinative way for this capex draft decision, including in relation to this ex-post prudency and efficiency review.

We consider that the 'overspending' and 'margin' requirements are not satisfied.[272] However, we consider that SA Power Networks has satisfied the 'capitalisation' requirement. During our review, SA Power Networks informed us that it had incurred capex of around $39.7 million in the current period that, according to its capitalisation policy, should have been classified as opex. SA Power Networks submitted that this change is not resulting from an accounting policy change, rather correcting an accounting error as these costs better represent general maintenance and emergency repairs.[273] We investigated this expenditure and find that:

- The incurred expenditure does not appear to be included in SA Power Networks' opex allowance for 2015–20, therefore, it would be unreasonable to penalise SA Power Networks, by treating that expenditure as opex for the purpose of calculating the EBSS carryovers.
- Similarly, as the amount was included in SA Power Networks' capex allowance for 2015–20, it would be unreasonable to exclude it from SA Power Networks' RAB, as SA Power Networks has treated it as such throughout the regulatory control period.

Our analysis suggests that there has not be any consumer detriment as a result of capitalising this expenditure. Therefore, we do not consider that it is necessary to remove this expenditure from the RAB.

For the reasons set out above, we are satisfied that the entirety of SA Power Networks' capital expenditure in the 2015–16, 2016–17 and 2017–18 regulatory years should be rolled into the RAB

270 AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2018, pp. 13.

271 AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2018, pp. 18.

272 NER, cl. S6.2.2A(c).

273 SA Power Networks, *Information Request 04 - Various categories and capex reconciliation*, 22 February 2019, p. 3.

F Contingent project

Contingent projects are significant network augmentation projects, of uncertain timing. Contingent projects' capex does not form a part of our assessment of the total forecast capex that we approve in this determination. However, they are linked to unique investment drivers (rather than general investment drivers such as expectations of load growth in a region) and are triggered by a defined 'trigger' event. The occurrence of the trigger event must be probable during the relevant regulatory control period.[274]

If, during the regulatory control period, SA Power Networks considers that a trigger event has occurred, then it may apply for additional revenue. At that time, we will assess whether the trigger event has occurred and whether the project meets the threshold of, $30.0 million or, 5 per cent of the annual revenue requirement in the first year of the 2020–25 regulatory control period. If both conditions are satisfied, we will determine the efficient incremental revenue that is likely to be required in each remaining year(s) of the regulatory control period as a result of the contingent project, and amend the revenue determination accordingly.[275]

F.1 Draft decision

SA Power Networks has not demonstrated that its proposed electricity system security is reasonably required to achieve the capex objectives. SA Power Networks' trigger is reasonable. However, SA Power Networks has not satisfied us that its proposed contingent project capex is prudent and efficient.

SA Power Networks has submitted that it identified this contingent project shortly before it submitted its regulatory proposal. We acknowledge that, at the time, it may have limited information. However, to date, we have not received sufficient information that supports the proposed contingent project capex. Although SA Power Networks considers this contingent project capex is required to respond to a regulatory obligation, there is no indication of the requirements of this regulatory obligation. SA Power Networks may comply with its regulatory obligations through a pass through.

F.2 Assessment approach

We reviewed SA Power Networks' proposed contingent project against the NER requirements.[276] We considered whether:

- the proposed contingent project is reasonably required in order to achieve any of the capex objectives.[277]

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274 NER, cl. 6.6A.1 (5).

