DRAFT DECISION

Ergon Energy
Distribution determination
2020–21 to 2024–25

Attachment 5
Capital expenditure

October 2019

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to Ergon Energy for the 2020–2025 regulatory control period. It should be read with all other parts of the draft decision, which includes the following documents:

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

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Contents

Shortened forms

Shortened form	Extended form
ADMS	advanced distribution management system
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP14	Consumer Challenge Panel (sub-panel 14)
CESS	capital expenditure sharing scheme
DER	distributed energy resources
DSO	distribution system operator
EBSS	efficiency benefit sharing scheme
FPSC	fixed price service charge
ICT	information and communications technology
MEFM	Monash Electricity Forecast Model
MW	megawatt
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	net present value
NSP	network service provider
RAB	regulatory asset base
repex	replacement expenditure
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	supervisory control and data acquisition
STPIS	service target performance incentive scheme

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. Further detailed analysis of our draft decision is provided in the following appendices:

- Appendix A – Capex driver assessment
- Appendix B – Engagement process and data discrepancies
- Appendix C – Forecast demand
- Appendix D – Ex-post prudency and efficiency review.

We have based our draft decision on our analysis of the information we have received to date. Ergon Energy's revised proposal, submissions and further analysis will inform our final decision in April 2020. All dollar amounts are presented in real \$2019–20 unless otherwise noted.

5.1 Draft decision

We do not accept Ergon Energy's capex forecast, as it has not satisfied us that its total net capex forecast of \$2724.2 million reasonably reflects the capex criteria. Our substitute estimate of \$2150.9 million is 21 per cent below Ergon Energy's forecast. We

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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 – Ergon Energy distribution determination 2020–25 – AER capital expenditure assessment outline,* October 2019.

are satisfied that our substitute estimate reasonably reflects the capex criteria. Our substitute estimate will allow Ergon Energy to maintain the safety, service quality and reliability of its network, consistent with its legislative obligations. Table 5.1 outlines our draft decision.

Table 5.1 – Draft decision on Ergon Energy's total net capex forecast ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Ergon Energy's proposal	528.3	540.9	560.0	545.4	549.6	2,724.2
AER draft decision	421.6	432.6	434.2	424.2	438.3	2.150.9
Difference ($)	-106.7	-108.3	-125.8	-121.2	-111.3	-573.3
Percentage difference (%)	-20%	-20%	-22%	-22%	-20%	-21%

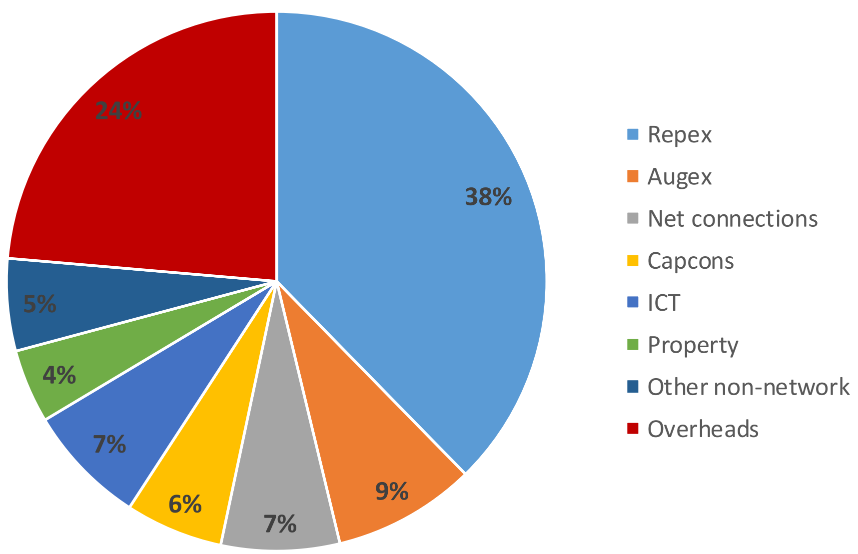
Source: Ergon Energy's PTRM and AER analysis.

Note: 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 Ergon Energy's proposal

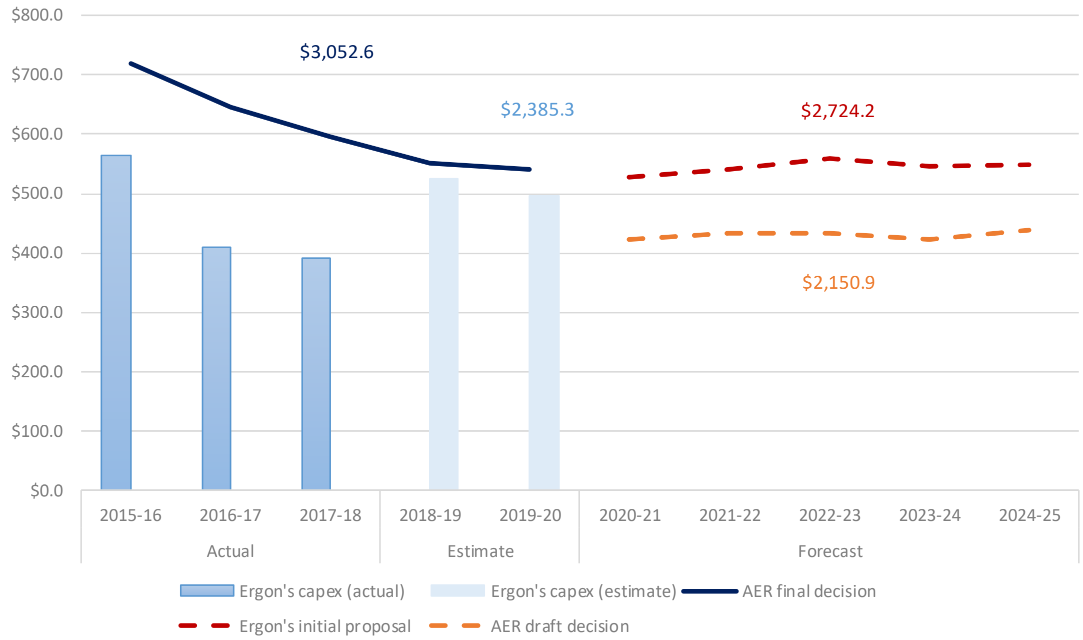
For the 2020–25 regulatory control period, Ergon Energy proposed forecast net capex of $2724.2 million. Ergon Energy's forecast is $339.0 million (14 per cent) higher than it actual and estimated capex of $2385.3 million over the 2015–20 regulatory control period. Figure 5.2 outlines Ergon Energy's historical capex performance against its capex forecast.

Figure 5.1 – Ergon Energy's total gross capex forecast ($ million, 2019–20)



Source: Ergon Energy's reset RIN and AER analysis.

Figure 5.2 – Ergon Energy's historical vs forecast capex snapshot ($ million, 2019–20)



Source: AER analysis.

Note: Ergon Energy's actual and estimated capex is based on Ergon Energy's recast category analysis RIN data that reflects Ergon Energy's new CAM that will apply for the 2020–25 regulatory control period. The 2015–20 AER final decision allowance therefore not directly comparable with the historical and forecast capex amounts shown.

Recast historical data discrepancies

During our assessment of Ergon Energy's proposal, we discovered significant data reporting discrepancies between its recast historical expenditure data and its original historical expenditure data. We have engaged with Ergon Energy extensively throughout the course of our assessment to understand why the two data sets do not reconcile. Appendix B outlines our engagement with Ergon Energy and also provides a detailed explanation of the data discrepancies we have identified. Having clear and consistent data sources is crucial for stakeholders to develop a full and accurate understanding of a distributor's capex forecast.

5.3 Reasons for draft decision

Ergon Energy has not demonstrated that its total capex forecast reasonably reflects the capex criteria. We outline how we have applied our assessment techniques and how we came to our position in appendix A. We are required to set out a substitute estimate, which we are satisfied reasonably reflects the capex criteria. As part of our assessment, we engaged Energy Market Consulting associates (EMCa) to undertake a detailed review of Ergon Energy's total capex proposal. Overall, we agree with EMCa's conclusion that:

> EQ does not consistently apply the structural elements of its investment governance and management framework and forecasting processes to a

> standard that would achieve a capex forecast that is prudent, efficient and reasonable in accordance with the NER capex criteria. Its forecasting processes have led to a systemic bias to over-estimation in the forecast that it has proposed.[5]

Consistent with previous decisions, distributors generally provide material to demonstrate the prudency and efficiency of their capex forecasts. This includes risk-based cost-benefit analysis with all options considered, reasoning for the application of key inputs in the forecast, demonstration of a top-down challenge or forecast testing, and any other evidence that supports a rigorous forecasting methodology.

Overall, we observed a lack of necessary supporting material throughout Ergon Energy's capex proposal. There were also significant delays in receiving responses to information requests throughout the review process. However, we acknowledge that Ergon Energy engaged with us extensively ahead of our draft decision to discuss these information gaps. It provided additional supporting material, although this material still lacked the quantitative assessment we typically expect to support a capex forecast.

In forming its revised proposal, we encourage Ergon Energy to have regard to our observations throughout this draft decision, particularly where we have noted a lack of supporting material to justify the prudency and efficiency of its capex forecasts. Table 5.2 sets out the capex amounts by driver that we have included in our substitute estimate of Ergon Energy's total capex forecast for the 2020–25 regulatory control period. The reasons for our substitute estimate of $2150.9 million are summarised by capex driver below.

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

Driver	Ergon Energy's proposal	Draft decision	Difference ($)	Difference (%)
Augex	248.5	170.5	-78.0	-31%
Gross connections	375.9	375.9	0.0	0%
Repex	1094.4	842.0	-252.4	-23%
ICT capex	210.1	159.7	-50.4	-24%
Property capex	128.6	56.5	-72.0	-56%
Other non-network capex	160.7	137.5	-23.1	-14%
Capitalised overheads	686.5	613.9	-72.6	-11%
Gross capex	**2904.7**	**2356.1**	**-548.6**	**-19%**
less capital contributions	169.9	169.9	0.0	0%
less asset disposals	10.6	19.3	8.7	82%

5 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure*, August 2019, p. i.

Driver	Ergon Energy's proposal	Draft decision	Difference ($)	Difference (%)
less modelling adjustments	-	16.1	-	-
Net capex	**2724.2**	**2150.9**	**-573.3**	**-21%**

Source: Ergon Energy's capex model and AER analysis.

Note: Numbers may not sum due to rounding. Modelling adjustments relate to Ergon Energy's CPI and real price escalation assumptions. Gross capex is presented before any modelling adjustments are applied.

Table 5.3 summarises our findings and the reasons for our draft decision by capex driver (e.g. augmentation, replacement, connections etc.). This reflects the way we have assessed Ergon Energy's total capex forecast. Our findings on the capex drivers are part of our broader analysis and should not be considered in isolation. We do not approve an amount of forecast expenditure for each individual capex driver. 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 Ergon Energy's proposal, such as augmentation, replacement, ICT capex and property capex, 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 forms part of an overall distribution determination that is likely to contribute to the achievement of the NEO to the greatest degree.

Table 5.3 – Summary of our findings and reasons

Issue	Reasons and findings
Total capex	Ergon Energy's governance and management framework led to a significantly overstated total capex forecast. Ergon Energy has applied its forecasting methodology inconsistently and many programs and projects lack sufficient risk-based cost-benefit analysis.
Augex	Ergon Energy proposed several sub-transmission growth projects, including projects to meet its Safety Net reliability obligations. For some projects, we found that more efficient solutions are available or that the capex is not required for Ergon Energy to fulfil its obligations. In addition, Ergon Energy has not demonstrated the need for several

6 NER, cll. 6.5.7(c), (d).

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

Issue	Reasons and findings
	projects.
Connections capex	Ergon Energy's forecast for new connections volumes is consistent with two independent housing forecasts and its unit costs are lower than its actual unit costs in the current period.
Repex	Ergon Energy's modelled repex is significantly greater than our predictive modelling threshold and its historical expenditure. Our bottom-up assessment also highlighted that Ergon Energy does not undertake risk-based cost-benefit analysis and its qualitative risk framework does not establish that its proposed investments are prudent and efficient. Ergon Energy also has not justified its LV safety program on economic or legislative grounds.
ICT capex	For recurrent ICT capex, we have accepted the proposal, with the exception of the proposed 'minor application upgrades and updates' expenditure. Ergon Energy did not provide sufficient evidence to justify this increased capex. For non-recurrent ICT capex, Ergon Energy has not demonstrated that the proposed program of works is deliverable over the 2020–25 regulatory control period. We have also removed Ergon Energy's forecast contingency costs when forming our substitute estimate, as customers should not bear these costs.
Property capex	Ergon Energy has not provided sufficient information to support its five major property projects or its physical security program. Ergon Energy has not adequately demonstrated need or has not undertaken a sufficient economic assessment to demonstrate the prudency and efficiency of its proposed works.
Other non-network capex	Other non-network capex includes fleet, plant, tools and equipment. Ergon Energy's service life and unit rate assumptions in Ergon Energy's fleet model exceed efficient costs. From a top-down perspective, there has been a downward trend in overall fleet, plant and equipment capex for Ergon Energy.
Capitalised overheads	We have applied a zero rate of change and adjusted the base year forecast to reflect our lower substitute of direct capex.
Asset disposals	Ergon Energy's proposal included an asset disposals forecast of $10.6 million for the 2020–25 regulatory control period. We asked Ergon Energy how this forecast was derived in an information request[8], and in response Ergon Energy "identified material issues" with its initial forecast.[9] It provided updated asset disposal forecasts in this response and we have used this information for the asset disposals amount used in our substitute estimate.

[8] AER, *Information request 54,* July 2019.

[9] Ergon Energy, *Response to information request 54,* July 2019.

Issue	Reasons and findings
Modelling adjustments	Our modelling adjustments relate to Ergon Energy’s CPI and real price escalation assumptions. We have updated the year-on-year CPI and real labour price escalation assumptions in Ergon Energy's capex model. These inputs are now consistent with other aspects of our decision. In addition, consistent with our standard approach, we have assumed no real price escalation for contracted labour. More information is provided in our draft decision capex model.

A Capex driver assessment

This appendix outlines our detailed analysis of Ergon Energy's capex category forecasts for the 2020–25 regulatory control period. These categories are augmentation capex (augex), connections capex, replacement capex (repex), ICT capex, property capex, other non-network capex, and capitalised overheads. All dollar amounts are presented in real $2019–20 unless otherwise noted.

We used various qualitative and quantitative assessment techniques to assess the different elements of Ergon Energy's 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.[10] In particular, we take into account whether our overall capex forecast will provide Ergon Energy 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.[11]

When assessing capex forecasts, we also consider:

- The prudency and efficiency criteria in the NER are complementary. Prudent and efficient expenditure reflects the lowest long-term cost to consumers to achieve the expenditure objectives.[12]
- Past expenditure was sufficient for the distributor to manage and operate its network in previous periods, in a manner that achieved the capex objectives.[13]
- The capex required to provide for a prudent and efficient distributor's circumstances to maintain performance at the targets set out in the STPIS.[14]
- The annual benchmarking report, which includes total cost and overall capex efficiency measures, and considers a distributor's inputs, outputs and its operating environment.
- The interrelationships between the total capex forecast and other constituent components of the determination, such as forecast opex and STPIS interactions.[15]

A.1 Total capex consideration

We received several submissions that focused on Ergon Energy's total capex trend and noted that forecast capex was higher than other networks. We received

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

11 NEL, s. 7A.

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

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

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

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

submissions from CCP14,[16] EnergyAustralia,[17] Origin Energy[18] and QCOSS[19] requesting we further examine many capex categories. Regarding Ergon Energy's total capex forecast, we also had regard to Ergon Energy's investment governance framework, approach to risk management and capex forecasting methodologies, which are discussed below.

Review of Ergon Energy's governance, risk management and expenditure forecasting

Our consideration of Ergon Energy's governance and risk management framework, and capital expenditure forecasting methods informed our assessment of its total capex forecast. As part of our assessment, we engaged EMCa to undertake a detailed review of Ergon Energy's repex and ICT capex forecasts. EMCa discovered 'systemic issues' with Ergon Energy's governance and management framework:

- Ergon Energy's optimisation process references the application of 'merger targets' in the development of a prudent and efficient level of expenditure. The application of such constraints and targets may not be consistent with the requirements of the NER.[20]
- Ergon Energy provided insufficient information and evidence of rigour to justify the proposed expenditure either for internal assessment or to external reviews, including a limited and poorly populated risk management framework.[21]
- Ergon Energy's forecasting processes have led to a systemic bias to over-estimation in the forecast that it has proposed.[22]
- A forecasting process designed to constrain expenditure levels to meet management-imposed constraints (such as a price outcome) may result in a network capex forecast that is either too high or too low. In either case, this approach is not fit-for-purpose and does not reflect demonstrated system needs.[23]

A.2 Augex

The need to build or upgrade the network to address changes in demand and network utilisation typically trigger augex. The need to upgrade the network to comply with quality, safety, reliability and security of supply requirements can also trigger augex.

A.2.1 Draft decision

Ergon Energy has not demonstrated that its augex forecast of $248.5 million is prudent and efficient. We have included $170.5 million for augex in our substitute estimate of

[16] CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 regulatory proposals,* May 2019.
[17] EnergyAustralia, *Submission on Ergon Energy's regulatory proposal 2020–25,* May 2019.
[18] Origin Energy, *Submission on Ergon Energy's regulatory proposal 2020–25*, May 2019.
[19] QCOSS, *Submission on Ergon Energy's regulatory proposal 2020–25,* May 2019.
[20] EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, p.18.
[21] EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, p. i.
[22] EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, p. i.
[23] EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, p. 22.

total capex. This is a reduction of $77.8 million (31 per cent). We consider this amount is prudent and efficient, and would form part of a total forecast capex allowance that reasonably reflects the capex criteria. Table A.1 summarises Ergon Energy's proposal and our substitute estimates by augex subcategory.

Table A.1 – Draft decision on Ergon Energy's total forecast augex ($ million, 2019–20)

Category	Proposal	Draft decision	Difference ($m)	Difference (%)
Subtransmission growth	65.2	42.4	-22.7	-35%
Distribution growth	95.6	95.6	0.0	0%
Network communications	69.6	19.1	-50.5	-72%
Power quality	13.8	9.2	-4.6	-33%
Worst performing feeders	4.1	4.1	0.0	0%
Total	248.3	170.5	-77.8	-31%

Source: Ergon Energy's proposal and AER analysis.

A.2.2 Ergon Energy's proposal

Ergon Energy forecast $248.5 million for augmentation expenditure for the 2020–25 regulatory control period. This represents a 31 per cent decrease relative to the $389.7 million that it expects to incur over the 2015–20 regulatory control period. It explained that augex is required to:[24]

- address key areas of community development, population and demand growth
- support the continued connection of residential and commercial solar PV systems to the distribution network
- maintain network statutory and standard requirements and address Distribution Authority obligations
- provide additional functionality to support an intelligent grid through a range of network control and monitoring initiatives.

A.2.3 Reasons for draft decision

We have reviewed Ergon Energy's augex proposal based on its classification of expenditure. Ergon Energy has not sufficiently justified the capex for the subtransmission network growth, network communications and power quality augex subcategories. In coming to our draft decision, we have assessed:

- the project documentation accompanying Ergon Energy's proposal and any further information it provided

[24] Ergon Energy, *2020–25 regulatory proposal*, January 2019, pp. 68–69.

- advice from engineering and technical experts
- stakeholder submissions including the Energy Consumers Australia (ECA) and CCP14.

Several small projects are not considered material relative to the augex proposal. For these projects, we have not conducted a detailed bottom-up assessment. Our assessment of each component of Ergon Energy's augex proposal is discussed below.

Subtransmission growth

Ergon Energy proposed $65.2 million for several subtransmission-level projects required to supply forecast loads and comply with regulatory obligations.

ECA's economic consultant Dynamic Analysis considered there may be opportunities to defer growth-related capex and suggested areas for review, including whether existing capacity from adjoining areas could be used to manage local constraints.[25]

We reviewed seven of the proposed projects, with a combined value of $54.8 million. Of the seven projects, four are driven by Safety Net obligations, which require Ergon Energy to restore supply within specified timeframes in the event of an outage. These projects include:

- Cannonvale & Jubilee Pocket 66kV reinforcement ($16.7 million)
- 66kV feeder from future Nikenbah BSP and Point Vernon ($7.9 million)
- Cloncurry supply reinforcement ($5.8 million)
- Planella reinforcement ($5.4 million).

The other three projects we reviewed are:

- Blackwater replacement and reinforcement ($7.5 million)
- Broxburn replacement and reinforcement ($6.3 million)
- East Bundaberg to Burnett Heads 66kV line build ($5.4 million).

Safety net driven projects

Ergon Energy explained that the primary driver of the following projects was its Safety Net obligation, which is a regulatory requirement and therefore a least-cost analysis is appropriate. It requires Ergon Energy to limit the amount of load without supply against predefined timeframes in the event of an outage. We have considered the respective projects against the Safety Net requirement to understand if there is a need to augment

Cannonvale & Jubilee Pocket 66kV Reinforcement

Ergon Energy proposed a package of line and substation works around Cannonvale zone substation to address supply reliability issues in the Airlie Beach region.[26] Ergon

[25] Dynamic Analysis, *Technical regulatory advice to the ECA – Review of 2020–25 regulatory proposals*, June 2019, pp. 43, 45.

Energy's cost-benefit analysis shows that the reduction of unserved energy is the main benefit.

While the benefit does not outweigh the cost over the 20 year assessment period, Ergon Energy is required to undertake some measure to ensure Safety Net compliance, and its preferred option would deliver the highest (least negative) NPV.[27]

Ergon Energy had regard to a reasonable range of options, including a base case and three network augmentation options.[28] We have included Ergon Energy's proposed capex for the Cannonvale and Jubilee Pocket 66kV reinforcement program in our substitute estimate.