275 NER, cl. 6.6A.2.

276 NER, cl. 6.6A.1.

277 NER, cl. 6.6A.1.

- the proposed contingent project capital expenditure is not provided for elsewhere in the capex proposal.[278] Most relevantly, a distributor must include forecast capex in its revenue proposal which it considers is required in order to meet or manage expected demand for standard control services over the regulatory control period.[279]
- the proposed contingent project reasonably reflects the capex criteria, taking into account the capex factors.[280] Importantly this requires the expenditure to be efficient.
- the proposed contingent project capital expenditure exceeds the defined threshold.[281]
- the trigger events are appropriate. This includes having regard to the need for the trigger event:
    i. to be reasonably specific and capable of objective verification.[282]
    ii. to be a condition or event which, if it occurs, make the project reasonably necessary in order to achieve any of the capex objectives.[283]
    iii. to be a condition or event that generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the distribution network as a whole.[284]
    iv. is described in such terms that it all that is required for the revenue determination to be amended.[285]
    v. is probable during the 2015–20 regulatory control period but the inclusion of the project in the total forecast capex is not appropriate because either it is not sufficiently certain that the event or condition will occur during the regulatory control period; or the costs associated with the event or condition are not sufficiently certain.[286]

We also considered the interaction between the total forecast capex included in our revenue determination and projects proposed as contingent projects. Where a project is included in total forecast capex, it cannot also be included as a contingent project.[287] Further, the case for a contingent project needs to take into account the extent to which the forecast capex in included in our revenue determination already caters for increased demand across the network.

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278 NER, cl. 6.6A.1(b)(2)(i).
279 NER, cl. 6.5.7(a)(1).
280 NER, cl. 6.6A.1(b)(2)(ii).
281 NER, cl. 6.6A.1(b)(2)(iii).
282 NER, cl. 6.6A.1(c)(1).
283 NER, cl. 6.6A.1(c)(2).
284 NER, cl. 6.6A.1(c)(3).
285 NER, cl. 6.6A.1(c)(4).
286 NER, cl. 6.6A.1(c)(5).
287 NER, cl. 6.6A.1(b)(2)(i).

F.3 SA Power Networks' proposal

SA Power Networks' proposed electricity system security project of $79.2 million to implement changes to the existing under frequency load shedding (UFLS) scheme and/or implement additional measures as required by AEMO to maintain security of supply within South Australia during the 2020–25 regulatory control period.

F.3.1 Proposed triggers

The updated triggers, which SA Power Networks' revised after it submitted its proposal, are:

1. SA Power Networks receives a notification from AEMO requiring SA Power networks to implement any of:

   (a) changes to, or in connection with, any emergency frequency control scheme

   (b) any other measures that AEMO determines are required to ensure AEMO's continued ability to maintain security and reliability of supply within South Australia with increasing levels of distributed energy resources, in a timeframe that necessitates investment within the 2020–25 regulatory control period, where those changes or measures are required at or in relation to any of:

   - one of more specific zone substations (e.g. UFLS relays)
   - central systems that control any UFLS scheme
   - systems to control specific large-scale embedded generators
   - any combination of the above.[288]

2. Successful completion of the Regulatory Investment Test–Distribution, or an equivalent economic evaluation, in relation to the required investment including an assessment of credible options and the identification of the preferred option.
3. SA Power Networks' Board commitment to proceed with the project, subject to the AER amending the distribution determination for the 2020–25 regulatory control period pursuant to the NER.

F.3.2 Proposed project scope

SA Power Networks' proposed contingent project capex to re-design and re-build the existing UFLS scheme and also to establish a capability to shed DER.

In order to re-design and re-build the existing UFLS scheme, SA Power Networks proposed to replace and recommission 625 existing under frequency protection relays with units that support load flow determination and the ability to selectively enable under-frequency operation. This would build additional capability in its distributed control system and would enable SA Power Networks to determine the volume and

288 SA Power Networks, *Information Request 47*, June 2019, pp. 1–2.

direction of load flow on a given feeder before the control system automatically disconnects, should the frequency drop below the specified level.

In order to establish the capability to shed DER, SA Power Networks considers that AEMO may require it to establish a central control system to coordinate embedded generation output. SA Power Networks may be required to disconnect or reduce the output of DER in a controller manner so as to achieve a target reduction in the power output of distributed generators, particularly in the event where South Australia is separated from the national electricity grid.

SA Power Networks also considers AEMO may require SA Power Networks to undertake unforeseen additional works. SA Power Networks acknowledged that it had not consulted with stakeholders as it became aware of the possibility of this change a month before its submission of the regulatory proposal.