66kV Feeder from Future Nikenbah BSP and Point Vernon

Ergon Energy proposed a second 66kV line to supply Point Vernon zone substation.[29] Point Vernon zone substation is currently supplied by a single feeder from Pialba zone substation. Ergon Energy's proposed new feeder would be built at the location of a future Nikenbah built supply point and connect to the existing 66kV Howard – Pialba M015 feeder.

Ergon Energy has demonstrated the need for a new feeder to ensure Safety Net compliance. Ergon Energy also considered the need to meet future demand by linking the feeder to a potential new bulk supply point. We considered whether a lower cost solution may be available to build a second line between Pialba and Point Vernon zone substations, but we recognise that the existing feeder runs through a residential area. There would be several barriers to build a new feeder at this location. We have included Ergon Energy's proposed capex for this project in our substitute estimate.

Cloncurry supply reinforcement

Ergon Energy proposed to address ground clearance compliance on a feeder (DR-CC-1 66kV), a contingent subtransmission supply from Chumvale zone substation serving the township of Cloncurry to address non-compliance with its Safety Net obligations in the event of a credible contingency.[30]

We have had regard to Ergon Energy's capacity to restore supply in compliance with its Safety Net obligation and do not consider that Ergon Energy has demonstrated the need for the proposed capex for the following reasons:

- Ergon Energy stated that it has completed a project WR994217 to install an additional generation point in Cloncurry to supplement the capacity of the DR-CC-1 line.[31] Given that Ergon Energy has already made this investment for a mobile

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26 Ergon Energy, *Planning proposal – Cannonvale and Jubilee Pocket*, January 2019, pp. 1–2.

27 Ergon Energy, *Cannonvale 66kV planning proposal V0.8a_NPV,* 21 March 2019.

28 Ergon Energy, *Planning proposal – Cannonvale and Jubilee Pocket*, January 2019, pp. 60–78.

29 Ergon Energy, *Planning proposal – Nikenbah to Point Vernon 66kV line augmentation,* 21 March 2019, pp. 1, 7.

30 Ergon Energy, *Cloncurry supply reinforcement planning proposal,* 21 March 2019, pp. 2–3.

31 Ergon Energy, *Cloncurry supply reinforcement planning proposal,* 21 March 2019, p. 28.

generator connection, it did not explain what prevented it from making use of this investment to meet its Safety Net obligations.

- It is unclear what constraints prevent Ergon Energy from dispatching and connecting mobile generation units within 18 hours, and to what extent it has explored alternative solutions that may reduce the dispatch time. We estimate that it would take 9 hours to transport a mobile transformer from Townsville to Cloncurry, within the 18 hour window to restore supply.
- Ergon Energy considered the main credible contingency as loss of a transformer at Chumvale zone substation.[32] Installing a new standby transformer at the substation may be a lower cost solution to meet the Safety Net obligation.

Therefore, we have not included Ergon Energy's proposed capex for Cloncurry supply reinforcement in our substitute estimate.

Planella reinforcement

Ergon Energy proposed to build a new 33kV line to from Glenella to Planella substations.[33] It explained that Planella zone substation currently supplied by one 33kV feeder and is non-compliant against the Safety Net criteria requirements in the event of a credible failure.

We requested supporting evidence and Ergon Energy provided information that explained that it had since replaced the previously preferred option with a more efficient alternative costed at $3.6 million.[34] We considered the information on expected restoration timeframes, and are satisfied that Ergon Energy has demonstrated non-compliance with its Safety Net requirement under a credible scenario. We have included Ergon Energy's revised estimate of $3.6 million in our substitute estimate.

Other subtransmission projects

Blackwater replacement and reinforcement

Ergon Energy proposed to upgrade 11/22kV power transformers with two 66/22kV transformers at Blackwater 132/66/22kV substation, which is a jointly owned facility of Ergon Energy and Powerlink.[35] It explained there are two primary drivers for the investment:

- Ergon Energy's primary plant and secondary systems at the substation are 40 years or older and near end of life, and several risks have been identified that are not as low as reasonably practicable (ALARP) that can be addressed.[36]

[32] Ergon Energy, *Cloncurry supply reinforcement planning proposal,* 21 March 2019, pp. 11, 27.
[33] Ergon Energy, *Subtransmission major project list*, January 2019, p. 15.
[34] Ergon Energy, *Response to information request 8,* 21 March 2019, p. 3.
[35] Ergon Energy, *Planning proposal – Blackwater substation refurbishment,* 21 March 2019, p. 1.
[36] Ergon Energy, *Planning proposal – Blackwater substation refurbishment,* 21 March 2019, p. 10.

- Powerlink is planning to replace two transformers in 2022 that will require Ergon Energy to reconfigure and uprate the 66kV transformer bay and to either reconnect tertiary supply or install 66/22kV transformers.

Ergon Energy proposes to maximise project efficiency by renewing the aged 66kV and 22kV substation assets and installing 66/22kV transformers in conjunction with Powerlink's associated works. Ergon Energy's cost-benefit analysis does not contain a base case and indicates an NPV negative outcome. Ergon Energy must demonstrate the outcome of the proposed asset replacement is NPV positive, because the primary driver is asset age rather than compliance with a specific regulatory obligation. [37] Ergon Energy could demonstrate the project is NPV positive by assessing the costs and benefits of the options it has considered relative to the base case of a no-replacement or do-nothing option.

Ergon Energy's risk assessment is qualitative, identifying risks in the low to moderate range, but because the risks have not been quantified, it cannot be applied in the NPV analysis to determine the merits of the proposed solution relative to the do-nothing option.[38] We discuss our concerns with Ergon Energy's use of qualitative risk assessment in section A.1.

Ergon Energy also proposed to replace assets that we provide an allowance for in our assessment of modelled repex, including transformers. An allowance for transformer replacement is provided through our substitute repex estimate. We recognise that Ergon Energy will be required to undertake some capital works triggered by Powerlink's planned transformer replacement. Ergon Energy's NPV analysis includes two expenditure items associated with this work:

- reconnection of tertiary supply ($700000)
- installing a temporary transformer during Powerlink's project timeframe to manage supply risk ($300000).

We have included $1 million in our substitute estimate to accommodate the planned Powerlink transformer replacement.

Broxburn, Yarranlea replacement and reinforcement

Ergon Energy proposed to replace existing transformers with new higher capacity transformers at both Broxburn and Yarranlea South zone substations in 2021. The driver of the Broxburn transformer replacement is demand in the Pittsworth region, which is forecast to exceed the substation’s capacity by 2022.[39] The Yarranlea South transformer replacement is purely driven on asset age (over 50 years).[40]

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37 Ergon Energy, *Blackwater 22kV options NPV analysis,* 23 May 2019.

38 Ergon Energy, *Planning proposal – Blackwater substation refurbishment,* 21 March 2019, p. 18.

39 Ergon Energy, *Planning proposal – Pittsworth, Broxburn & Yarranlea South refurbishment and reinforcement,* 21 March 2019, p. 1.

40 Ergon Energy, *Planning proposal – Pittsworth, Broxburn & Yarranlea South refurbishment and reinforcement,* 21 March 2019, p. 7.

Ergon Energy has demonstrated the need to increase capacity at Broxburn zone substation, but the transformer at Yarranlea is not yet due for replacement and capex for the transformer replacement would be included in our modelled repex forecast. We have included $3.2 million in our substitute estimate based on the cost to replace the transformer at Broxburn zone substation.

East Bundaberg to Burnett Heads 66kV Line Build

Ergon Energy proposed to build a 66kV feeder from East Bundaberg zone substation to Burnett Heads zone substation in 2021. The driver of this project is demand, which is expected to increase due to committed block loads including residential and tourist developments, and overload the existing three feeders.[41]

Ergon Energy has demonstrated that investment is required. It explained that due to the radial nature of the network supplying Burnett Heads, there is a need to maintain sufficient transfer capacity between the three feeders to ensure continued reliability in the area. It considered that in the event of a feeder fault, there is a risk of an extended outage as load cannot be readily restored by transferring load to adjustment feeders. Based on Ergon Energy's forecast, peak load on the Burnett Heads feeder will exceed capacity by 2022–23.[42] Ergon Energy also explained that voltage constraints and HV regulator capacity impose a limit of feeder loads and it does not have significant scope to boost regulator ratings.[43]

However, Ergon Energy has not demonstrated that a fourth feeder will be required during the 2020–25 regulatory control period. Ergon Energy may be able to defer the construction of the feeder to the subsequent regulatory period with some interim solutions:

- The current feeder ratings are constrained by the section of cables coming out of East Bundaberg zone substation. Ergon Energy could upgrade those cables and increase the feeder ratings.
- Ergon Energy has not considered the option of rebalancing load among the existing three feeders. This could alleviate the feeder overload on the Burnett Heads feeder and alleviate excessive voltage drops. This solution would require installation of feeder ties.
- Ergon Energy calculates a reduction in unserved energy of approximately $100000 from the proposed investment.[44] This benefit is insufficient to justify the new line investment of $5.4 million, but does indicate that alternative low-cost investments would likely be NPV positive if they can yield a similar benefit.
- Where voltage drop becomes severe as Ergon Energy has identified, a voltage regulator upgrade would be a lower cost solution than building a new 66kV line before it is needed.

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[41] Ergon Energy, *Planning proposal – Burnett Heads 66kV line augmentation,* 21 March 2019, pp. 5, 10.

[42] Ergon Energy, *Planning proposal – Burnett Heads 66kV line augmentation,* 21 March 2019, p. 19.

[43] Ergon Energy, *Planning proposal – Burnett Heads 66kV line augmentation,* 21 March 2019, pp. 19–20.

[44] Ergon Energy, *Planning proposal – Burnett Heads 66kV line augmentation,* 21 March 2019, p. 23.

Based on these findings, we have included $0.5 million in our substitute estimate to allow Ergon Energy to uprate feeder cables and build additional feeder ties where necessary. This would allow Ergon Energy to defer construction of the new 66kV feeder to the subsequent reset period.

Distribution growth

Ergon Energy proposed to address constraints in the 11kV medium-voltage, SWER and low-voltage networks. It categorises distribution level augmentation as follows:[45]

- Specified augmentation ($63.2 million) – consists of individual projects that are each required to resolve an identified constraint related to demand growth, voltage control or safety on the distribution networks.
- Reactive augmentation ($32.5 million) – required to address operational constraints and issues seen on the low-voltage networks that are not anticipated, forecast or planned by any other methodology. This category includes expenditure on defect rectification, bushfire mitigation and maintenance of the network to statutory requirements.

These are business-as-usual programs (BAU) of high-volume, low-value projects and past expenditure can provide a good indication of future expenditure need. Therefore, we have had regard to the expenditure trend. Ergon Energy's proposed $95.6 million is 10 per cent lower than the $106.7 million it expects to incur in the current period. We requested a further breakdown of the specified and reactive augmentation subcategories by their drivers (demand, voltage control, defect rectification, etc.), but Ergon Energy was unable to provide a breakdown at this level.[46]

Ergon Energy did provide evidence of the growth areas on its networks, and explained that even with low system peak demand growth, sustained population growth has still driven a need for distribution-level augmentation.[47] It has demonstrated that regional population growth will continue to drive a proportion of the program.

Although Ergon Energy could not provide a breakdown of the forecast expenditure at the level requested, we recognise that many components of specified and reactive augmentation will be recurrent in nature, such as voltage control and defect rectification. It is reasonable to assume that the future amount of augex may be similar to current period levels for a number of drivers. In this context, Ergon Energy's forecast distribution growth augex appears reasonable recognising that the forecast is approximately 10 per cent lower than current period levels and localised growth will remain a driver of expenditure. We have included Ergon Energy's proposed distribution growth augex in our substitute estimate.

45 Ergon Energy, *Strategic proposal distribution augex*, January 2019, p. i. Numbers revised to be consistent with $95.7 million proposal based on information provided in response to information request 3.

46 Ergon Energy, *Response to information request 3,* 20 February 2019, p. 5.

47 Ergon Energy, *Response to information request 8,* 21 March 2019, p. 2; Ergon Energy, *Response to information request 24*, 23 May 2019, pp. 29–41.

Power quality

Ergon Energy proposed capex to address power quality statutory obligations and enable increased penetration of solar PV and new technology connections. This includes:

- power quality monitoring ($4.6 million)
- solar PV augmentation ($9.1 million).

Power quality monitoring

Ergon Energy proposed to install an additional 1440 monitoring devices above the 2800 monitors that have been installed over the current and previous regulatory control periods.[48] It explained there are multiple benefits of the program, including time savings in identifying issues, and cost and time savings of installing temporary recording equipment.[49]

ECA's economic consultant Dynamic Analysis supported timely investment to integrate new technology into the grid, but queried whether cheaper solutions are available for Ergon Energy to achieve its objectives.[50]

Ergon Energy has not demonstrated the prudency and efficiency of the power monitoring program because:[51]

- Ergon Energy assumed in its cost-benefit analysis that each new monitoring device installed would deliver a $1600 annual saving by avoiding one quality of service investigation each year. Ergon Energy has not supported the assumption that one investigation per year could be avoided with each additional monitor and the assumption appears to us to overstate the effectiveness of the monitors.
- Ergon Energy indicated that it received approximately 2.1 power quality enquiries per month per 10000 customers.[52] The figure appears to be based on network wide numbers, and the majority of distribution feeders do not yet contain monitors.[53] The potential for each monitor to reduce power quality enquiries is not significant. We calculate that based on the existing population of monitors, the population of distribution transformers and Ergon Energy's customer base, the average annual benefit of an individual meter is $150, which is below the cost.
- Ergon Energy treated the avoidance of voltage regulator installations, voltage regulator setting adjustments and distribution transformer tap adjustments as a power quality monitoring benefit. It is not clear how power quality devices alone could achieve these outcomes. The decision to install voltage regulators must be

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48 Ergon Energy, *Strategic proposal for power quality*, January 2019, pp. 5, 20.

49 Ergon Energy, *Strategic proposal for power quality*, January 2019, pp. 17–19.

50 Dynamic Analysis, *Technical regulatory advice to the ECA – Review of 2020–25 regulatory proposals*, June 2019, p. 45.

51 Ergon Energy, *PQ NPV analysis,* 28 June 2019.

52 Ergon Energy, *Strategic proposal for power quality*, January 2019.

53 Ergon Energy's 2,800 monitors cover less than three per cent of its distribution transformer population. Ergon Energy, *Strategic proposal for power quality*, January 2019, pp. 5–10.

based on the need for voltage regulation and monitoring devices cannot reduce this need. Similarly, voltage regulator setting changes are needed where voltage is outside the operating envelope, and transformer tap change work is needed when supply voltage exceeds the relevant standard. Installing power quality devices cannot reduce these needs.

- Ergon Energy's NPV analysis has not included monitoring operational costs in its cost assessment. In addition, Ergon Energy compared the benefit against initial capital cost rather than the annualised capital cost.

Based on these concerns, we have not included Ergon Energy's power quality monitoring program in our substitute estimate.

Solar PV augmentation

Ergon Energy proposed BAU augex to install MV line regulators and low-voltage regulators to reactively manage existing and ongoing power quality issues caused by solar PV.[54] We recognise that Ergon Energy's customers will continue to install solar PV systems and Ergon Energy will need to manage the effects of those PV systems on its network. Ergon Energy has demonstrated that the proposed expenditure is prudent and efficient, as the forecast expenditure is broadly similar to 2015–20 regulatory control period. We have included the proposed capex in our substitute estimate.

Worst performing feeders

Ergon Energy proposed $4.1 million to continue its worst performing feeder (WPF) improvement program, which aims to improve the performance experienced by consistently poor performing feeders, in accordance with the Minimum Service Standards (MSS) set out in Ergon Energy's Distribution Authority.[55] Ergon Energy proposed 45 WPF improvement projects over the 2020–25 regulatory control period.[56]

Ergon Energy's WPF data indicates that there are at least 50 feeders in its network with a SAIDI outcome that is 200 per cent or greater the size of the respective MSS SAIDI limits. Ergon Energy is required to implement a program to improve the reliability of these feeders.[57]

Ergon Energy's proposed expenditure is 79 per cent lower than the $19.5 million it expects to incur during the current regulatory control period.[58] However, the reduction largely reflects expenditure of $15.8 million incurred in the 2015–16 financial year. Excluding 2015–16, the average annual expenditure is similar between 2016–17 and 2019–20 ($0.9 million) and the forecast period ($0.8 million).

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[54] Ergon Energy, *Strategic proposal for power quality*, January 2019, pp. 21–22.

[55] Queensland Government, *Distribution Authority No. D01/99 issued to Ergon Energy Corporation Limited*, September 2014, p. 16.

[56] Ergon Energy, *Strategic proposal for power quality*, January 2019, p. i.

[57] Queensland Government, *Distribution Authority No. D01/99 issued to Ergon Energy Corporation Limited,* September 2014, cl. 11.2(b).

[58] Ergon Energy, *Response to information request 3,* 20 February 2019, p. 3.

Ergon Energy's proposal to deliver 45 WPF improvement projects is of appropriate size to meet its regulatory obligations and the proposed cost is efficient. We have included the proposed capex in our substitute estimate.

Network communications

Ergon Energy proposed $69.7 million for network communications and network control projects to ensure compliance with regulatory obligations and provide additional network functionality. Its forecast is 20 per cent higher than the $58.2 million in expects to incur in the 2015–20 regulatory control period. We have reviewed the four higher value programs, including:

- intelligent grid enablement
- backup protection
- protection schemes
- telco technology capacity.

Intelligent grid enablement (IGE)

IGE is a combination of complementary operational software systems, customisations and integration mechanisms that will facilitate proactive management of the LV network. It consists of six components that allow for data collection and analytics, load control and DER management. IGE is complementary to the two other functional areas identified by Energex to proactively manage power flows on the network: the Advanced Distribution Management System (ADMS) and Low Voltage Network Monitoring and Visibility (LV monitoring).[59]

We received submissions from CCP14 and EnergyAustralia referencing Ergon Energy's proposed programs associated with managing the effects of DER.[60] CCP14 indicated that the amount of capex proposed for the IGE program appeared reasonable given the high level of DER being installed, but support the AER in reviewing the value of the program in recognition of other programs being proposed. EnergyAustralia considered that the AER and Ergon Energy should have a view beyond the value of DER arising from the customer-distributor relationship.

Ergon Energy has not justified the IGE for the following reasons:

- Ergon Energy has not demonstrated the need for this program under the NER or compliance with other regulations. It has not provided an NPV analysis to demonstrate that the benefits would exceed the proposed costs.
- Ergon Energy's business case for the IGE is underdeveloped and it has provided limited information regarding each of the capabilities it is intended to achieve. We are therefore not satisfied that the forecast is prudent and efficient.

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59 Ergon Energy, *Intelligent grid enablement strategic proposal*, January 2019, p. i.

60 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 regulatory proposals,* May 2019, p. 14; EnergyAustralia, *Submission on Ergon Energy's regulatory proposal 2020–25,* May 2019, p. 3.

- Ergon Energy stated that augmentation may be required to address future capacity and voltage constraints.[61] However, it has not set out the current performance levels or quantified the risks of constraints in the next regulatory control period. As such, the delivered benefits and the required scale of the program are unclear.
- We have concerns with some of the assumptions Ergon Energy has made in presenting the base case, such as addressing capacity and voltage constraints through traditional augmentation. We are therefore not satisfied that the proposed program is the most prudent option.
- Ergon Energy has not explained any interdependencies between the program and the ADMS and LV monitoring programs. It needs to show what effect the scope and deliverability of each program has on the benefits and risks of the IGE program.

Backup protection

Ergon Energy proposed to rectify backup protection across approximately 53,000 km of its network that it has determined are non-compliant with NER S5.1.9 and present a safety risk.[62] Ergon Energy explained that in accordance with NER S5.1.9(c), it is required to have two independent forms of protection that can detect and clear all credible fault.[63]

Clause S5.1.9 requires that primary and backup protection are available 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 considering the relevant fault clearance time and reach of both the existing primary protection systems and the existing backup protection systems.

Ergon Energy has not justified the program for the following reasons:

- Ergon Energy determined the scope of investment based on desktop analysis only. It did not conduct any field test or analyse past protection failures to verify and validate its desktop analysis. A field test is required to validate the desktop assessment and demonstrate the prudency of the proposed expenditure.
- Ergon Energy did not provide evidence that any shortfall in its protection systems that do not meet 1.5 reach has led to protection failure. It has therefore not demonstrated that not meeting 1.5 reach presents a material risk, such that damage to the power system could reasonably occur. The need could be demonstrated through engineering analysis for a representative sample of feeders showing that the existing protection system on those feeders would not prevent equipment damage in the event of a fault.
- Ergon Energy provided historical information of serious incidents relating to members of public coming into contact with live conductors.[64] However, it is not

[61] Ergon Energy, *Intelligent grid enablement strategic proposal*, January 2019, pp. 1–2.

[62] Ergon Energy, *Strategic scope – backup reach program*, January 2019, p. 1.

[63] Ergon Energy, *Response to information request 53,* 28 June 2019, p. 4.

[64] Ergon Energy, *Response to information request 24,* 23 May 2019, pp. 24–26.

clear whether the inadequacy of the backup protection system in place contributed to any of the respective incidents.

Ergon Energy expects that setting changes and installing line fuses will be the solution for approximately 70 per cent the protection units in the 2020–25 regulatory control period. We are satisfied that Ergon Energy has explored a range of solutions to backup protection issues and the proposed solutions would be efficient.

However, setting changes are a normal operational activity, because protection settings are reviewed and adjusted as the network is reconfigured, as loads alter or as works are undertaken that change the network characteristics. Expenditure for setting changes is already incorporated within the opex allowance. We have not included Ergon Energy's proposed capex for backup protection in our substitute estimate.

Protection schemes

Ergon Energy proposed to install new protection equipment to detect and clear faults from the power system to ensure the network is safe and legislative obligations are met.[65] It explained that its existing protection systems were designed to manage faults where energy was supplied from centralised sources. With increasing solar PV, reverse power flows are becoming an issue and the ability to detect and clear faults is not guaranteed.[66] Ergon Energy explained that this category of expenditure currently has no historical spend as the works in the space have been directly associated with large DER connections in contrast to managing micro embedded generation.[67]

The proposed protection schemes program has three components:

- protection for networks with high DER penetration
- transformer protection duplication
- sensitive earth fault protection.

We have had regard to the project for the protection of networks with high DERs, under which Ergon Energy would install diverse communications services and control schemes to reliably shut down systems in the event of a network fault.[68]

Ergon Energy explained that there are 640 high-voltage feeder networks with significant PV penetration and frequent occurrences of reverse power flows.[69] It considers these reverse power flows and a protection failure can produce an islanded network and where some fault scenarios cannot be cleared. It considers this to be a credible fault scenario, which means adequate protection systems must be in place in accordance with the NER. It adds that this is an emerging problem and there have been no records of non-compliance.[70]

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65 Ergon Energy, *Strategic proposal – protection schemes*, January 2019, p. 1.

66 Ergon Energy, *Strategic proposal – protection schemes*, January 2019, p. 3.

67 Ergon Energy, *Strategic proposal – protection schemes*, January 2019, p. 4.

68 Ergon Energy, *Strategic proposal – protection schemes*, January 2019, pp. 3–4.

69 Ergon Energy, *Response to information request 41,* June 2019, p. 4.

70 Ergon Energy, *Response to information request 41,* June 2019, p. 4.

We recognise that networks require suitable protection arrangements to comply with the regulatory obligations that Ergon Energy has cited.[71] However, Ergon Energy has not demonstrated the need for protection in areas of high DER penetration, or the efficiency of the proposed solution, for the following reasons:

- Ergon Energy has not demonstrated to us that there is a compliance issue. It was unable to provide examples of protection failures or incidents of non-compliance, and has not provided evidence from its surveys that demonstrate how it determined the scale of non-compliance. Because of this, it is unclear if the proposed augex is of appropriate size to address the need.
- It is not clear what assets Ergon Energy proposes to install, the cost of these assets and how the installation and operation of these assets will address the expected need. Further, Ergon Energy has not provided options analysis, therefore it is unclear that Ergon Energy's proposed solution is most appropriate to address the need.
- Ergon Energy did not fully quantify risks when preparing its forecast for the program. Instead, it has relied on risk matrices that assign a qualitative value to risk likelihood and consequence to arrive at a semi-quantitative risk score.[72] The risk score appears to be useful in prioritising areas where protection may need to be improved, but it does not sufficiently demonstrate the prudency and efficiency of the program.

We have not included Ergon Energy's proposed program for networks with high penetration of DERs in our substitute estimate, but we have included the proposed capex for the other two programs. We are satisfied that these two programs are likely to be prudent due to high-value of power transformer assets and public safety risks associated with the lack of sensitive earth fault protection.

Network capacity and coverage

Ergon Energy proposed to increase the capacity and resiliency of its communications network through increasing communications coverage across the state. The program contains four subcomponents:

- telecommunications passive augmentation
- telecommunications transmission augmentation
- telecommunications technology introduction
- external removal of third party infrastructure.

We have had particular regard to the telecommunications transmission augmentation project, which is aimed at relieving capacity constraints in existing telecommunications infrastructure such as optic fibres and networking equipment. Ergon Energy explained that demand on its telecommunications assets is increasing due to growth in active

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71 Ergon Energy, *Strategic proposal – protection schemes*, January 2019, p. 2.

72 Ergon Energy, *Strategic proposal – protection schemes*, January 2019, pp. 5–6.

monitoring and increasing data carriage requirements.[73] Under its preferred option, additional capacity would be installed under a 'just-in-time' approach as forecast needs are confirmed.[74]

Ergon Energy provided evidence of remaining communications capacity, and it explained that there are 140 fibre optic cables and five microwave links and IP equipment on its network projected to exceed thresholds in the 2020–25 regulatory control period.[75] With regard to fibre capacity, Ergon Energy's evidence showed for each individual cable the number of fibres that are being utilised and the number of spares.[76] One individual fibre has sufficient bandwidth to carry multiple communications through Wavelength Division Multiplexing (WDM), and it is not clear how efficiently Ergon Energy is using the capacity of individual fibres. There may be scope to free up existing fibres in strategic locations to ensure that growing data requirements could be met through existing assets.

We had regard to the risk assessment, which is based on the as low as reasonably practicable (ALARP) principle. Ergon Energy's assessment is qualitative. Good industry practice risk assessment under the ALARP principle is to apply a quantitative assessment. Ergon Energy also did not present any supporting evidence of its risk assessment. For example, it expects that protection failures may occur as a result of communications failure.[77]

We have not included Ergon Energy's proposed the telecommunications transmission augmentation project in our substitute estimate, but we have included the proposed capex for other three subcomponents that form the network capacity and coverage program.

A.3 Connections capex

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 new customer demand.

A.3.1 Draft decision

We are satisfied based on our analysis that Ergon Energy's initial net connections capex forecast of $206.2 million and contributions forecast of $169.9 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have therefore included these amounts in our substitute estimate of total capex.

73 Ergon Energy, *Strategic scope – Network capacity and coverage*, January 2019, p. 3.

74 Ergon Energy, *Strategic scope – Network capacity and coverage*, January 2019, p. 7.

75 Ergon Energy, *Response to information request 41,* 7 June 2019, p. 6.

76 Ergon Energy, *Transmission augmentation – capacity analysis v.1.1,* 7 June 2019.

77 Ergon Energy, *Strategic scope – Network capacity and coverage,* January 2019, p. 9.

A.3.2 Ergon Energy's proposal

Ergon Energy proposed $206.2 million in net connections capex. This represents an 8 per cent decrease on current regulatory period net connections. Ergon Energy also proposed $169.9 million in capital contributions which is 19 per cent lower than the $210.7 million of capital contributions estimated to be received in the current period.

Ergon Energy has based its connections and contributions forecasts on a simple top-down methodology. It derived 2018–19 connections expenditure using actual connections capex from the first few months of 2018–19 and estimated expenditure for the balance of the year. This estimated expenditure level was then trended over the 2020–25 period.[78] It justified using the single year, rather than a range of years, due to significant uncertainty in forecasting connections capex in a post-mining boom environment. ECA's economic consultant Dynamic Analysis considered that Ergon Energy's approach to rely on actual connections capex was reasonable but had shortcomings as economic activity is likely to affect connections volumes.[79]

A.3.3 Reasons for draft decision

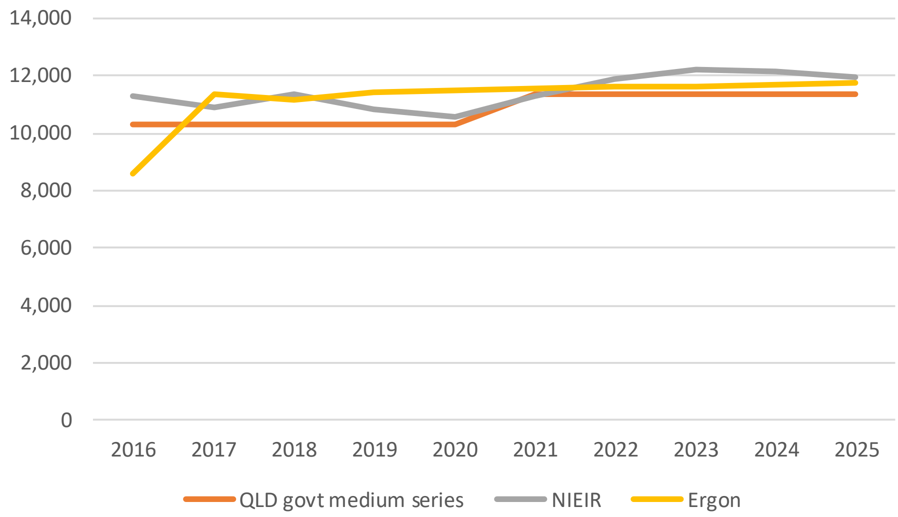
Ergon Energy did not provide evidence supporting its customer connection volumes forecast, but we had regard to independent housing forecasts that appear to support Ergon Energy's figures. One forecast is constructed by the National Institute of Economic and Industry Research (NIEIR) for the Queensland Government, and the other the Queensland Government's own forecast.[80] We have had particular regard to NIEIR's forecast, which was produced in 2018 and is therefore reasonably current. The three forecasts are shown in Figure A.1.

78 Ergon Energy, *Response to information request 8,* 3 April 2019, pp. 1–3.

79 Dynamic Analysis, *Technical regulatory advice to the ECA – Review of 2020–25 regulatory proposals,* 5 June 2019, p. 46.

80 NIEIR, *Queensland region construction supply and demand analysis: 1995–2028 and quarterly indicators to June 2020,* November 2018, table A.19, p. 137; Queensland Government, *'Projected dwellings, by series, by statistical area level 4, Queensland, 2011 to 2036',* May 2019.

Figure A.1 – Ergon Energy, NIEIR and Queensland Government annual residential connection volumes/dwelling completions, historical and forecast



Source: Ergon Energy's reset RIN, NIEIR and Queensland Government forecasts, and AER analysis.

Figure A.1 shows that the historical series are not entirely consistent, suggesting some differences in the methodology used to determine actuals. However, all forecasts suggest a similar trend for future dwelling construction:

- Ergon Energy has forecast approximately 11600 residential connections per year or about 58300 residential connections over the 2020–25 regulatory control period.[81] This is an 8 per cent increase in annual connection volumes.
- The Queensland Government's medium-growth forecast is for approximately 11,400 new residential dwellings per year from 2021 in Ergon Energy's region.
- NIEIR forecast approximately 11,900 new residential dwellings per year over the 2020–25 regulatory control period. NIEIR also forecast similar growth in residential dwellings, 8 per cent above 2015–20 regulatory control period levels, relative to Ergon Energy's forecast growth of 88 per cent.

We also had regard to Ergon Energy's forecast unit rates. We found that the forecast unit rate for residential connections is 13 per cent lower than current period levels. The overall unit rate (including commercial connections) is 17 per cent lower than current period levels.

On the evidence above, we are satisfied that both the connections and capital contributions forecasts are reasonable and we have therefore included these amounts in our substitute estimate of total capex.

[81] AER analysis of Ergon Energy's 2020–25 reset RIN.

A.4 Repex

Replacement capital expenditure (repex) must be set at a level that allows a distributor to meet the capex criteria. 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 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[82]
- 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 on the network.

The majority of network assets will remain in efficient use for far longer than a single five-year 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 Ergon Energy's assets that will likely require replacement over the 2020–25 regulatory control period and the associated capex.

A.4.1 Draft decision

We do not accept that Ergon Energy's proposed repex of $1094.4 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included an amount of $842.0 million in our substitute estimate of total repex. This is a reduction of $252.4 million (23 per cent). We are satisfied that our substitute estimate would form part of a total capex forecast that reasonably reflects the capex criteria. Table A.2 summarises Ergon Energy's repex forecast and our draft decision.

Table A.2 – Draft decision on Ergon Energy's total forecast repex ($ million, 2019–20)

	Ergon Energy's proposal	AER draft decision	Difference ($)	Difference (%)
Modelled repex	765.0	637.1	-127.9	-17%
Unmodelled repex	329.4	204.9	-124.5	-38%
Total	**1094.4**	**842.0**	**-252.4**	**-23%**

Source: Ergon Energy's reset RIN and AER analysis.

Note: Numbers may not sum due to rounding.

[82] 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.

A.4.2 Ergon Energy's proposal

Ergon Energy proposed a repex forecast of $1094.4 million for the 2020–25 regulatory control period. The forecast is $221.9 million, or 25 per cent, higher than its actual and estimated repex of $872.5 million over the 2015–20 regulatory control period. In summary, Ergon Energy submitted that the key drivers for this expenditure are:

- it is taking a more proactive approach to replacing aging assets
- increasing asset age, resulting in increased network and safety risks
- ensuring community and staff safety and legislative obligations.[83]

A.4.3 Reasons for draft decision

We have applied several techniques to assess Ergon Energy's proposed repex forecast against the capex criteria, as well as considering stakeholder submissions. These techniques include:

- trend analysis
- repex modelling
- top-down and bottom-up assessments
- technical and engineering review.

Total repex

At the total repex level, we relied on trend analysis, top-down and bottom-up assessments, and technical and engineering review to form our position on Ergon Energy's forecast. We also considered stakeholder submissions that related to Ergon Energy's total repex forecast.

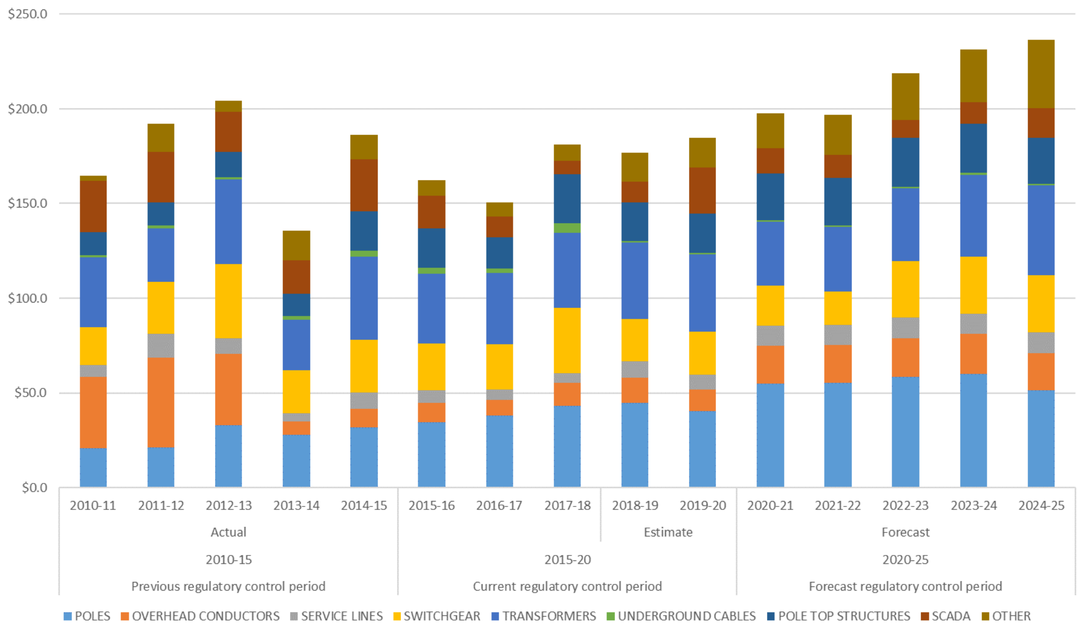
Trend analysis

Figure A.2 highlights that Ergon Energy is forecasting a significant increase in repex over the 2020–25 regulatory control period. In addition, CCP14 commented "the prudency and efficiency of this increase (in repex) is of concern to customers."[84] Ergon Energy is also forecasting an increase in asset replacement volumes over the same period, as highlighted below in the 'modelled repex' and 'unmodelled repex' sections.

[83] Ergon Energy, *Regulatory proposal 2020–25,* January 2019, pp. 63–66.

[84] CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 regulatory proposals,* May 2019, p. 8.

Figure A.2 – Ergon Energy's historical vs forecast repex (by asset group) ($ million, 2019–20)



Source: Ergon Energy's recast CA RIN and reset RIN, and AER analysis.

Ergon Energy has indicated that its first three years of repex in the current period are not representative of its repex requirements over the forecast period, primarily due to an increasing age profile.[85] However, Ergon Energy did not sufficiently justify the increases in repex to these higher levels for the 2020–25 regulatory control period in its proposal and subsequent information request responses.

Top-down and bottom-up assessments

Ergon Energy's proposal stated:

> While we recognise there are limitations to the age-based approach inherent in repex modelling, it is one tool we use for a top-down challenge of our repex forecast using a bottom-up build. This was done both at an overall repex level and at an asset category group level where applicable…[86]

Ergon Energy identified some efficiencies in justifying its proposal, such as replacing assets opportunistically alongside other replacement programs. However, it is unclear how the top-down review affected its repex forecast. In addition, EMCa's review identified that "the process includes application of management (financial) constraints".[87]

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[85] Ergon Energy, *Regulatory proposal 2020–25*, January 2019, p. 63.

[86] Ergon Energy, *Regulatory proposal 2020–25*, January 2019, p. 67.

[87] EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, p. 18.

Consistent with previous decisions, a lack of a top-down review generally indicates that the distributor has not adequately accounted for the interrelationships, overlapping over effects[88] and synergies between programs, projects and work areas, which is likely to inflate forecast expenditure. EMCa also observed this about Ergon Energy's overarching governance and management framework and its capital expenditure forecasting methods.[89]

Ergon Energy's bottom-up methodology for asset groups is broadly outlined in the high-level justification statements provided in its proposal documents.[90] However, the justification statements do not explain why a particular volume of asset replacements is required, or how network risks would change quantitatively if a higher or lower replacement level was selected. Rather, the justification statements qualitatively discuss how a higher replacement volume would decrease risks, and vice versa. Overall, the documents do not clearly demonstrate that its forecast replacement volumes are prudent and efficient.

Importantly, Ergon Energy did not fully quantify risks when preparing its repex forecast. Instead, it has relied on risk matrices that assign a qualitative value to risk likelihood and consequence to arrive at a semi-quantitative risk score. The risk scores appear to be useful in prioritising repex programs and projects, but they do not sufficiently demonstrate the prudency and efficiency of these investments. Therefore, it cannot be concluded that Ergon Energy’s forecast reasonably reflects the capex criteria. We highlighted similar concerns in our augex assessment in section A.2.

We typically expect distributors to provide quantified analysis such as cost-benefit analysis or options analysis as supporting justification. We provided this feedback to Ergon Energy throughout our ongoing engagement and discussed the type of quantitative analysis we would typically expect to receive in support of a distributor's repex forecast.[91]

In response, Ergon Energy stated "…our mature risk management methodology… does not involve monetising risk or placing a cost on consequences."[92] In addition, Ergon Energy directed us back to its justification statements and provided sample NPV analysis for a few programs. We discuss these NPV analysis spreadsheets below in 'modelled repex'.

Technical and engineering review

As noted above, we engaged EMCa to conduct a review of Ergon Energy's total repex forecast. In regards to the total repex level forecast, EMCa stated:

88 For example, replacing a zone substation asset and a feeder would both improve supply reliability, but these effects are typically analysed in isolation.

89 EMCa, *Review of aspects of Ergon Energy and Energex’s forecast capital expenditure,* August 2019, p. 68.

90 Ergon Energy, *Justification statements for 11 asset groups,* January 2019.

91 AER, *Information request 13*, March 2019.

92 Ergon Energy, *Response to information request 27*, May 2019, pp. 9–14.

> We consider that the systemic issues identified in our assessment are reflected in a number of biases that have led to a material over-estimation of forecast replacement capital expenditure.[93]

EMCa also stated that "based on the projects and programs we reviewed, we find that Ergon Energy's repex forecast does not meet the NER expenditure criteria because it has not demonstrated that it is efficient, prudent and reasonable."[94] Specifically, EMCa found the following systemic issues:

- lack of supporting justification for programs and projects included in the proposed expenditure
- a top-down constraint on expenditure to meet management constraints (such as a price outcome)
- a potential bias to overestimate costs and forecasts that were overly risk conservative
- limited economic options analysis. [95]

Throughout Ergon Energy's repex proposal, there are often inconsistencies between its risk-orientated forecast and project build. For example, Figure A.3 shows that while Ergon Energy claims its increased repex forecast reflects an increase in risk due to aging assets, a majority of its programs and projects, and therefore forecast repex, are categorised as low or moderate risk. EMCa also noted these inconsistencies in its review of Ergon Energy's total repex forecast, stating:

> We observe that there are only a small number of projects identified to address intolerable, very high and high risks; whilst the majority of the expenditure is targeting moderate/medium and low risks.[96]

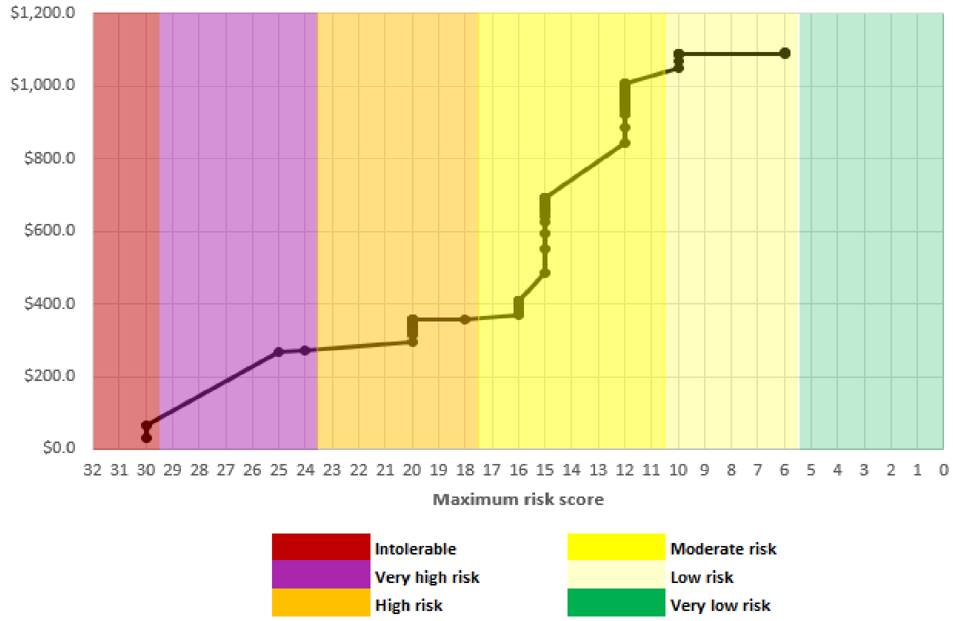
93 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, p. 68

94 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, p. 68.