F.4 Reasons for draft decision

In coming to our decision, we have assessed the triggers and the proposed contingent capex under the capex criteria. We have also had regard to public submissions, such as CCP14, SACOSS and Business SA, who all discussed the proposed contingent project.[289] We discuss our assessment in turn below.

F.4.1 Assessment of triggers

SA Power Networks' updated triggers are reasonable. Initially, we had two concerns with SA Power Networks' proposed trigger. Firstly, it did not include a time frame.[290] Secondly, it did not refer to a condition or event that generates increased costs or categories of costs that relate to a specific location rather than a condition or even that affects the distribution network as a whole.[291] However, in response to an information request detailing our concerns, SA Power Networks' amendments addressed the timing and location concerns.

F.4.2 Assessment of capex

SA Power Networks' proposed contingent project capex is not prudent and efficient, as it does not meet the capex criteria. SA Power Networks' proposal assumed that AEMO will place a regulatory obligation on it to be compliant with an updated UFLS scheme. However, in response to our information requests for formal correspondence between SA Power Networks' and AEMO, SA Power Networks stated:

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289 CCP14, *Advice to the AER on the SA Power Networks 2020–25 regulatory proposal*, May 2019, p. 43, SACOSS, *Submission in response to AER Issues Paper on the SA Power Networks electricity determination 2020–2025*, May 2019, p.9, Business SA*, Submission to AER on SA Power Networks 2020–25 regulatory proposal (including tariff structure statement)*, May 2019, p. 7.

290 NER, cl. 6.6A.1(c)(5).

291 NER, cl. 6.6A.1(c)(3).

> At this stage we do not have formal correspondence from AEMO that directs us to implement the changes we have considered in our contingent project.[292]

Although we recognise that the issues raised by SA Power Networks may require changes to UFLS scheme, the obligation is not certain. SA Power Networks' expected changes in the UFLS may not necessarily reflect actual changes to its regulatory obligations. For example, our review has identified that the AEMO's 2018 Power System Frequency Risk Review Report examined the UFLS in South Australia and has concluded that the present UFLS settings are adequate and has not identified any need to modify this scheme.[293] Therefore, the obligation is not certain.

SA Power Networks proposed capex is not efficient, SA Power Networks has not considered alternatives to addressing potential UFLS issues as its analysis is a work in progress.[294] The CCP also raised similar concerns in regards to use of alternatives.[295] As SA Power Networks has not undertaken an option analysis, or a cost benefit analysis, it is unlikely that its proposed capex is the most efficient option.

In addition, as SA Power Networks has proposed several DER management related project, which are discussed in A.2 of this capex attachment, SA Power Networks has not considered the holistic approach to addressing changes to the UFLS scheme and possible interactions with other DER management projects to arrive at a least cost option to meet its regulatory obligations. SACOSS also considered there seemed to be overlap with other capex programs.[296]

Lastly, the driver of this contingent project is an expected change in regulatory obligation, adjustments can be made to a building block determination for a cost pass through due to a regulatory change event.[297]The materiality threshold for a pass through event is one per cent of annual revenue for that year.[298] As the proposed capex meets the contingent project threshold of $30.0 million or five per cent of the value of the first year annual revenue requirement, the costs proposed by SA Power Networks would also meet the threshold for a cost pass through event.

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[292] SA Power Networks, *Information Request 28*, May 2019, p. 1.

[293] AEMO, Power System Frequency Risk Review Report, June 2018, p. 31.

[294] SA Power Networks, *Information Request 28*, May 2019, p. 2.

[295] CCP14, *Advice to the AER on the SA Power Networks 2020–25 regulatory proposal*, May 2019, p. 43, SACOSS, *Submission in response to AER Issues Paper on the SA Power Networks electricity determination 2020–2025*, May 2019, p.9

[296] SACOSS, *Submission in response to AER Issues Paper on the SA Power Networks electricity determination 2020–2025*, May 2019, p.9.

[297] NER, cl. 6.6.1(a1)(1).

[298] NER, Chapter 10: Glossary, definition of 'materially'.