95 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, pp. 63–68.

96 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure*, August 2019, p. 28.

Figure A.3 – Ergon Energy's repex build by risk score ($ million, 2019–20)



Source: Ergon Energy 7.026 and AER analysis.

Substitute estimate

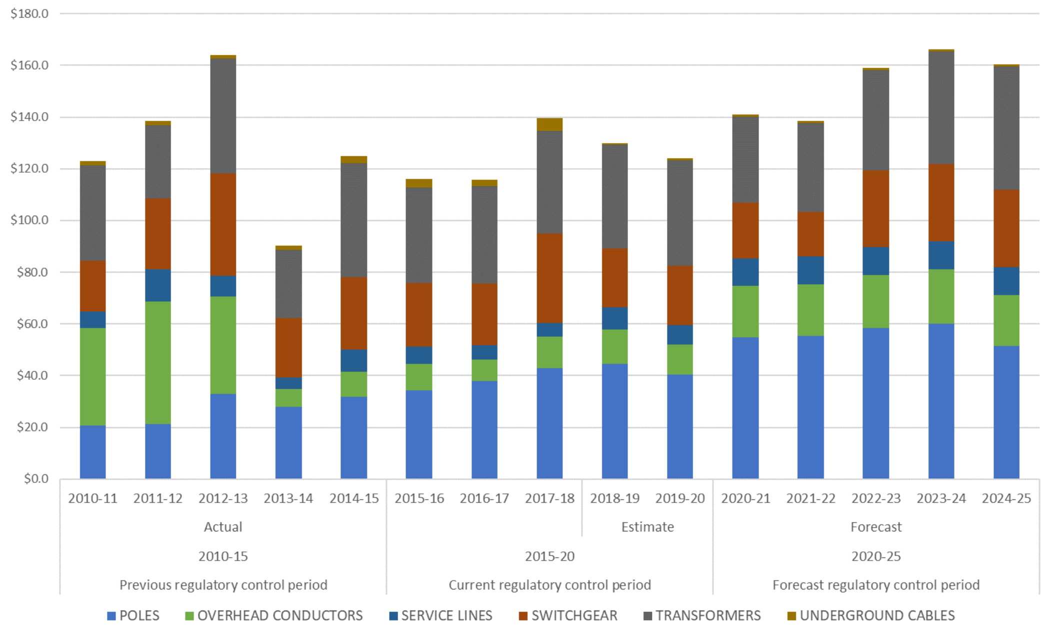
Overall, Ergon Energy has not established that its total repex forecast of $1094.4 million is prudent and efficient, and its forecast would not form part of a total capex forecast that reasonably reflects the capex criteria. As the increased risk and repex forecast has not been adequately justified, we have included an amount of $842.0 million in our substitute estimate. This amount is more in line with Ergon Energy's actual and estimated repex of $872.5 million over the 2015–20 regulatory control period. Below we discuss the basis for our substitute estimate, including why we are satisfied it would form part of a total capex forecast that reasonably reflects the capex criteria.

Modelled repex

Ergon Energy's proposal included $765.0 million in modelled repex for the 2020–25 regulatory control period. This accounts for 70 per cent of Ergon Energy's repex forecast. We do not consider that this forecast would form part of a total capex forecast that reasonably reflects the capex criteria. Our substitute estimate for this repex component is $637.1 million. We relied on trend analysis, repex modelling, and technical and engineering review to form our position on Ergon Energy's modelled repex.

Trend analysis

Figure A.4 – Ergon Energy's historical vs forecast modelled repex (by asset group) ($ million, 2019–20)



Source: Ergon Energy's recast CA RIN and reset RIN, and AER analysis.

Figure A.4 highlights a similar trend to the total historical and forecast repex trend outlined in Figure A.2. Ergon Energy is forecasting its modelled repex in the 2020–25 forecast period to significantly exceed its actual and estimated modelled repex in the current regulatory control period. Notably, Ergon Energy is forecasting a significant increase in repex for poles, overhead conductors and service lines, and a moderate increase in transformers. These asset group trends have also been compared with our repex model results to form focus areas for our bottom-up assessment.

Repex modelling

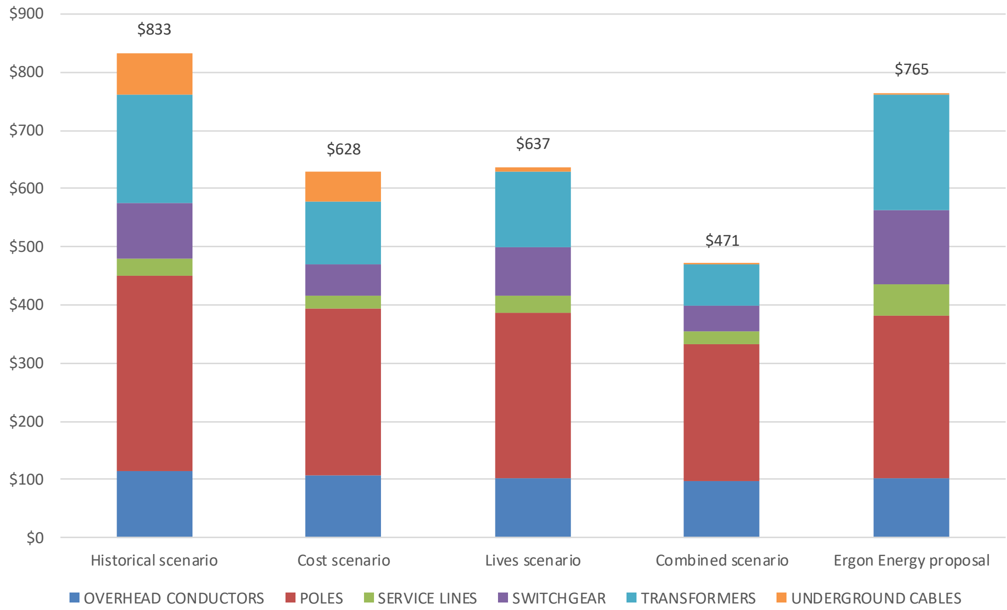
We use our repex model to forecast replacement volumes and expenditure for the pole, overhead conductor, service line, switchgear, transformer and underground cable asset groups. We do not use the repex model for the pole top structure, SCADA and other asset groups. Appendix A.4 outlines more information regarding our repex modelling approach.

We applied the repex model to Ergon Energy's modellable asset categories 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 A.5 highlights Ergon Energy's modelled repex forecast compared with our four modelled scenarios.[97] The 'repex model threshold' is the lives scenario. Ergon Energy's proposal is $127.9 million (17 per cent) greater than the repex model threshold. This indicates that on average, Ergon Energy's repex forecast has higher unit costs and lower expected replacement lives than other distributors. Ergon Energy's proposal for modelled repex is significantly higher than our results for service lines, switchgear and transformers. We used these results alongside the trend analysis discussed above to identify asset groups and categories to examine in greater detail and to help inform our bottom-up assessment.

Figure A.5 – Four modelled scenarios vs Ergon Energy's modelled repex forecast ($ million, 2018–19)



Source: AER analysis.

We presented our modelling approach, including preliminary modelling results to Ergon Energy during our capex deep dive session on 8 November 2018 and discussed the model further during our ongoing engagement with Ergon Energy. During this engagement, Ergon Energy raised an issue relating to staked wooden pole data reporting requirements.[98] In response, Ergon Energy provided us with feedback on the repex model and outlined preliminary results of its own repex modelling analysis.[99] We appreciate Ergon Energy for engaging with us on our repex model approach. Below we discuss Ergon Energy's own repex modelling results and an issue raised regarding wooden pole modelling techniques.

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97 AER, *Draft decision – Ergon Energy distribution determination 2020–25 – Repex model,* October 2019.

98 Ergon Energy, *Teleconference between Ergon Energy and AER staff to discuss repex modelling,* 23 May 2019.

99 Ergon Energy, *Response to June 4 meeting – Capex Energy Queensland repex modelling,* 28 June 2019.

Ergon Energy's internal repex modelling

In its response, Ergon Energy outlined that there was approximately a $79 million gap between its calculated repex model threshold and its modelled repex proposal, and explained the factors that contributed to this difference.[100] In some instances, Ergon Energy indicated that it had forecast higher replacement volumes, such as for services lines, or a higher unit rate than the benchmark unit costs, such as for distribution transformers. Although this helped to explain why there might be a difference between Ergon Energy's own modelling results and its total modelled repex forecast, it did not help to justify why the total modelled amount is prudent and efficient.

Ergon Energy also outlined that its Childers to Gayndah 66kV feeder replacement project was unlikely to have sufficient previous replacement history for asset types in this feeder (e.g. concrete poles and 66kV overhead conductor).[101] While this may be true, any potential bias may be offset by other modelled asset categories that are captured in the calibration period, but are not necessarily required in the forecast regulatory control period.

Consistent with the repex model's top-down application, that a large replacement project that falls outside business-as-usual practice, such as the Childers to Gayndah 66kV feeder replacement project, could be justified as prudent and efficient through risk-based cost-benefit analysis that considers all viable options, including a base-case or counterfactual option. As highlighted in section A.4, Ergon Energy did not provide this analysis in its proposal or subsequent information request responses.

Wooden pole modelling techniques

Ergon Energy's response noted that there were differences in the expected asset replacement lives of wooden poles between its own repex model results and our preliminary results provided in May 2019.[102] However, as Ergon Energy noted, these preliminary results were based on older historical data and not the recast historical CA RIN data that Ergon Energy provided. Our revised repex model results that used Ergon Energy's recast data, outlined in Figure A.5, more closely aligned with Ergon Energy's own calculations. This partially addressed the differences in wooden pole expected asset replacement ages that Ergon Energy raised.

However, Ergon Energy also advised us that it reported its wooden pole asset age profile data differently to the way we typically interpret this data.[103] For example, our current approach assumes that staked wooden poles are reported as unique assets in the 'staking of a wooden pole' asset category in worksheet 5.2 of the CA RIN. However, Ergon Energy advised that it does not report these assets as unique and confirmed that this was noted in its basis of preparation. Instead, Ergon Energy reports the year in which the wooden pole was staked in the 'staking of a wooden pole' asset category, but it also reports the year in which the original wooden pole was installed.

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100 Ergon Energy, *Response to June 4 meeting – Capex Energy Queensland repex modelling,* 28 June 2019, pp. 3–4.

101 Ergon Energy, *Response to June 4 meeting – Capex Energy Queensland repex modelling,* 28 June 2019, p. 4.

102 Ergon Energy, *Response to June 4 meeting – Capex Energy Queensland repex modelling,* 28 June 2019, p. 5.

103 Ergon Energy, *Meeting between AER and Ergon Energy to discuss pole blending,* 12 June 2019.

As a result, we checked the basis of preparation information of all distributors with wooden poles in their networks in an effort to find a consistent approach. Our analysis indicates that Ergon Energy is the only distributor that explicitly states that staked wooden poles are not reported as unique assets, while Essential is the only distributor that explicitly states that staked wooden poles are reported as unique assets. The remaining distributors do not explicitly state how they report staked wooden poles one way or the other.

Following these discussions, we analysed the underlying age profile and replacement volume data that is used for calibration, to determine the best way to model Ergon Energy's wooden pole asset categories (including staked wooden poles). Overall, our analysis revealed that Ergon Energy's repex model threshold would likely be immaterially lower than the repex model results outlined in Figure A.5. As a result of this analysis and the data reporting uncertainty outlined above, we have not adjusted the repex model results.

Nevertheless, this issue can be discussed in response to our repex model issues paper, which was published in late August 2019. Submissions are due in early October 2019 and we therefore encourage Ergon Energy and any other interested stakeholders to provide a submission in this process.

Bottom-up engineering assessment

Our trend analysis and repex modelling results enabled us to focus on specific programs and projects in Ergon Energy’s modelled repex forecast and filter out others that did not raise as many concerns. For example, trend analysis indicated that underground cables repex is expected to decline over the 2020–25 regulatory control period and our repex modelling results provided a threshold amount ($8.9 million) that was above Ergon Energy’s proposal ($4.2 million). We therefore did not focus our bottom-up assessment on these assets as much as other asset groups.

As mentioned previously, Ergon Energy's proposal did not contain substantial analysis to support its repex forecasts. It is unclear how or why a particular volume of asset replacements was selected and whether the chosen replacement volumes are required. We therefore asked Ergon Energy for this analysis in an information request to assess whether the proposed repex was prudent and efficient.[104]

In response, Ergon Energy provided a small sample of least-cost options spreadsheets, which again contained minimal information. Further, most responses referred back to Ergon Energy’s proposal, which did not contain quantified risk-based analysis. EMCa also noted this lack of supporting information, stating:

> Ergon Energy includes a summary of its risk assessment approach in the supporting information provided for many of the projects included in the repex

[104] AER, *Information request 13*, March 2019.

> forecast. However, we did not see similar evidence for many of the programs we reviewed.[105]

Consistent with our standard approach, we typically expect distributors to provide evidence of how it forecast repex and replacement volumes at a more granular program and project level. We expect distributors to quantify the risks associated with its network and to demonstrate that a particular investment decision is likely to be prudent because the costs of the investment are likely to be less than the expected benefits.

Ergon Energy outlined that it does not test the prudency of its proposed investments using an economic framework. Rather, it uses its semi-quantitative risk framework to decide that an investment is needed and then seeks to implement the lowest cost option available. Further, Ergon Energy does not consider quantitatively what is likely to happen under the base case or counterfactual scenario where assets are replaced reactively. As mentioned previously, Ergon Energy stated several times throughout the engagement process that it does not quantify risk, particularly safety risks.[106]

In addition, Ergon Energy generally does not quantify unserved energy risk, which is a standard industry approach that accounts for expected unserved energy and the value customers place on reliability. Overall, our bottom-up review of a sample programs and projects revealed systemic issues with Ergon Energy's repex forecast.

Transformers replacement volumes

Ergon Energy derived its replacement volume forecast for power transformers though a detailed condition-based risk model (CBRM) that ranks asset health. Ergon Energy noted that its CBRM model suggested that 60 transformers could be replaced over the 2020–25 period based on asset condition, load, rating and other critical factors.

However, during the on-site visit Ergon Energy outlined that it was forecasting to replace 31 power transformers out of the model output of 60, claiming that this was prudent because it was below the repex model results. When asked why exactly 31 power transformers were chosen for replacements rather than an alternative number, Ergon Energy was unable to answer. EMCa highlighted similar concerns about Ergon Energy's bottom-up forecasting methodology for both this transformer example and other asset groups where Ergon Energy's CBRM model was applied.[107]

Childers to Gayndah

Ergon Energy's proposal included a project to replace the entire Childers to Gayndah feeder, which is 99 kilometres in length.[108] Ergon Energy states that the replacement is necessary due to asset aging and deterioration. While Ergon Energy supported its

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105 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, p. 25.

106 Ergon Energy, *Response to information request 27*, May 2019, pp. 9–14.

107 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, 32–33.

108 Ergon Energy, *Planning proposal – Childers to Gayndah*, January 2019, p. 21.

claim of asset deterioration with evidence, it did not provide sufficient evidence to support the proposed replacement.

Ergon Energy submitted two other network replacement options for consideration, but the base case or counterfactual option of continuing to operate this feeder was rejected because "it does not address the existing network risks which are not deemed to be as low as reasonably practicable".[109] Rather than conducting cost-benefit analysis, Ergon Energy conducted a simple least-cost NPV analysis, concluding that their recommended option was the cheapest or least negative in net present terms at negative $24.4 million.

In response to information requests, Ergon Energy provided its modelling for the project. The model indicated that the economic efficient solution is to do nothing, yet this option was rejected without proper assessment. Overall, Ergon Energy did not provide evidence that its replacement program is prudent, efficient or necessary.

Additionally, Ergon Energy’s risk assessment practices do not align with current good industry practice and it has materially overstated the safety risk. For example, Ergon Energy's Childers to Gayndah planning proposal assumes a fatality likelihood rating of 3 and a serious injury likelihood rating of 5.[110] Ergon Energy therefore overstated its safety consequence significantly, as these scores correspond to one fatality and 50 injuries per year,[111] where in reality, Ergon Energy’s entire network has not experienced this level of consequence.

Substitute estimate

Ergon Energy provided several least-cost analysis spreadsheets to help support some of its repex program and project forecasts. However, given the lack of detailed analysis and risk quantification, it did not adequately demonstrate that its repex forecast is likely to reflect the capex criteria. EMCa's findings of overestimation bias due to the inclusion of low-risk projects without adequate justification confirms our concerns that Ergon Energy's forecast repex is overstated.[112] We encourage Ergon Energy to provide additional supporting justification for its modelled repex forecast, including risk-based cost-benefit analysis, in its revised proposal.

As Ergon Energy did not sufficiently support its proposal through cost-benefit analysis or other rigorous risk assessments, we were unable to derive a substitute estimate from our bottom-up analysis. In the absence of robust risk-based cost-benefit analysis, we have relied on our repex modelling results to determine our substitute estimate of $637.1 million for modelled repex.

The repex model output is supported by trend analysis, which indicates that Ergon Energy's proposal of $765.0 million for modelled repex is materially higher than Ergon Energy’s historical repex. The capex factors require us to consider past and expected

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109 Ergon Energy, *Planning proposal – Childers to Gayndah,* January 2019, p. 38.

110 Ergon Energy, *Planning proposal – Childers to Gayndah,* January 2019, p. 20.

111 Ergon Energy, *Asset management overview, Risk and optimisation strategy,* January 2019, p. 14.

112 EMCa, *Review of aspects of Ergon Energy and Energex’s forecast capital expenditure*, August 2019, p. 25.

expenditure.[113] Both Ergon Energy's prorated expenditure using its historical expenditure over the first three years of the current regulatory control period ($618.6 million), and its actual and expected expenditure for the current regulatory control period ($625.2 million) are closer to and more in line with our substitute estimate than Ergon Energy's proposal.

In addition, our estimate is greater than Ergon Energy's prorated and expected expenditure for this regulatory control period. This is primarily because our estimate derived using the repex model takes a distributor's asset age profile into account, rather than simply relying on past expenditure.

Unmodelled repex

In general, unmodelled repex asset groups and categories cannot be modelled using the repex model because the assets are more heterogeneous, do not have relevant age profile data, cannot be compared with other businesses, or expenditure tends to be more volatile in nature.

Ergon Energy's proposal included $329.4 million in unmodelled repex, of which $13.1 million is forecast for public lighting assets. We do not consider that standard control service (SCS) customers should fund the cost of replacing alternative control service (ACS) public lighting assets. Ergon Energy explained that operationally SCS and ACS capex works are often bundled together. However, we believe this expenditure should be correctly allocated to SCS and ACS capex, respectively.

Therefore, our substitute estimate excludes this forecast repex for public lighting assets. EMCa supports this position.[114] We encourage Ergon Energy to provide additional evidence explaining why this expenditure should be allocated to SCS capex or, if required, add it back into its ACS capex forecast in its revised proposal. Any historical and forecast public lighting capex amounts have been excluded from the analysis below, including in Figure A.6, for direct comparison purposes. The remainder of this unmodelled repex analysis relates to the remaining $316.3 million in Ergon Energy's proposal.

Trend analysis

Figure A.6 outlines Ergon Energy's historical unmodelled repex and its forecast unmodelled repex by asset group. Ergon Energy's actual unmodelled repex in the first three years of the current regulatory control period is lower than its estimate for the last two years and significantly lower than its forecast for the forecast period. In its proposal, Ergon Energy did not demonstrate the need for this increased repex in its unmodelled asset categories.

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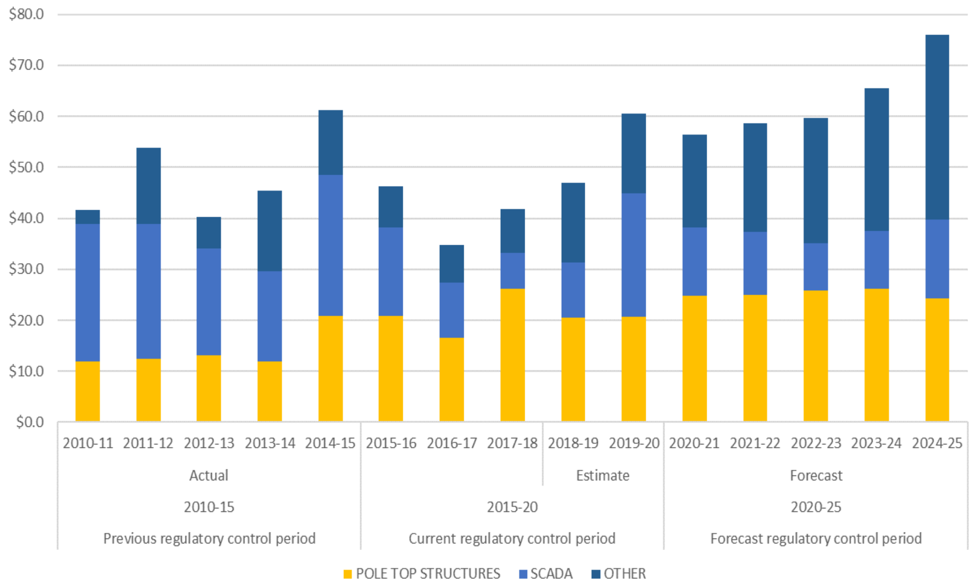
113 NER cl. 6.5.7(a).

114 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, pp. 48–49.

Figure A.6 – Ergon Energy's historical vs forecast unmodelled repex (by asset group) ($ million, 2019–20)



Source: Ergon Energy's recast CA RIN and reset RIN, and AER analysis.

Bottom-up engineering assessment

Trend analysis highlighted the pole top structure and 'other' asset groups as requiring additional assessment in our more detailed bottom-up assessment. This bottom-up assessment has highlighted concerns with both asset groups, particularly two programs in the 'other' group.

Low-voltage safety program

Ergon Energy has proposed $43.3 million for a low-voltage safety program, stating:

> In line with EQL's regulatory duty of care, there is an imperative to reduce the incidence of public shocks 'so far as is reasonably practicable' (SFAIRP). To do so, both Energex and Ergon Energy have defined targeted performance to Service asset related shocks and established annual LV services inspection and replacement programs to achieve the targets.[115]

The program recommends installing and monitoring network monitoring devices to minimise the risks of deteriorated neutrals, which can result in electrical shocks and tingles.[116] The devices monitor the low-voltage network, allowing faults to be detected and quickly repaired. This program is replicated in Energex's regulatory proposal for the 2020–25 regulatory control period. For a more detailed discussion on this program and our assessment, please refer to section A.4 of Energex's draft decision.

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115 Ergon Energy, *Strategic proposal – LV safety and network visibility*, January 2019, p. 3.

116 Ergon Energy, *Strategic proposal – LV safety and network visibility*, January 2019, p. 15.

Ergon Energy states that its current method of periodically inspecting assets for deterioration is insufficient due to an increasing level of electrical shocks in its network. It also states that “there are legislative and regulatory requirements for assuring safe delivery of electricity to the customers by reducing the risk to as low as reasonably practicable (ALARP)”.[117]

Ergon Energy has not sufficiently justified this proposed program. We have approved safety-related capex in previous decisions, reflecting the importance of funding to address safety risks. However, in this case:

- Ergon Energy has not provided sufficient material, including consideration against its current practices, to demonstrate that its proposed new capital program is required.
- Stakeholders have expressed similar concerns about the lack of options analysis to support the program.
- Ergon Energy's current program that addresses broken neutrals appears to be consistent with industry best practice and there is no evidence that it is not compliant with the relevant regulatory obligations. Furthermore, there has not been a change to regulatory obligations to necessitate this program.
- Our assessment of the program's costs and benefits based on the information provided suggests that the costs of the program may be grossly disproportionate to the benefits of mitigating the health and safety risks.
- Ergon Energy's recommended program does not solve the cause of the risk that it is trying to mitigate.

While Ergon Energy included evidence of deteriorated assets in its proposal documents, it did not include robust and quantified analysis to support the recommended program. We therefore requested the underlying analysis for this program to ensure that the costs of the program are not grossly disproportionate to the expected benefits. Ergon Energy did not provide this analysis, instead providing a least-cost options analysis that ignored the base case or counterfactual option. In response to information requests, Ergon Energy stated that it does not and will not quantify the cost of safety consequences, such as fatalities or injuries.[118] Further, when questioned what it considers a tolerable level of risk of electrical shocks, Ergon Energy stated it has zero tolerance for shocks.

In support of its program, Ergon Energy submitted legal advice from Minter Ellison regarding the interpretation of the safety legislation, the Electrical Safety Act (QLD) 2002, which mirrors the Work Health and Safety Act 2011. Minter Ellison stated that in assessing the concepts of SFAIRP and ALARP, the primary consideration should be the likelihood and degree of harm of a risk, and options to eliminate or reduce the risks.

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117 Ergon Energy, *Strategic proposal – LV safety and network visibility,* January 2019, p. 34.

118 Ergon Energy, *Response to information request 27,* May 2019, pp. 9–14.

After these factors are assessed, the costs of risk mitigation should be considered, including "whether the cost is grossly disproportionate to the risk."[119]

Minter Ellison submitted that, based on the evidence that "the likelihood of an electric shock from a neutral issue is significant" and "the potential consequences can be fatal:"[120]

> Any finding by the AER, which discounts Ergon Energy and Energex's forecast expenditure of the Neutral Program on the basis that it was unsupported by a cost-benefit analysis, would be a flawed finding, based on an incorrect understanding of the nature of the obligations created by safety legislation in the relevant jurisdiction.[121]

This conclusion does not give proper regard to the fact that in the event of a public shock, the likelihood of a serious consequence (i.e. a serious injury or a fatality) is extremely low. Based on the information provided, we could not find a single fatality or serious injury caused by low-voltage broken neutrals for the period 2011–12 to 2016–17.[122]

We conclude that when considering both the likelihood of an electric shock and the likelihood that the shock will cause a significant degree of harm, the current health and safety risks posed by broken neutrals are very low. Therefore, the costs of reducing this risk are a relevant consideration when assessing whether this program is reasonably practicable.

Minter Ellison also stated that a cost-benefit analysis is not required to assess prudency and efficiency of a business' proposed capex except where the proposed expenditure might be grossly disproportionate to the risk to be mitigated:

> Only if there is reason to believe that forecast expenditure would be grossly disproportionate to the risk involved would the absence of a cost-benefit analysis be a material consideration in determining that the expenditure was not prudent or efficient.[123]

Minter Ellison has not had regard to the relevance of the NER requirements for the AER to assess whether the capex proposed reflects prudent and efficient costs.[124] To ensure that proposed capex satisfies the capex criteria of the NER, the AER may seek evidence to help form an informed conclusion. The NER sets out several factors that the AER must have regard to when assessing the prudency and efficiency of a proposed capex, as well as any additional factors that the AER considers to be relevant.

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119 Australian Government, *Work Health and Safety Act 2011*, September 2018, s18. https://www.legislation.gov.au/Details/C2017C00305

120 Ergon Energy, *Legal advice to safety submission (public),* August 2019, p. 2.

121 Ergon Energy, *Legal advice to safety submission (public), August 2019*, p. 5.

122 Ergon Energy, *Response to information request 24,* May 2019, pp. 24–27.

123 Ergon Energy, *Legal advice to safety submission (public), August 2019*, p. 5

124 NER, cll. 6.5.7(a), 6.5.7(c)(1).

The Australian Competition Tribunal has commented that quantitative assessment is a general requirement when testing whether the chosen cost option satisfies the capex requirements:

> Ultimately, it is not so important whether the label "cost-benefit" is used to describe what is needed to demonstrate the economic efficiency directives required to demonstrate compliance with r 79(1)(a). What is more important is that the process employed be robust, and it must critically assess all available options for achieving the desired outcome, even if those options may not have been ones that were originally contemplated. There must be a dispassionate, objective and open mind brought to bear. The process must also examine the consequences of embarking on an option (or of not doing so), the costs attached to each option, and the ultimate return from them over their life, in present value terms. Although the process will have some qualitative features, it must invariably be a quantitative process.[125]

We agree with Ergon Energy that reducing safety risks is important and have approved safety-related capex in previous decisions. In many previous decisions, we have acknowledged that where capex is proposed to meet health and safety risks, it is reasonable for forecast costs to be higher than the benefits of mitigating those risks. In these cases, we reviewed the robustness of the analysis, including the disproportionality factors. As a result, we accepted costs that were higher, but not grossly disproportionately higher, than the benefits of mitigating the health and safety risks.

However, Ergon Energy has not sufficiently justified that it is seeking to reduce risk to a level so far as is reasonably practicable or that the costs of its safety project are not grossly disproportionate to the risks the projects are aiming to mitigate. EMCa supported this view, stating:

> Ergon Energy's risk framework includes consideration of ALARP and SFAIRP…. However, application of this framework in practice, including how ALARP has been assessed and achieved, is not evident from the justification statements or other supporting information provided in support of Ergon Energy's forecast expenditure.[126]

Other than reference to ALARP and SFAIRP in tolerability scale documentation, we were not provided with an explanation of how Ergon Energy makes its assessment for each of the projects and programs it has included in the proposed repex program. CCP14 also had concerns regarding the prudency of this program and Ergon Energy's lack of options analysis:

> Our concern is around the way the risk and prudent reaction has been portrayed, without some context around the meaning of 'as low as reasonably practicable'. In addition, we believe that the solution proposed - installing new-

[125] Australian Competition Tribunal, *Application by ATCO Gas Australia Pty Ltd [2016] ACompT 10*, July 2016, [278].

[126] EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, p. 25.

> technology network monitoring devices at a customer's premises, does not represent a full and fair assessment of the options available.[127]

Crucially, the proposed monitoring program does not solve the cause of the risk that Ergon Energy is trying to mitigate. EMCa and the Queensland Electrical Safety Office (ESO) also highlighted this point.[128] The ESO agrees with Ergon Energy that "neutral failure is an important issue to be addressed as current rates of failure are not acceptable."[129] It submitted that it supported network monitoring, but improved preventative practices were required in the first instance, including:

- engineering solutions to address causes of higher failure rates, such as in coastal areas
- increased standards, such as double-clamping
- increased and improved inspection practices
- determining safe service life in different environments and reducing average service line age.[130]

The ESO submitted that a holistic approach focused on prevention "should address other failure modes such as insulation integrity, line clearances and service line attachment strength which will not be detected by LV monitoring."[131] The ESO also considered that a reactive maintenance program may not be the most cost-effective approach to addressing LV safety risks:

> A reactive program driven by monitoring to detect failures may not be the most cost-effective way to address risks; i.e. bulk replacing old service lines street by street as a proactive maintenance activity is surely more cost effective then returning multiple times to address individual failures.[132]

Return to service

Ergon Energy proposed $44.8 million for a program to reactively replace substation assets that are expected to fail outside of planned replacement programs. Ergon Energy stated that due to asset failure, it spent approximately $13 million per annum between 2013–14 and 2017–18 on this category. To determine its forecast, Ergon Energy considered its historical average spend and lowered the forecast to reflect its focus on proactive replacement and the problematic assets that were replaced in the current regulatory period.[133]

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127 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 regulatory proposals,* May 2019, p. 11.

128 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure,* August 2019, p. 60.

129 Queensland Electrical Safety Office, *Feedback on Energex and Ergon Energy's regulatory submissions 2020–25*, p. 1.

130 Queensland Electrical Safety Office, *Feedback on Energex and Ergon Energy*'s *regulatory submissions 2020–25*, p. 2.

131 Queensland Electrical Safety Office, *Responses to AER questions regarding* EQ's *LV* safety *and* program, 28 June 2019, p. 3.

132 Queensland Electrical Safety Office, Responses to AER questions regarding EQ's LV safety and program, 28 June 2019, p. 3.

133 Ergon Energy, *Justification statement – Return to service replacement*, January 2019, p. 2.

Ergon Energy has not sufficiently justified the proposed amount as prudent and efficient, as the figure was not supported by modelling, cost-benefit analysis or options analysis. In addition, our modelled repex forecast is likely to include repex for modelled substation assets such as switchgear and power transformers that fail and need to be replaced reactively, as any historical failures and replacements will be captured in the historical calibration period. We therefore encourage Ergon Energy to report this expenditure against the respective modelled asset categories in its revised proposal reset RIN.

Substitute estimate

Given the lack of information, we were unable to derive a substitute estimate from our bottom-up analysis. In the absence of robust risk-based cost-benefit analysis, we have relied on trend analysis of historical costs as a primary indicator of future costs to determine our substitute estimate of unmodelled repex. Our substitute estimate of $204.9 million is based on Ergon Energy's actual unmodelled repex in the first three years of the current regulatory control period, prorated to five years.

Trend analysis indicates that Ergon Energy's proposal for unmodelled repex is materially higher than its actual and estimated expenditure for the current regulatory period. As noted above, under the capex factors, we are required to consider both past and expected expenditure.[134] Ergon Energy's expected expenditure for this regulatory control period ($230.4 million) is much closer to our substitute estimate than Ergon Energy's proposal. In addition, the substitute estimate is supported by our bottom-up analysis of Ergon Energy's low-voltage safety and return to service programs.

A.5 ICT capex

Information and communications technology (ICT) refers to all devices, applications and systems that support business operation. ICT expenditure 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.

Background

Until July 2016, ICT services for Energex and Ergon Energy were provided by the companies' jointly owned subsidiary, SPARQ Solutions. Costs for this service were recovered from each business through an 'asset usage fee', incorporated of depreciation of the assets constructed and interest-based borrowing required to fund the asset construction.

SPARQ became a 100 per cent subsidiary of EQ following the creation of the merged entity. EQ continues to use the asset usage fee established by SPARQ for the current regulatory control period. This treats ICT costs as an overhead for the distributors, which are allocated across capex and opex.

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[134] NER cl. 6.5.7 (e).

For the 2020–25 regulatory control period EQ will allocate assets in SPARQ to the fixed asset register and RABs of each business. Where assets are 'shared' (i.e. they cannot be specifically assigned to one of Energex or Ergon Energy), the costs will be allocated in accordance with the businesses' cost allocation methodology (CAM).

In this attachment, our ICT capex assessment only describes our draft decision for Ergon Energy. However, for the reasons outlined above, we have assessed EQ's total ICT capex forecast of $403.1 million together. Ergon Energy's proposal also presents forecast ICT capex including associated indirect costs. We have assessed these indirect costs as part of capitalised overheads and this section therefore discusses our direct capital costs assessment only.

Many stakeholders including CCP, QCOSS and ENA have requested us to closely examine EQ’s proposed ICT expenditure. These stakeholders have considered that the proposed investment is significant and have asked for clarity on the prudency and efficiency of the proposed amount.

A.5.1 Draft decision

Ergon Energy has not sufficiently demonstrated that its forecast ICT capex of $210.1 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have assessed the project documentation accompanying Ergon Energy's proposal and any further information provided by Ergon Energy. We have included an amount of $159.7 million for ICT capex in our substitute estimate, a 24 per cent reduction to Ergon Energy's forecast. Table A.3 summarises Ergon Energy's proposal for ICT capex and compares this to our draft decision.

Table A.3 – Draft decision on Ergon Energy's forecast ICT capex ($ million, 2019–20)

Category	Proposal	Draft decision	Difference
Recurrent ICT capex	60.7	52.4	-8.3
Non-recurrent ICT capex	149.4	107.3	-42.1
Total ICT capex	**210.1**	**159.7**	**-50.4**

Source: Ergon Energy's response to information request 63 and AER analysis.

A.5.2 Ergon Energy's proposal

Ergon Energy's proposal included an ICT capex forecast of $210.1 million.[135] This is $14 million lower than Ergon Energy's total actual and estimated ICT capex in the current regulatory control period. Ergon Energy's ICT capex forecast included $60.7

[135] Ergon Energy, *2020–25 regulatory determination RIN template*, January 2019, resubmitted version.

million for recurrent ICT programs and $149.4 million for non-recurrent ICT projects.[136][137]

Ergon Energy's recurrent ICT capex forecast of $60.7 million includes cyclical replacement of ICT devices and infrastructure, minor ICT changes to support safety initiatives, risk assessments, network growth to support new customers, electricity market changes and audit recommendations,[138] and other minor upgrades to maintain EQ's systems for continued serviceability.

Ergon Energy's non-recurrent ICT capex forecast of $149.4 million includes 18 projects. These projects are driven by the objective of replacing Energex and Ergon Energy's separate ICT systems with one consolidated EQ version. Some major replacement and consolidation projects include Geographic Information Systems, Network Operations Systems, Field Force Systems, and Customer Market Systems.

A.5.3 Reasons for draft decision

Consistent with our ICT expenditure assessment guideline consultation paper,[139] we have assessed recurrent ICT capex separately to non-recurrent ICT capex.

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 all businesses in the NEM, we have not undertaken benchmarking analysis in the draft decision.

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 draft decision 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. EQ provided historical expenditure for each recurrent ICT program,[140] which shows that EQ's total forecast expenditure is in line

[136] For the purposes of our assessment, we have treated the 18 projects for which supporting business cases and cost-benefit models were provided as non-recurrent ICT capex. All remaining capex has been treated as recurrent ICT capex.

[137] Ergon Energy, *Response to information request 2*, 13 February 2019.

[138] Ergon Energy, *ICT Plan,* January 2019, p. 45.

[139] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/ict-expenditure-assessment-review.

[140] Ergon Energy, *Response to information request 11,* April 2019.

with current period expenditure for these programs. From a top-down perspective, EQ's recurrent ICT capex appears to be a reasonable forecast of the prudent costs for this category of capex.

EMCa's review

While we acknowledge our top-down results, we have also had regard to EMCa's advice. EMCa's review identified that Ergon Energy's forecast is reasonable for all elements other than 'other minor application upgrades and updates'. EMCa observed that the proposed other minor application upgrades and updates capex is significantly higher than current period expenditure.

EMCa expects that Ergon Energy would adopt a risk-based approach to upgrading its applications. This includes deferring upgrades beyond the reference lifecycle, which it assumes that EQ has applied. However, Ergon Energy has not provided any indication that is has done so. EMCa therefore considers that Ergon Energy has not justified the proposed increase.[141] In the absence of any other evidence and having regard to EMCa's findings, we have reduced Ergon Energy's forecast for the 'other minor application upgrades and updates' by 50 per cent to align the forecast to current period actual levels.

Non-recurrent ICT capex

We have reviewed the information provided to support Ergon Energy's 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 Ergon Energy through information requests. We have also had regard to EMCa's bottom-up review.

We endorse the overall objectives/goals of the non-recurrent ICT program. However, Ergon Energy's non-recurrent ICT capex forecast is not a reasonable forecast of prudent and efficient costs and Ergon Energy is unlikely to deliver the program in the timeframe proposed. Below we discuss Ergon Energy's inclusion of additional contingency costs, the deliverability of its proposed ICT program and the findings of our business case review.

Contingency costs

Ergon Energy submitted that to obtain its final cost estimate included in the business case, baseline estimated project costs were multiplied by "the capital estimation accuracy factor"[142]. The capital estimation accuracy factor was based on the forecast confidence rating, and was:

- 1.1 (i.e. 1 + 10%) for projects with a 'High' estimated confidence rating
- 1.2 (i.e. 1 + 20%) for projects with a 'Medium' estimated confidence rating
- 1.3 (i.e. 1 + 30%) for projects with a 'Low' estimated confidence rating.

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141 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure*, September 2019, p. 86.

142 Ergon Energy, *Response to information request 25 (public),* 10 May 2019, p. 14.

For Ergon Energy, these additional costs account for $23.2 million, or 16 per cent of the proposed non-recurrent ICT capex forecast. We do not consider that including contingency costs is likely to result in the forecasts reflecting prudent and efficient costs. The estimation accuracy identified implies that there is an equal probability that a project will go below or above budget.

Therefore, over the entire portfolio of 18 projects, it would be expected that the overall over/underspend will be zero. EMCa also concurred with our findings from its review and recommended these contingency costs were removed from the capex forecast. We have excluded this amount from our substitute forecast for non-recurrent ICT capex.

Program deliverability

Overall, Ergon Energy's strategy of consolidation via replacement is prudent. Given the age of the systems, it is reasonable to assume that most systems will need to be replaced in the medium term. Consolidating the disparate systems to single EQ-wide systems will deliver multiple real benefits (i.e. avoid the 'double-up' of costs) and lead to future costs. EMCa supported our findings and concluded that "it is reasonable to assume that it will be operationally and commercially prudent to replace the nominated systems in the next RCP or shortly thereafter given the age of the systems and the cost reduction and efficiency benefits of consolidation or unification."

However, we do not consider that Ergon Energy will be able to deliver the program as proposed, and a prudent and efficient ICT program would not include all of the ICT projects proposed for the 2020–25 regulatory control period. The proposed program is large scale, complex and an interdependent program of works that impacts broadly across core IT systems and business processes. The risks of successful delivery of the program in the timeframe proposed, in terms of resourcing, implementation, business process change and the realisation of benefits appear high.

Submissions from CCP[143] and ECA's economic consultant Dynamic Analysis[144] raised concerns with Ergon Energy's ability to effectively deliver the proposed program of works over the forthcoming regulatory control period. Ergon Energy's ICT Plan shows the indicative schedule of its proposed ICT program.[145] Its non-recurrent ICT portfolio is comprised of five streams where each is generally categorised as a series of interdependent projects delivered in sequence. It is evident from this figure that Ergon Energy has forecast a large and complex series of works.

Each business case outlines the programs, projects or business activities that the project is dependent on. It is clear how interdependent this program of works is from review of these documents. However, as EMCa notes,[146] not all of the interdependencies are apparent.

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143 CCP14, *Submission on Ergon Energy's regulatory proposal 2020–25,* 31 May 2019, p. 19.

144 Dynamic Analysis, *Technical regulatory advice to the ECA – Review of 2020–25 regulatory proposals,* 5 June 2019, p. 48.

145 Ergon Energy, *7.007 ICT Plan – Figure 4*, January 2019, p. 17.

146 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure, September* 2019, p. 79.

Therefore, the delay of one project would likely lead to corresponding delays to dependent projects. In particular, delays to projects early in the regulatory control period would lead to delays to the remaining program of work, pushing planned work in the final years of the period into the 2025–30 regulatory control period. This risk is further exacerbated by Ergon Energy's assumption that some projects will start before necessary projects are completed (i.e. the Customer and Market Systems stream). EMCa also highlighted delivery risk as a significant issue. EMCa considered that:

- With a number of large, complex and dependent projects, the phasing becomes critical. However, Ergon Energy's phasing is back-to-back, which dramatically increases the risk profile associated with delivery.
- The Roadmap view does not show evidence of Hypercare windows between dependent projects to allow for any rework or settling in of the new technologies.
- In a number of dependent projects, Ergon Energy has assumed an overlap of project-and project-start times than can considerably increase the risk of a total portfolio overrun.
- Ergon Energy has not adequately considered or factored in time contingency for the above effects.
- Given the complexities, dependencies and the aggressive phasing and schedules for the 2020–25 portfolio, it is likely there will be material program slippage.[147]

Our analysis of Ergon Energy's current ICT program suggests that it does not consistently deliver its ICT programs as forecast. For example, it has underspent by nearly $27 million (15 per cent) overall for the first four years of the current period. In addition, in the four-month period between January and May, Ergon Energy revised its estimated ICT capital spend for the 2018–19 year down by 24 per cent.[148]

EMCa stated that Ergon Energy provided reports that found that five of the 13 projects related to the current ERP EAM renewal current period project are between 10–20 per cent behind schedule, with one other more than 20 per cent behind schedule as of May 2019. EMCa also noted that based on Ergon Energy's performance in the 2015–20 regulatory control period, and its understanding of the complexities involved in the in-flight projects, there is a material risk that Ergon Energy will not be able to complete its 2015–20 program of work in this period. If there is slippage, EMCa stated that delivery risk for Ergon Energy's 2020–25 ICT portfolio is likely to increase.[149]

Business case review

Overall, the business cases generally provide the information we would expect. However, aspects the business cases lack include:

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147 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure*, *September* 2019, pp. 80–82.

148 Ergon Energy, *EMCa site visit – ICT proposal discussion*, 17 May 2019.

149 EMCa, *Review of aspects of Ergon Energy and Energex's forecast capital expenditure*, September 2019, p. 81.

- Ergon Energy has not adequately demonstrated the need for replacement by the time proposed. Dynamic Analysis questioned whether Ergon Energy's assumed timings were optimal:

> Our review of the ICT plan suggests that a key driver of renewal is to transition existing systems onto a unified enterprise platform. This raises the question of whether the assets are being replaced before the end of life to further this strategy.[150]

- Ergon Energy's counterfactual 'do-minimal' option has not been adequately considered and the costs of this option have not been evidenced.
- The options analysis is insufficient for many projects because deferral has not been considered. There may be opportunities for Ergon Energy to prudently defer aspects of the program and implement a program that is more likely to be delivered over the period.

Benefits of the non-recurrent ICT program

In the NPV models provided, Ergon Energy outlines the currently identified and directly attributable financial benefits forecast to be achieved from each ICT project. Our review highlighted that Ergon Energy has forecast cost saving benefits for 17 of the 18 non-recurrent projects (all except the cyber security project). Overall, Ergon Energy is forecasting $19.8 million of directly attributable savings over the 2020–25 regulatory control period.

However, Ergon Energy has not provided evidence to demonstrate the benefits quantified are reasonable forecasts of the likely outcomes of these projects. Further, we have found that while Ergon Energy has made a 'top-down' productivity adjustment to its overall expenditure forecast to reflect the benefits of the ICT program, it has not demonstrated a tangible link between these adjustments and its ICT forecast.

Benefit calculation

Ergon Energy provided a spreadsheet[151] that outlined the assumptions underpinning the claimed financial benefits for each project. It explained that the forecast yearly cost saving benefit for each project was quantified through a calculation of forecast productivity areas and the financial value for each saving area. Ergon Energy forecast that these benefits will lead to savings in capex, opex and total overheads.

Although Ergon Energy provided further information to support its savings,[152] it has not provided sufficient evidence to demonstrate that the assumed cost-savings benefits are reasonable forecasts of the likely outcomes of these projects. Information, such as a consultant report or identified benefits from similar previous historical projects, would support the benefits quantified.

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150 Dynamic Analysis, *Technical regulatory advice to the ECA – Review of 2020–25 regulatory proposals*, 5 June 2019, p. 49.

151 Ergon Energy, *Response to information request 1*9, 15 April 2019.

152 Ergon Energy, *Response to information request 2*9, 14 May 2019.

In the absence of evidence that demonstrates these assumptions underlying the benefit calculations are reasonable, we have no confidence that these are reliable estimates of the likely savings to be achieved from the projects.

Timing of the benefits identified from the non-recurrent ICT program

Ergon Energy submitted that the timing realisation of the forecast savings is dependent on the sequencing, dependencies and delivery timeframes of each benefit. Ergon Energy stated that it has assumed that 50 per cent of the forecast per annum saving is to be achieved in the year following completion of the project, after which 100 per cent of the saving will be achieved. This appears to be a reasonable assumption.

Ergon Energy's calculations show that the majority of the cost savings forecast to be delivered from the ICT program will be delivered in the 2025–30 regulatory control period, rather than the forecast period. Ergon Energy forecasts $77 million in savings over the 2025–30 period, compared with $19.8 million in the 2020–25 period. We expect that Ergon Energy will incorporate benefits from the completed program into its proposed forecast expenditure for the 2025–30 regulatory control period.

Incorporation of claimed benefits into the overall expenditure forecast

We asked Ergon Energy to show how it had accounted for the forecast cost savings attributable to the ICT program. Ergon Energy submitted that its forecast 10 per cent savings for overheads and 3 per cent improvement to its program of works delivery reflect these ICT program benefits plus further savings.[153]

We have investigated the extent to which these benefits have been correctly accounted for in the expenditure forecasts. While we recognise that these ‘top-down’ adjustments have been made to the forecast, it is unclear from the information available what contribution the non-recurrent ICT program makes to these productivity targets. Ergon Energy has not sufficiently shown that all of the claimed benefits of the non-recurrent ICT program are reflected in its proposal.

Ergon Energy's analysis shows that the benefits from the ICT program do not become material until the second last year of the 2020–25 regulatory control period, with the majority of benefits occurring in the 2025–30 regulatory control period. This contrasts with the assumed timing of the adjustments made to the forecast, which apply equally from the beginning of the 2020–25 regulatory control period. For example, Ergon Energy has proposed a 2.58 per cent opex productivity in each year of the regulatory control period. Therefore, there appears to be a disconnect between the non-recurrent ICT program schedule and the realisation of the proposed productivity adjustments.

We consider that based on the information available, it is not clear that the proposed ICT program is a fundamental input to these productivity benefits. We anticipate that in its revised proposal, Ergon Energy will more clearly demonstrate the link between its ICT program and these productivity benefits.

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[153] Ergon Energy, *Response to information request 18 (public)*, 15 April 2019, p. 3.

Draft decision on non-recurrent ICT capex

EMCa advised that a prudent and efficient level of investment in non-recurrent ICT capex represents a reduction of 10 to 15 per cent to Ergon Energy's forecast (once contingency costs have been removed). Based on this advice, our substitute estimate applies a 15 per cent reduction to forecast non-recurrent capex, as this is the number within EMCa's range that aligns the forecast closest to EQ's combined historical expenditure.

A.6 Property capex

Property expenditure for Ergon Energy relates to the maintenance, refurbishment and optimisation of offices, operational depots, warehouses, training facilities and other specialist facilities. The indirect costs associated with the provision of property assets have been assessed as part of overheads. The costs below refer to 'direct' capital costs only.

Property services for both Ergon Energy and Energex is undertaken by a single entity specifically responsible for optimising and maintaining the combined property portfolio in Queensland. The property capex proposals for Ergon Energy and Energex are therefore comprised of common projects where costs have been allocated to each business.

ECA questioned the basis for the proposed rebuild of the training facility compared to refurbishment.[154] ECA considered that the case had not been made to show that the existing facility is non-compliant, and that the costs of refurbishing should be lower than rebuilding. Origin Energy also encouraged us to scrutinise Ergon Energy's property capex forecast.[155]

A.6.1 Draft decision

Ergon Energy has not demonstrated that its property capex forecast of $128.6 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included an amount of $56.5 million for property capex in our substitute estimate, a 56 per cent reduction to Ergon Energy's forecast. Table A.4 summarises Ergon Energy's proposal for property capex and compares this with our draft decision.

Table A.4 – Ergon Energy's property capex forecast and our draft decision ($ million, 2019–20)

Category	Proposal	Draft Decision	Difference ($)
General property programs	**$43.6**	**$43.6**	**-**
Base Capital	*$36.8*	*$36.8*	-
Minor Capital Works	*$6.7*	*$6.7*	-

154 Energy Consumers Australia, *Submission on Ergon Energy's regulatory proposal 2020–25*, 5 June 2019.

155 Origin Energy, *Submission on Ergon Energy's regulatory proposal 2020–25*, 31 May 2019.

Category	Proposal	Draft Decision	Difference ($)
Major Projects	**$57.7**	**$2.6**	**-$55.1**
Maryborough Strategy	*$26.5*	*$0.0*	*-$26.5*
Brisbane Training Facilities	*$8.8*	*$0.4*	*-$8.4*
Townsville Training Facilities	*$3.0*	*$0.2*	*-$2.9*
Banyo	*$8.5*	*$0.0*	*-$8.5*
Data Centres Strategy	*$6.5*	*$0.0*	*-$6.5*
Brisbane Office	*$4.4*	*$2.0*	*-$2.4*
Carry-over work	**$7.2**	**$7.2**	**-**
Cairns Operational	*$7.2*	*$7.2*	*-*
Other programs	**$20.1**	**$3.2**	**-$16.9**
Security Program	*$18.1*	*$1.3*	*-$16.9*
Control Centre Strategy	*$0.8*	*$0.8*	*-*
Asbestos Removal Program	*$1.1*	*$1.0*	*-*
Total	**$128.6**	**$56.5**	**-$72.0**

Source: Ergon Energy's response to information request 63 and AER analysis.

A.6.2 Ergon Energy's proposal

Ergon Energy’s proposal included a property capex forecast of $128.6 million.[156] This represents a 4 per cent decrease from Ergon Energy’s actual and estimated property capex of $133.8 million over the 2015–20 regulatory control period.

A.6.3 Reasons for draft decision

General property programs

Ergon Energy proposed:

- $36.8 million for Base Capital (“capital works required to address safety, compliance and operational issues” at depots, offices, residences and other EQ sites)[157]
- $6.7 million for Minor Capital Works (“replace, upgrade and renew aged, dilapidated minor and regional depots with fit-for-purpose, efficient minor facilities”).[158]

Ergon Energy submitted that the forecasts have been made based on analysis of historical spend with several efficiencies implemented to ensure the minimum

156 Ergon Energy, *2020–25 regulatory determination RIN template (resubmit)*, January 2019.
157 Ergon Energy, *Property services strategy*, January 2019, p. 41.
158 Ergon Energy, *Property services strategy*, January 2019, p. 32.

expenditure required to maintain a safe and compliant portfolio. We reviewed Ergon Energy's forecasting methodology and governance arrangements for this expenditure.

Given the nature of these works, costs for this category will likely reduce in the next regulatory control period, given the significant property works undertaken in the 2015–20 regulatory control period. We asked Ergon Energy to provide historical expenditure for these two programs.[159] Our analysis identified that the proposed expenditure is significantly lower than historical expenditure for these programs (53 per cent reduction for Ergon Energy relative to average historical expenditure from 2011–12).

On this basis, we are satisfied that that Ergon Energy's forecasts reflect the drivers of these programs and therefore that these are reasonably reflective of the efficient costs of a prudent operator.

Major projects

In addition to the base property work, Ergon Energy has proposed five major projects for the forecast regulatory control period. Ergon Energy provided business cases and cost-benefit analyses for each major property project. We have reviewed these documents and where required, sought further information from Ergon Energy through information requests.

Incorrect present value cost calculation

For each project, Ergon Energy undertook an assessment of each option's present value. In doing so, Ergon Energy estimated the likely capex and opex costs required under each option. This analysis generally considers the trade-off between higher capex and the forecast lower opex and other costs at these sites. No analysis was undertaken to quantify the other benefits claimed for each option.

However, in doing this analysis, Ergon Energy did not calculate present values correctly. Ergon Energy calculated the present value of each option by summing costs in nominal dollars, rather than summing the costs as their discounted values (i.e. future costs in 'present day' terms). Table A.5 shows the present values claimed in the business cases and the present values obtained when costs are discounted. The highest present value (or least cost) option is bolded under each calculation method.

Table A.5 – Claimed and actual present values for major projects

	Option	Brisbane training	Townsville training	Banyo	Data centres strategy	Brisbane office
	Base Case	-$27.5	-$9.8	-	-$39.1	-$739.7
Claimed	Option 1	**-$24.8**	**-$9.5**	-$34.5	**-$21.7**	-$716.6
	Option 2	-$29.2	-$15.0	**-$23.7**	-	**-$685.8**
Actual	Base Case	**-$14.0**	**-$5.0**	-	-$23.5	-$426.5

159 AER, *Information request 9,* March 2019.

Option	Brisbane training	Townsville training	Banyo	Data centres strategy	Brisbane office
Option 1	-$18.1	-$6.6	-$25.3	**-$15.3**	-$417.4
Option 2	-$14.5	-$10.1	**-$24.3**	-	**-$409.1**

Source: Ergon Energy's response to information request 3 and AER analysis.

As shown in Table A.5, when expenditure values are discounted, the highest ranked present value results change for the Brisbane and Townsville Training Facilities projects. For these projects, the base case is the highest present value option. As such, Ergon Energy has not demonstrated that its chosen option for these sites represents the most prudent and efficient outcome. Instead, Ergon Energy's analysis would appear to demonstrate that the 'base case' would instead be the lowest cost option.

Ergon Energy has not properly accounted for the benefits of each option. Without benefit quantification for each option at these sites, its cost analysis alone cannot be used as the basis for the proposed investment decisions. Ergon Energy appears to undertake its benefit assessment by providing a ranking of each option against its critical operational criteria on a scale of one to five. This analysis is insufficient to accurately demonstrate the relative benefit of each option. Without quantification, the true value of the incremental benefits of the options are unknown.

Opex savings do not appear to have been incorporated into forecast opex

Each of the five projects identify opex savings resulting from the proposed expenditure. This includes forecast reductions to ongoing maintenance costs, rent costs, land tax, etc. Analysis of each business case identifies that Ergon Energy is forecasting opex to reduce by a total of $13.1 million over the forecast regulatory control period. We asked Ergon Energy to explain how these savings were accounted for in the opex forecast. Ergon Energy responded:

> There were no step changes in opex identified in our forecasts and therefore no step changes included in the Base Step Trend modelling used to prepare our opex forecast. However, the top down management savings that we have committed to have been applied to our opex forecast through a productivity adjustment of 2.58% for Ergon Energy.[160]

However, Ergon Energy did not explain how these opex reductions contribute to this 2.58 per cent reduction. This is a capex opex trade-off[161] and does not relate to productivity improvements. For example, under the Brisbane Office project, Ergon Energy proposes capex to enable the disposal of the Ann St depot, which allows for the avoidance of the associated opex costs at this site. We expect that if Ergon Energy decides to repropose each major property project as part of its revised proposal, it will

160 Ergon Energy, *Response to information request 9*, 27 March 2019, p. 17.

161 NER, cl. 6.5.7(e)(7).

adjust its forecast opex by including a negative step-change to account for the expected opex savings these projects will generate.

Concerns specific to each major project

Maryborough

As noted above, when the present value calculation is corrected, the base case (continue business as usual) is the highest present value (least cost) option. As such, Ergon Energy has not demonstrated the prudency and efficiency of its proposed solution. In addition, we have identified that:

- Ergon Energy has claimed building non-compliance as a serious issue to address at the current Searle St site. However, given this concern, Ergon Energy has not explained why it spent nothing in the current period while continuing its operation in violation of state building regulations (Ergon Energy was provided with an allowance of $38.9 million for this work in the current regulatory control period).[162] Further, the Dilapidation Report does not identify material non-compliance at Searle Street. Ergon Energy's claim of non-compliance has not been supported by evidence.

- Ergon Energy has also submitted that the base case option "does not address the operational inefficiencies of the depot particularly with regards to office accommodation, field delivery and pedestrian and vehicle traffic."[163] These claimed efficiency improvements have not been quantified or evidenced to warrant the proposed expenditure.

- Ergon Energy assumed that under its chosen option, Searle St depot opex costs will reduce to $250000 upon project completion (more than a 50 per cent reduction). Ergon Energy submitted that this figure was based on the average costs of three other minor hubs.[164] However, in regards to the Searle St depot, Ergon Energy submitted that:

  > "The total site area for Searle Street which includes the adjoining site is 6.14ha. This is easily the largest site in terms of square meters compared to all the other minor hubs within the portfolio and well above the average square meter allocation of all the minor hubs combined (average size is 1.75ha)."[165]

- We would consider that the opex cost of a site would be in proportion to its size. Therefore, given the size of this depot, opex costs may not reduce to the level assumed, lowering the actual NPV of the investment relative to the base case.

- Ergon Energy did not include the forecast value of disposal of the Adelaide St office into the PTRM.[166] Ergon Energy submitted that this will be done as part of its revised proposal.[167]

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162 Ergon Energy, *Property business case – Maryborough,* January, 2019, p. 4.

163 Ergon Energy, *Property business case – Maryborough,* January, p. 13.

164 Ergon Energy, *Response to information request 9,* 27 March 2019, p. 17.

165 Ergon Energy, *Property business case – Maryborough,* January, p. 5.

166 Ergon Energy, *Response to information request 9, 27 March 2019,* p. 21.

167 Ergon Energy, *Response to information request 31,* 06 July 2019.

Based on the information provided, Ergon Energy continuing ‘business as usual’ is the most prudent and efficient option. Under this option, Ergon Energy has identified a capital cost of $20 million. Ergon Energy has not been able to provide any evidence to demonstrate that this is prudent and efficient expenditure. Ergon Energy submits that this reflects high-level cost estimates of the capital investment required as a minimum to address existing non-compliance at the Maryborough Depot.[168]

The Dilapidation Report provided for this site only identified one non-compliance issue, that being for a disabled toilet.[169] We also note that Ergon Energy has explained that $1.2 million of investment is planned for 2019–20 to “address a number of high priority non-compliances at the Maryborough site.”[170] On this basis, we do not accept the efficiency of EQ’s assumed base case amount. As such, we have not included this project in our substitute estimate.

Training facilities

Ergon Energy submitted that its Brisbane and Townsville training facility have been identified as not being fit-for-purpose and is not achieving asset optimisation. After we make corrections to the present value calculations, the data shows that the base case (continue current operations) is the most prudent and efficient option for the Brisbane and Townsville training facilities.

In addition, Ergon Energy stated safety and compliance, reduction in operational and maintenance expenditure, and property asset optimisation as drivers for these projects. However, it has not provided evidence, such as quantifying the business costs and risks, to support its claims. Ergon Energy also has not identified low-cost solutions to address the issues identified as part of its option development, as we would expect in a robust business case. We also disagree with Ergon Energy's modelling assumptions:

- the escalation rate applied to opex costs and annual preventative maintenance costs in the base case are unreasonably high
- the opex reduction in both its cost and benefit assumptions in the preferred option for Townsville have been double-counted, which incorrectly inflated the present value of the preferred option relative to the base case
- the expected costs and benefits are generally not quantified or supported by evidence.

Therefore, Ergon Energy's base case options are the most prudent and efficient options for both projects. For the Brisbane training facility base case, Ergon Energy has identified $0.4 million for a number of minor works. This amount appears reasonable and we have therefore included this amount in our substitute estimate.

For the Townsville training facility base case, Ergon Energy included work relating to asbestos removal, fire code compliance work, PWD disability compliance, and

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168 Ergon Energy, *Property business case – Maryborough,* January, p. 13.

169 Ergon Energy, *Response to information request 31,* June 2019, p. 8.

170 Ergon Energy, *Commercial dilapidation report,* June 2019, p. 39.

structural repair work. However, EQ has a separate asbestos removal program that covers all asbestos removal needs, and it also has a separate forecast for base capital and upgrade programs that covers depot minor capital works.[171]

Therefore, most of the capital cost items included in the base case are covered by the base capital and upgrade programs. In addition, the forecast $0.2 million capital work for the sagging beam and fire code compliance is reasonable. We have therefore included these specific costs in our substitute estimate.

Banyo

Ergon Energy has not demonstrated the prudency and efficiency of this project or undertaken an economic assessment of a 'do-nothing' option. Ergon Energy submitted:

> Due to the extent of non-compliances of the current site, no amount of capital investment will rectify and address them. Due to the significance of the non-compliances and possible safety, operational and compliance risks and potential consequences the base case is not considered a feasible option.[172]

However, we expect that Ergon Energy would present evidence to support the above claims and quantify the business costs and risks. While several issues exist at the site, Ergon Energy has not presented the solutions and costs to resolve those issues.

We asked Ergon Energy to provide the quantified benefit associated with addressing each operational issue. In response, Ergon Energy submitted that it would provide this analysis by 21 June 2019,[173] but no further information was provided. As a result, Ergon Energy has not demonstrated that the operational efficiency benefits justify the cost of the proposed investment.

We asked for further information regarding the non-compliance at this site. Ergon Energy submitted that short-term measures have been put in place and safe staff behaviour have been sufficient to address non-compliance. As such, Ergon Energy has not demonstrated why continuing its current operations is not a viable option for the forecast regulatory control period.

In addition, Ergon Energy has not undertaken timing sensitivity study. We asked Ergon Energy whether the timing for this project is set to achieve the best economic outcomes.[174] Ergon Energy submitted that the proposed phasing is indicative only and has been planned in accordance with the existing lease expiry. This demonstrates that the timing has not been optimised for maximising economic benefit.

Maintaining manufacturing capacity in the workshop within a network's core business is in contrast to common industry practice. Ergon Energy has not demonstrated that this proposed expenditure represents the most effective way to support its operations.

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171 Energex, *Response to information request 3*, 20 February 2019, p. 18.

172 Ergon Energy, *Property business case – Banyo workshop*, January 2019, p. 12.

173 Ergon Energy, *Response to information request 31*, 6 June 2019, p. 7.

174 AER, *Information request 31*, May 2019.

Ergon Energy has stated that it is exposed to risks in land lease expiries, rent reviews and other market driven costs. These are BAU risks that any business needs to manage and therefore does not justify owning a new site. Based on the information provided, Ergon Energy has not supported the need for capital investment at this site.

Data centres strategy

Ergon Energy stated that its data centre is required to comply with the Telecommunications Infrastructure Standard for Data Centres (ANSI/TIA-942). However, the level chosen by Ergon Energy is not consistent with common industry practice. Further, we are not aware that any Australian electricity network's data centre is required to meet this standard.

Ergon Energy has not provided any quantitative assessment to demonstrate a need for the investment. Ergon Energy's options analysis only investigated internal solutions. It has not considered the costs and benefits of other viable options such as outsourcing. As a result, there may be more prudent and efficient solutions than those considered by Ergon Energy.

EQ's options analysis has only investigated internal solutions. It has not considered the cost and benefit of other viable options such as outsourcing to commercial data centre services. As such, there may be alternative solutions that may be more prudent and efficient than Ergon Energy's chosen option.

Ergon Energy also appears to have bundled the SCADA facility requirement and data centre expenditure together. These two facilities provide different functions and the expenditure requirements are different. This approach makes it difficult to assess the merits of individual option components for the two separate and different business needs.

The Life Cycle Plan[175] shows that the asset condition assessment and plant asset renewal and replacement was prepared in 2012. We do not consider it is prudent to forecast a major investment based on an asset assessment that was conducted seven years ago.

Ergon Energy did not provide evidence to support its assumed $13.6 million capital cost for the Base Case option, which was forecast seven years ago and may no longer be a reliable estimate. Ergon Energy has also not included the ongoing capital cost of the building in its preferred option, which biases the options analysis.

Brisbane office

The only benefit identified in Ergon Energy's present value assessment is the avoided opex costs at Ann St. While we anticipate that other claimed benefits such as a more efficient floor space and improved team interactions should lead to efficiency gains and therefore opex reductions, Ergon Energy has not quantified these additional benefits. In addition, only one of Ergon Energy's cost forecast relates to the relocation of

[175] Ergon Energy, *Response to information request 31*, 6 June 2019.

employees to Ann St and Ergon Energy has not demonstrated that the additional costs are required.

- 'Newstead major capital upgrade' of the cost forecast is to consolidate all Brisbane CBD staff in Newstead to relinquish other lease sites. From a cost-benefit perspective, these costs are justified as the benefits clearly outweigh the costs.
- The 'Newstead capital works' costs are an allowance for video conferencing facilities, security, fixtures and fittings, changing accommodation requirements such as meeting rooms, amenities, and workstation refurbishments. EQ has provided no evidence to demonstrate need or benefit of these costs. In addition:
    - video conferencing costs are funded separately through the ICT capex budget[176]
    - minor capital works is a separately forecast item.

Ergon Energy's model included costs up to year 2035. However, if years 2036 to 2038 are included as they are for some other property projects, then Ergon Energy's chosen option would cost materially more than the base case. As a result, we do not accept the proposed amount. We have included $2.0 million to enable staff at Anne St to be relocated to Newstead in our substitute estimate.

Carry-over work

Ergon Energy has proposed $7.2 million to complete project work underway in the current period. These costs are to be incurred in the first year of the forecast forthcoming period. Given the nature of this work, we have accepted this expenditure as part of our draft decision.

Other programs

Security program

Ergon Energy has not demonstrated the need, prudency and efficiency of this program. It considers that this program is required to respond to a regulatory obligation. However, these requirements have not been identified. In addition, Ergon Energy has not demonstrated that its proposed program responds to the requirements of this obligation in the most prudent and efficient way. We therefore do not accept Ergon Energy's forecast.

Ergon Energy's proposal did not include a detailed business case for this program. However, in response to an information request, it provided a revised business case that we have used as the basis for our assessment.[177]

Ergon Energy submitted that its proposed security program is based on compliance with the Draft Queensland Government Protective Security Framework Policy (QGPSFP). This framework is based on the Protective Security Policy Framework

[177] Ergon Energy, *Property services – Security strategy (public),* 4 June 2019.

(PSPF), which is the federal guideline. Ergon Energy submitted that it expects this policy will be in place and mandatory prior to the start of the forecast regulatory control period. The supporting document also outlines that preventing theft (particularly copper theft) is a driver of the program.

We asked Ergon Energy to provide historical expenditure on property security.[178] Our analysis identified that Ergon Energy's forecast is on average, nearly 15 times higher than average actual costs of the past 10 years. Given this forecast significant increase, we reviewed the evidence provided to demonstrate the prudency and efficiency of this program. Overall, Ergon Energy did not provide any evidence to demonstrate that it will be required to comply with a regulatory obligation in the forecast regulatory control period.

In addition, Ergon Energy did not provide the QGPSFP or explain what this policy requires it to do. Ergon Energy also did not demonstrate that implementing its proposed works represents the most efficient security measures and it did not demonstrate that any change would result in non-compliance. It has not identified the compliance gaps and then demonstrated its proposed security controls as the most prudent and efficient solution.

In the absence of a clear existing regulatory obligation, forecast capex must maintain the quality, reliability and security of supply of services.[179] Rather than meeting these requirements, Ergon Energy's proposed capex is to augment the current security controls at each site due to a revised risk appetite. We therefore consider that this program requires a regular business case assessment. We identified the following issues with the business case provided:

- EQ's merger occurred in July 2016. Given the identified need, it is unclear why nothing has been done during the current regulatory control period.
- Ergon Energy did not complete any cost-benefit assessment to justify the proposed expenditure. It submitted that it expects that the program will deliver similar benefits as the Energex program.[180] However, the cost-saving benefits attributed to the Energex program to date do not justify the proposed expenditure from a cost-benefit perspective.
- Ergon Energy based its options assessment against six predetermined ‘critical operational criteria’. It assessed each option against each of these objectives by rating them on a scale of 1 to 5. This is an insufficient economic options assessment.

Therefore, Ergon Energy has not demonstrated that the increase in property physical security capex is required. We have included $1.3 million for property security capex period in our substitute estimate of total capex, which is based on Ergon Energy's historical capex for this program. This amount is sufficient for Ergon Energy to replace any existing assets that reach end of life over the forecast regulatory control period.

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178 Ergon Energy, *Response to information request 9,* 27 March 2019.

179 NER, cl. 6.5.7(a)(3).

180 Ergon Energy, *Property services strategy,* January 2019, p. 36.

Control centre strategy and asbestos removal

Ergon Energy proposed $1.9 million for two other property programs (control centre strategy and asbestos removal). On the basis of our review, we are satisfied that these projects reasonably reflect the costs of a prudent operator. We have therefore included this amount in our substitute estimate of total capex.

A.7 Other non-network capex

Other non-network capex includes fleet, plant, tools and equipment. The largest component of this category is fleet, which covers expenditure for purchasing new vehicles and related items, including mounted plant. This can be divided between 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

Ergon Energy has not shown that its other non-network capex forecast of $160.7 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included an amount of $137.5 million in our substitute estimate of total capex. This is a reduction of $23.1 million (14 per cent). We are satisfied that our substitute estimate would form part of a total capex forecast that reasonably reflects the capex criteria. Table A.6 summarises Ergon Energy's proposed fleet, plant and equipment direct capex forecast and compares this to our draft decision.

Table A.6 – Draft decision on Ergon Energy's forecast fleet, plant and equipment direct capex ($ million, 2019–20)

Category	Proposal ($)	Draft decision ($)	Difference ($)
Total	$160.7	$137.5	-$23.1

Source: Ergon Energy's reset RIN and AER analysis.

A.7.2 Ergon Energy's proposal

Ergon Energy's proposal included $160.7 million for other non-network capex. Drivers of Ergon Energy's other non-network capex forecast are the large proportion of EWPs and generators requiring replacement, offset by its decision to lengthen the replacement cycle for light commercial vehicles and to continue to extend life for its plant.[181]

Given Ergon Energy's changed CAM and treatment of indirect costs, we compared Ergon Energy's forecast direct fleet, plant and equipment capex against estimated

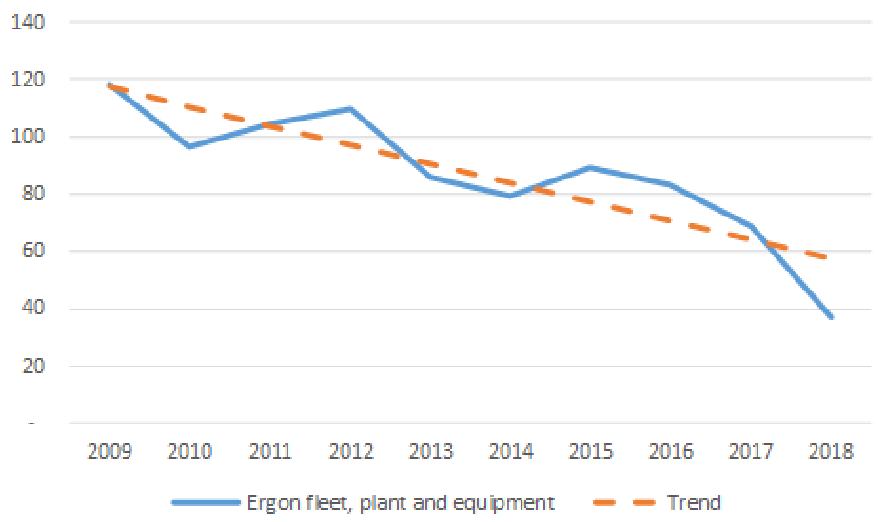
[181] Ergon Energy, *Regulatory proposal 2020–25,* January 2019, p. 77.

capex for 2018–19 and 2019–20. On an average yearly basis, Ergon Energy has forecast a 4.2 per cent increase.[182]

A.7.3 Reasons for draft decision

Ergon Energy's service life and unit rate assumptions in Ergon Energy's fleet model exceed efficient costs. From a top-down perspective, there has been a downward trend in overall fleet, plant and equipment capex for Ergon Energy (see Figure A.7).

Figure A.7 – Ergon Energy fleet, equipment and tools capex (as reported, using previous CAM and treatment of indirect costs) ($ million, 2019–20)

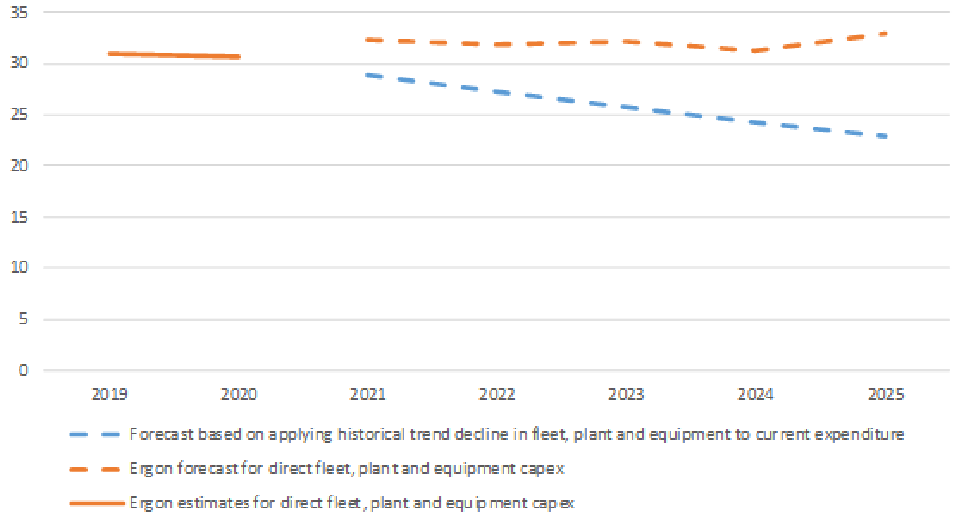


Source: Ergon Energy's recast CA RIN data and AER analysis.

Applying this trend to Ergon Energy's estimates for direct fleet, plant and equipment capex from 2019–20 (which use the same CAM and allocation of indirects as the forecasts), Ergon Energy forecasts expenditure to rise 20 per cent above trend (see Figure A.8).

[182] Ergon Energy, *Regulatory determination RIN 2020–25,* January 2019.

Figure A.8 – Ergon Energy direct fleet, equipment and tools forecast compared with trend (using new CAM and treatment of indirect costs) ($ million, 2019–20)



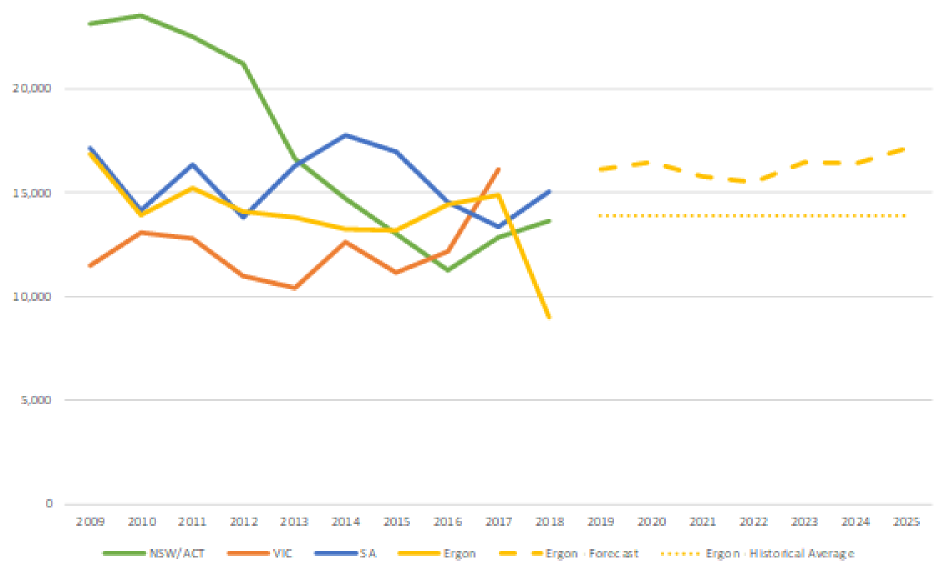
Source: Ergon Energy's reset RIN and AER analysis.

Stakeholders, including CCP and Origin, identified the forecast increase in this category or asked us to investigate it.[183] Dynamic Analysis considers a 20 percent reduction is appropriate across EQ for property, fleet and plant, and asked us to compare fleet per field worker with other distributors.[184] On a per employee basis, Ergon Energy's motor vehicles' totex is forecast to increase (see Figure A.9).

183 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 regulatory proposals,* 31 May 2019, p. 8; Origin Energy, *Submission on Ergon Energy's regulatory proposal 2020–25*, 31 May 2019, p. 2.

184 Dynamic Analysis, *Technical regulatory advice to the ECA review of 2020–25 regulatory proposals Energex and Ergon Energy,* 31 May 2019, p. 50.

Figure A.9 – Motor vehicles totex per employee by state ($2019–20)



Source: Ergon Energy's reset RIN and AER analysis.

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

Ergon Energy's forecast therefore exceeds our top-down analysis based on both direct capex compared with the historical trend for fleet and equipment overall (Figure A.8), and motor vehicles totex per employee compared to its historical average (Figure A.9).

Accordingly, we have performed a detailed bottom-up assessment of Ergon Energy's fleet capex proposal, to identify areas where its forecasts do not reflect prudent and efficient costs, and to form a substitute estimate. To do this, we used Ergon Energy's fleet model and applied:

- least-cost crane borer service lives (-$11.0 million)
- historical service lives (-$5.2 million)
- additional least-cost emergency vehicle sourcing (-$2.4 million)
- private use of vehicles excluded from SCS capex (-$1.9 million)
- applying Ergon Energy's stated method of using historical averages to forecast tools and equipment capex (-$2.5 million).

This produced a substitute estimate for direct fleet, plant and equipment capex of $137.5 million, which is 14 percent lower than Ergon Energy's estimate. We discuss the reasons for each of these adjustments below and the approach we have adopted to forecast fleet volumes.

Crane Borer life extension

Ergon Energy's forecasts assume its crane borers are replaced after 10 years. However, Ergon Energy's analysis indicates substantial savings from extending life to 20 years.[185] Ergon Energy considers its crane borers "would not likely pass engineering assessment".[186] However, Ergon Energy has not provided evidence to support this. SA Power Networks stated that it achieves life extension in 97 per cent of cases and the age profile of crane borers owned by another network indicates high rates of life extension.[187]

We therefore consider it unlikely that all crane borers would fail inspection and a 10-year replacement cycle for all units is therefore not likely to reflect efficient and prudent costs. We also consider that Ergon Energy could perform inspections for a sample of crane borers to determine the percentage likely to pass.[188] Without this evidence, costs based on 97 per cent refurbishment (the rate achieved by SA Power Networks) is the most reasonable substitute estimate.

Consistent service lines and lead times

Ergon Energy's fleet model includes beginning of service dates and replacement quantities over 2020–25. We found inconsistencies between stated service lives and service lives implied by Ergon Energy's forecasts, so these forecasts exceed efficient costs. Our substitute applies stated service lives consistently.[189] This includes the lead time Ergon Energy identified for heavy fleet (6 months)[190] and forecasts of kilometres travelled.

Ergon Energy's fleet model also does not assume a refurbishment rate consistent with historical practice for EWPs and for vehicle loading cranes (VLCs), which likely reflects efficient costs and which our substitute estimate applies.[191]

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185 Ergon Energy estimates an NPV of $191,968 per unit. Ergon Energy, *Response information request 19 (part 2) – NPV analyses for smaller and already refurbished EWPs and Crane Borers*, 7 May 2019, p. 6.

186 Ergon Energy, *Fleet modelling response,* 3 July 2019, p. 5.

187 SA Power Networks, *Response to information request 23*, 1 May 2019, p.5. Our substitute also assumes refurbishment takes place at the refurbishment unit rate identified in Ergon Energy's fleet model, which excludes re-trucking costs. SA Power Networks does not include re-trucking costs in its forecasts, and Ergon Energy has not supplied evidence that re-trucking is likely to be necessary. Ergon Energy, *Fleet modelling response,* 3 July 2019, p. 5.

188 We asked Ergon Energy for evidence to support its service life assumption for crane borers in an information request and during a subsequent briefing. AER, *Information request 19 (part 2)*, 16 April 2019.

189 Ergon Energy, *Fleet asset management strategy,* January 2019, pp. 15–17.

190 Ergon Energy, *Fleet modelling response,* 3 July 2019, p. 2.

191 Ergon Energy identified 30 percent of VLCs as typically not suitable for refurbishment at 10 years. Ergon Energy, *Response to information request 44 – Replacement scheduling*, 28 June 2019, p. 4. For EWPs 14 metres or greater, Ergon Energy refurbished 48 percent of units historically, but its forecasts assume 31 percent refurbishment. Ergon Energy did not provide evidence to support this lower assumed refurbishment rate. Ergon Energy, *Response to information request 2,* 6 February 2019, pp. 14–15. All refurbishment rates are applied on a probabilistic basis (e.g. at 10 years, the refurbishment rate is multiplied by 48 per cent, and the replacement unit rate by 10 per cent; but at 15 years full replacement is assumed).

Additional vehicles for emergency response

Ergon Energy's forecast includes new vehicles to replace those it currently hires during emergency responses. However, Ergon Energy's NPV analysis shows its preferred option is the most costly one in NPV terms, and it states that this analysis overstates hiring costs.[192] Ergon Energy states that restoration times may be improved by purchasing the vehicles, but has not quantified the value of this to consumers.[193]

Ergon Energy therefore has not demonstrated that buying additional vehicles is efficient or prudent, compared with hiring. If Ergon Energy needed these vehicles currently, it would be able to fund the purchase given its fleet capex underspend over 2015–20.[194]

Private use

Ergon Energy permits significant private use of some vehicles. It does not adjust SCS capex for the percentage of private use, as only running costs are offset by employee contributions.[195] It is more appropriate that Ergon Energy fund the private use capex component of these vehicles through salaries. Our substitute estimate adjusts SCS capex downwards by the average percentage of private use for these vehicles over the current regulatory period.

Tools and equipment

Ergon Energy states that its tools and equipment forecast ($24.9 million) is "based on historical cost per employee".[196] However, Ergon Energy's forecasts $3,063 per employee, compared with an average spend of $2,750 per employee over 2015–18 actuals. Our substitute estimate applies Ergon Energy's stated method, which assumes no change in average spend per blue collar employee based on actuals for the current regulatory period ($22.4 million).

Fleet stock volumes

Similar to many networks, Ergon Energy's fleet volumes have been declining.[197] In response to our question about efficient fleet volumes, Ergon Energy stated that its proposal included a reduction of $4.8 million compared with a forecast based on

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192 Ergon Energy, *Response to information request 19 – Emergency vehicles*, 7 May 2019, p. 3. While the analysis calculates a slightly lower cost NPV for purchasing half the proposed number of vehicles compared with hiring, Ergon Energy stated that assumed hiring costs include costs for other purposes, which biases the result against hiring.

193 Ergon Energy, *Response to information request 19 – Emergency vehicles*, 7 May 2019, p. 3.

194 Ergon Energy identifies long lead times as a factor contributing to the decision to delay this investment, but this reinforces the case for investing in these vehicles over the current regulatory period if they are needed. Consistent with Ergon Energy's suggestion, we have allowed for a 6-month lead time for heavy fleet replacement in our forecasts. Ergon Energy, *Response to information request 19 – Emergency vehicles*, 7 May 2019, p. 3.

195 Ergon Energy, *Response to information request 44 – Private use tool of trade vehicles (PUToT)*, 28 June 2019, pp. 4–5.

196 Ergon Energy *Response to information request 19 – Plant and equipment bottom-up model*, 30 April 2019, pp. 2–6.

197 Ergon Energy, *Fleet asset management strategy,* January 2019, p. 7.

replacing all vehicles.[198] Our substitute estimate retains this reduction in percentage terms (3 per cent across 2020–25), which is likely to reflect a forecast of efficient fleet volume requirements.[199]

A.8 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 (CAM).

A.8.1 Draft decision

Ergon Energy has not sufficiently demonstrated that its capitalised overheads forecast of $686.5 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included an amount of $614.1 million in our substitute estimate of total capex. This is a reduction of $72.5 million (11 per cent). We are satisfied that our substitute estimate would form part of a total capex forecast that reasonably reflects the capex criteria. To arrive at our substitute estimate, we have applied a zero rate of change and adjusted the base year forecast to reflect our lower direct capex substitute estimate.

A.8.2 Ergon Energy's proposal

Ergon Energy proposed $686.5 million in capitalised overheads. Ergon Energy's capitalised overheads proposal is made up of three types of overheads:

- Network overheads – indirect costs incurred in activities such as network planning and project governance that are directly related to the network.
- Corporate overheads – related to finance, regulation, and people and culture.
- Non-network overheads – indirect costs incurred to operate and maintain vehicles, property occupancy, and information communication and technology costs.[200]

Ergon Energy's allocates 48 per cent of its total overhead costs to capex.

To forecast overheads, Ergon Energy applied a base step trend methodology that:

- adopted its 2018–19 capitalised overheads.

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[198] Figure is in $2017. Ergon Energy, *Response to information request 19 – Fleet volumes,* 30 April 2019, p. 2. See also Ergon Energy, *Response to information request 2 – Appendix B Ergon Energy strategic fleet initiatives,* 25 February 2019, slide 3, which identifies that this reduction is intended to reduce volumes.

[199] After reviewing our fleet model, Ergon Energy argued that the savings it identified under this category should not be additional to our bottom-up reductions. However, as Ergon Energy originally identified these savings as a volume-based reduction, and our substitute assumes zero volume growth, excluding these volumetric savings as originally proposed would not form part of an efficient fleet capex forecast. Ergon Energy, *Fleet modelling response,* 3 July 2019, p. 10.

[200] Ergon Energy, *Ergon Energy regulatory proposal 2020–25,* January 2019, p. 79.

- removed capitalised overheads base year change fund and redundancies that are not part of the capitalised overheads. It also removed expected savings to be delivered in 2019–20.
- applied the output growth and price growth measures used in its opex forecasts. It then applied a targeted 10 per cent savings target for overheads over the 2020–25 regulatory control period.[201]

Ergon Energy's regulatory proposal document presented network overheads and corporate overheads as part of its capitalised overheads proposal. It included non-network overheads in the relevant non-network capex categories.[202] However, these non-network overheads are treated in the same way as other overheads in Ergon Energy's capex model.

A.8.3 Reasons for draft decision

We have assessed Ergon Energy's base and trend methodology and compared it with historical overheads. We have based our position on a holistic approach taking into account both the trend in capex overheads and total overheads.

For trend analysis, we have focussed on network and corporate overheads. This is because non-network overheads are a new post-merger overhead category and historical data is not available.[203] Further, cost allocation methodology (CAM) changes and other adjustment means that there is limited data on a like-for-like basis.

We have also considered the interaction between Ergon Energy and Energex, as Ergon Energy reported that the productivity component reflects a 10 per cent reduction in EQ overheads over the 2020–25 regulatory control period.[204]

Assessment of base and trend forecasting methodology

We have assessed Ergon Energy's base and trend methodology. Ergon Energy has not justified its base 2018–19 overheads. Although Ergon Energy's overheads have materially decreased as a result of CAM changes, on a like-for-like basis, Ergon Energy's network and corporate overheads was $65.7 million and $56.7 million in 2016–17 and 2017–18, respectively. These overheads account for $70.4 million of Ergon Energy's $129.5 million base year.

As Ergon Energy's non-network overheads is a new type of overhead, historical data is not available. These overheads are also likely to have increased as Ergon Energy has applied the same forecasting methodology to these overheads. Therefore, our observations on the subset of overheads is applicable to total capex overheads. We have also assessed Ergon Energy's proposed rate of change for capitalised overheads in Table A.7 below.

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201 Ergon Energy, *Ergon Energy regulatory proposal 2020–25,* January 2019, p. 79.

202 Ergon Energy, *Ergon Energy regulatory proposal 2020–25,* January 2019, p. 80.

203 Ergon Energy, *Response to information request 20,* May 2019, p. 3.

204 Ergon Energy, *Ergon Energy regulatory proposal 2020–25,* January 2019, p. 79.

Table A.7 – Forecast overhead rate of change by rate of change component (per cent)

	2020–21	2021–22	2022–23	2023–24	2024–25
Output	1.13	1.13	1.07	0.92	0.92
Price	-0.19	0.05	0.28	0.31	0.31
Productivity	0.29	0.29	0.29	0.29	0.29
Overall	0.65	0.89	1.06	0.94	0.94
Actual overall	0.65	1.55	2.63	3.59	4.57
Opex productivity	2.58	2.58	2.58	2.58	2.58

Source: Ergon Energy's capex model and AER analysis.

We have identified a calculation error in Ergon Energy's capex model, which resulted in an exponentially increasing annual rate of change. For example, Ergon Energy's 2024–25 capitalised overheads is 4.6 per cent higher than its 2023–24 overheads, even though its forecasting methodology indicates it should be 0.9 per cent higher. Adjusting for this error reduces Ergon Energy's forecast overheads from $686.5 million to $664.4 million, a reduction of $22.1 million.[205]

Ergon Energy's forecast rate of change is not in line with Ergon Energy's actual overheads, which has steadily declined since 2014–15 where corporate and network overheads at the total SCS and capex level was $611.0 million and $122.9 million, respectively. This reduced to $470.7 million and $56.7 million in 2017–18, respectively. We do not consider Ergon Energy's rate of change, which is increasing over time, is reasonable given the declining overheads trend to date. Further, Ergon Energy has forecast a 2.6 per cent annual decrease in overheads allocated to opex.

In response to our information request, Ergon Energy did not demonstrate why opex and capex had materially different rates of change. The difference is too significant to be driven by the CAM. For example, the capex proportion of network and corporate overheads relative to total SCS overheads was 23.3 per cent in 2017–18 and forecast to increase to 33.7 per cent by 2024–25. Meanwhile, the opex share decreases from 76.7 per cent to 66.3 per cent. This indicates that there may be substitution of overheads from opex to capex in excess of the CAM.

As Ergon Energy's base overheads are higher than historical on a like-for-like basis and the rate of change is positive even though recent years there has been a decline in overheads, we do not consider Ergon Energy's overheads forecast is reasonable.

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[205] We have applied the same adjustment to Energex, which results in a $37.5 million increase to Energex's overheads.

Our substitute estimate

There is a relationship between the quantity of direct capex and overheads. As our direct capex substitute estimate is lower than Ergon Energy's capex proposal, we would expect Ergon Energy to require less overheads for this lower volume of work. It follows that we would expect some reduction in the size of capitalised overheads.

We accept that some capitalised overheads are fixed in the short term and so are not correlated to the size of the expenditure program. In response to our information request for the historical relationship between direct expenditure and overheads, Ergon Energy noted that this data was not available. Ergon Energy considered that if available it would be consistent with our previous determination of adopting a 75 per cent fixed and 25 variable ratio.[206]

In the absence of alternative information, we have adopted this ratio. As our direct capex substitute estimate is 21.4 per cent lower than Ergon Energy's proposal, this results in a 5.3 per cent reduction in Ergon Energy's base capitalised overheads.

We have also applied a zero rate of change. Ergon Energy's total overheads are decreasing over the 2020–25 regulatory control period and Ergon Energy's actual capitalised overheads have been decreasing over time. However, we recognise that the allocation of overheads to capex and opex is relative. Given that Ergon Energy has forecast decreases in its opex it means that, based on the CAM, Ergon Energy should allocate more overheads to capex. Taking these two drivers into account, we are satisfied that no increase or decrease over the forecast period is reasonable.

[206] Ergon Energy, *Response to information request 20,* May 2019, p. 2.

B Engagement process and data discrepancies

B.1 Engagement with Ergon Energy

Initial proposal

Ergon Energy submitted its proposal on 31 January 2019. The proposal included a capex attachment, which provided a high-level view of Ergon Energy's capex forecast. Throughout our assessment of Ergon Energy's initial proposal, we requested further information via multiple information requests.

We sent 37 information requests relating to Ergon Energy's distribution capex forecast. These questions aimed to test our understanding of the revised material provided and to clarify capex-related issues, particularly data reporting and consistency issues that are outlined in more detail in section B.2 below.

Engagement

We engaged with CCP14, Energy Consumers Australia and the Queensland Electrical Safety Office during the review process to understand and test their views on Ergon Energy's capex proposal. We had regard to their views and their public submissions, when provided, along with all the other submissions that we received on Ergon Energy's capex proposal. Below we outline the interactions we have had with Ergon Energy in the lead up to the draft decision.

Pre-proposal stage

- We attended Ergon Energy's capex 'deep dive' in November 2018, which allowed us to gain a greater understanding of its capex proposal. We raised concerns with Ergon Energy that its forecasting methodology did not satisfactorily quantify risks or benefits.
- We also presented our modelling approach, including preliminary modelling results, during this capex deep dive session.
- We had a further repex modelling discussion with Ergon Energy in December 2018, where we explained our repex modelling technique and the rationale underpinning our latest decisions.

During the review period

We engaged with Ergon Energy on an ongoing basis during the review period. The purpose of our engagement was to seek further information on its capex proposal and to provide timely feedback to Ergon Energy about our concerns. We outlined what information was required from Ergon Energy to justify its forecast.

On 16 April 2019, the General Manager of Distribution Networks emailed Ergon Energy to outline our preliminary views on its capex proposal. The email highlighted several concerns that we had, including inadequate cost-benefit analysis, lack of risk quantification, insufficient or lack of options analysis, and data reconciliation issues.

We met with Ergon Energy staff during an on-site meeting with EMCa on 16 and 17 May 2019. This meeting primarily related to Ergon Energy's repex and ICT capex forecasts. On 23 May 2019, we also met with Ergon Energy staff to discuss differences in repex modelling results and approaches.

On 4 June 2019, the capex team met with Ergon Energy staff to discuss our current position and existing information gaps in detail. We went through each capex driver, focusing on the areas we had concerns about, and invited Ergon Energy to provide further information or to contact us directly to talk through any issues.

Following the meeting on 4 June 2019, Ergon Energy provided additional information to address our concerns. It also requested follow-up meetings to further clarify any outstanding issues on specific capex drivers on 18 June 2019, 27 June 2019, 31 July 2019 and 7 August 2019.

On 12 June 2019, we met with Ergon Energy to discuss our approach to wooden pole modelling within the context of repex model. In addition, we met with Ergon Energy to discuss a data discrepancy issue (information request 45), which is explained in detail in section B.2. We met with Ergon Energy to discuss its progress in reconciling this data discrepancy issue on 26 July 2019.

B.2 Recast historical data discrepancies

During our assessment of Ergon Energy's recast proposal, we discovered several data reporting inconsistencies between Ergon Energy's initial data and subsequent recast data.[207] In information request 43, we highlighted reconciliation issues between Ergon Energy's back cast CA RIN data and submitted roll-forward model (RFM).[208] In response, Ergon Energy indicated that its recast CA RIN data would not reconcile with the data in the RFM because the two data sources were not comparable. Ergon Energy stated:

> The RFM represents actual expenditure reported in accordance with the current approved Cost Allocation Method (CAM) and Classification of Services (CoS) for the 2015–20 regulatory control period. The recast CA RIN has taken the data from our annual RIN submissions and recast it using the CAM and CoS that will apply in the next regulatory control period to provide a basis of comparison for our forecasts on a like-for-like basis.[209]

We are satisfied that Ergon Energy's response explains why the two capex data sources did not reconcile. However, in information request 45, we highlighted that we were still unable to reconcile the total standard control service (SCS) and alternative

[207] Ergon Energy, *2020–25 recast category analysis RIN template,* 27 February 2019.

[208] AER, *Ergon Energy information request 43,* 7 June 2019.

[209] Ergon Energy, *Response to information request 43*, 11 June 2019, p. 1.

control service (ACS) total expenditure data between the previous CA RINs and the new back cast CA RIN data.[210]

We analysed Ergon Energy's recast data and expected the two data sources to reconcile, as we rely on this underlying granular expenditure data to assess a distributor's capex forecast, including capex category analysis and repex modelling. Table B.1 and Table B.2 below outline a summary of the two data sources, and Table B.3 outlines the differences.

Table B.1 – Total SCS and ACS expenditure under previous CAM and CoS ($, nominal)

	2014-15	2015-16	2016-17	2017-18
2.1.1 - STANDARD CONTROL SERVICES CAPEX	$839,271,136	$610,834,613	$517,766,007	$514,035,408
2.1.2 - STANDARD CONTROL SERVICES OPEX	$501,176,002	$498,916,765	$354,793,340	$386,448,763
2.1.3 - ALTERNATIVE CONTROL SERVICES CAPEX	$26,343,979	$40,107,205	$66,940,539	$70,006,254
2.1.4 - ALTERNATIVE CONTROL SERVICES OPEX	$45,515,964	$65,956,127	$84,297,622	$77,260,878
TOTAL	$1,412,307,081	$1,215,814,710	$1,023,797,509	$1,047,751,302

Source: Ergon Energy's previous CA RIN data and AER analysis.

Table B.2 – Total SCS and ACS expenditure under new CAM and CoS ($, nominal)

	2014-15	2015-16	2016-17	2017-18
2.1.1 - STANDARD CONTROL SERVICES CAPEX	$740,327,694	$568,966,952	$430,957,009	$427,304,892
2.1.2 - STANDARD CONTROL SERVICES OPEX	$543,967,455	$522,548,623	$367,077,848	$393,094,289
2.1.3 - ALTERNATIVE CONTROL SERVICES CAPEX	$27,326,271	$40,919,126	$55,901,635	$65,462,112
2.1.4 - ALTERNATIVE CONTROL SERVICES OPEX	$47,235,560	$65,797,739	$70,221,305	$67,762,822
TOTAL	$1,358,856,981	$1,198,232,439	$924,157,796	$953,624,115

Source: Ergon Energy's recast CA RIN data and AER analysis.

Table B.3 – Differences between tables Table B.1 and Table B.2 ($, nominal)

	2014-15	2015-16	2016-17	2017-18
2.1.1 - STANDARD CONTROL SERVICES CAPEX	-$98,943,442	-$41,867,662	-$86,808,998	-$86,730,516
2.1.2 - STANDARD CONTROL SERVICES OPEX	$42,791,453	$23,631,858	$12,284,508	$6,645,527
2.1.3 - ALTERNATIVE CONTROL SERVICES CAPEX	$982,292	$811,921	-$11,038,904	-$4,544,142
2.1.4 - ALTERNATIVE CONTROL SERVICES OPEX	$1,719,596	-$158,388	-$14,076,318	-$9,498,056
TOTAL	-$53,450,101	-$17,582,271	-$99,639,713	-$94,127,187

Source: AER analysis.

Table B.3 highlights that under Ergon Energy's new CAM and CoS, total SCS and ACS expenditure over the last four years is $264.8 million lower than under Ergon Energy's previous CAM and CoS. We sought to understand these discrepancies in information

[210] AER, *Ergon Energy information request 45,* 12 June 2019.

request 45.[211] Ergon Energy's initial response indicated that it was "unable to provide a quantified response".[212] Ergon Energy also stated:

> Quantification is not possible due to the nature of the reported information and the method, which was approved by the AER, applied to the materiality assessment for back casting purposes. While isolation of the impact of some of the proposed changes can be identified at a high level, the interrelationship with other adjustments are unknown and any value that is provided without this knowledge could be potentially misleading. It would not be appropriate to provide values which are not supported by the available data, however, an explanation of the changes can be provided and this outlined below.[213]

Ergon Energy's initial response also qualitatively discussed several factors that contributed to the data discrepancies, including removal of fleet depreciation, the dissolution of SPARQ, and changes to non-network operating costs and corporate overheads. However, as noted above, Ergon Energy was unable to quantify any of these changes.

Following this response, we met with Ergon Energy to reiterate our concerns with the recast data and the lack of clarity regarding the reconciliation issues. Following this discussion, Ergon Energy agreed to try to quantify the data differences for 2016–17, and to assist, we provided the working spreadsheet that underpinned information request 45.[214] Ergon Energy's second response provided more detail, including quantified differences for 2016–17 and further explanation.[215] Figure B.1 outlines this information.

Figure B.1 – Ergon Energy's reasons for 2016–17 data discrepancies ($ nominal)

	2016-17
Sparq ICT treatment - diff betw reported in 2.10 and backcast for ICT in 2.6	10,159,765
Property treatment - diff betw reported in 2.10 and backcast for Property in 2.6	3,826,975
OH transferring to EGX due to CAM change (3 factor method applied to corporate costs)	22,973,552
Fleet costs and depn removed from directs and SCS portion of operating costs reported in 2.6 NNW	31,406,769
sale of inventory (previously NR and not reported)	- 7,630,624
ACS opex fee and quoted reported initially but not in backcast numbers	36,924,110
	97,660,547

Figure B.1 and additional meetings with Ergon Energy helped to explain that its back cast ACS data was likely to be understated due to the different treatments outlined above. Ergon Energy also provided a similar reconciliation response for 2015–16[216], but it was not able to provide equivalent responses for 2014–15 and 2015–16.

211 AER, *Ergon Energy information request 45,* 12 June 2019.

212 Ergon Energy, *Response to information request 43*, 11 June 2019, p. 3.

213 Ergon Energy, *Response to information request 43*, 11 June 2019, p. 3.

214 AER, *Information request 45 follow-up – Ergon Energy expenditure calculations,* 4 July 2019.

215 Ergon Energy, *Information request 45 follow-up,* 23 July 2019.

216 Ergon Energy, *Information request 45 follow-up,* 9 August 2019.

For this draft decision, we have used Ergon Energy's recast CA RIN data to undertake our capex assessment, as this data allows for a like-for-like comparison with its forecast capex data. However, we encourage Ergon Energy to provide these equivalent responses for 2014–15 and 2015–16, or resubmit its recast CA RIN data in its revised proposal so that it more closely reconciles with its previous CA RIN data.

We will have regard to all of Ergon Energy's revised proposal information and if Ergon Energy cannot adequately explain the remaining data discrepancies, we may rely on Ergon Energy's previous CA RIN in the final decision.

C Forecast demand

Maximum demand forecasts are fundamental to a distributor's forecast capex and opex and to our assessment. We must determine whether the capex and opex forecasts reasonably reflect a realistic expectation of demand forecasts and cost inputs required to achieve the capex objectives.[217] Accurate demand forecasts are therefore important inputs to ensure efficient network investment.

C.1 Draft decision

Ergon Energy's demand forecast reflects a realistic expectation of demand over the 2020–25 regulatory control period. Ergon Energy's forecast peak demand growth of 0.3 per cent per annum is within the range of AEMO's forecast of 0.3 to 0.4 per cent per annum over the 2020–25 period.[218] However, we have identified some issues in Ergon Energy's modelling and forecasting approach that it may wish to consider for future forecasts.

C.2 Ergon Energy's proposal

Ergon Energy forecast system peak demand to grow at 0.3 per cent per annum in the 2020–25 period.[219] It is relatively flat compared with recent history, which has seen record levels of peak demand in the summers of 2017 and 2018 (2637MW and 2597MW, respectively). The temperature corrected peak demand at 50 per cent probability of exceedance (POE) is forecast to grow from 2550MW in 2018–19 to 2601MW in 2022–23, before a decline to 2574MW in 2024–25.[220] Figure C.1 shows Ergon Energy's historical coincident summer peak demand actuals and forecast.

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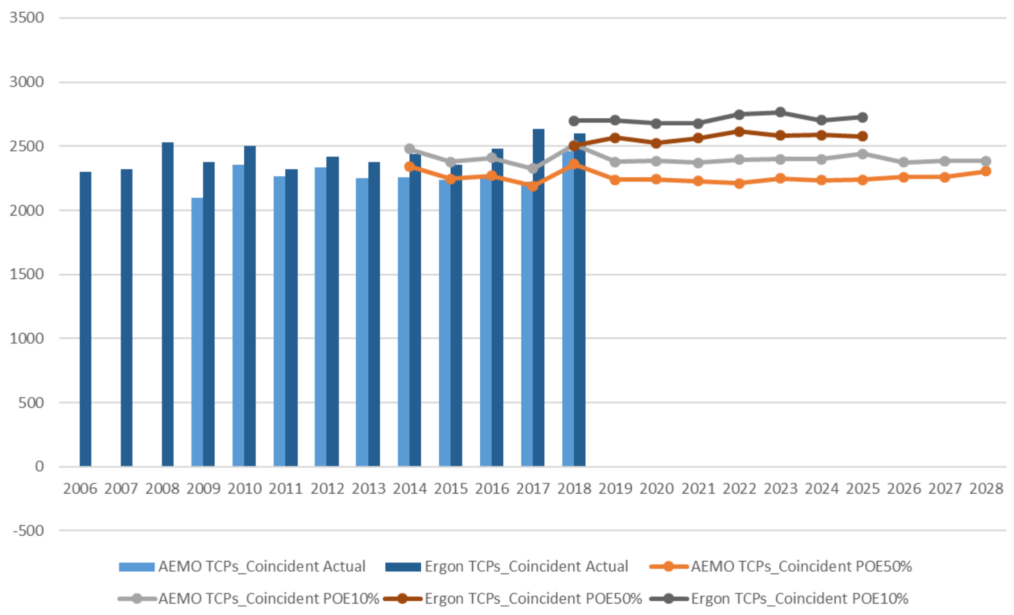
217 NER, cll. 6.5.6(c)(3), 6.5.7(c)(1)(iii).

218 AEMO's 2018 Electricity Statement of Opportunities forecast for Ergon Energy is 0.3 percent per annum at POE50% (coincident and non-coincident), and 0.4 per cent per annum at POE10% (coincident and non-coincident).

219 Ergon Energy, *Ergon Energy regulatory proposal 2020–25*, January 2019, p. 35.

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

Figure C.1 – Ergon Energy and AEMO coincident summer peak demand actuals forecasts (2006–2028) (MW)



Source: Ergon Energy's RIN responses, AEMO forecasting data panel and AER analysis.

C.3 Reasons for draft decision

To assess Ergon Energy's peak demand forecast, we have had regard to:

- AEMO's transmission connection point forecasts, which we have used as a point of comparison
- Ergon Energy's peak forecasting methodology.

Comparison between AEMO forecast and Ergon Energy's forecast

We have compared Ergon Energy's forecast with AEMO's maximum demand forecast from its 2018 Electricity Statement of Opportunities (ESOO).[221] Figure C.1 also shows AEMO's forecast of summer peak demand for the Ergon Energy network region. AEMO's coincident system peak demand for the Ergon Energy network is 2226MW and 2461MW in 2016–17 and 2017–18. The weather-corrected peak demand (at POE50%) is 2,361MW in 2017–18. AEMO forecasts peak demand to fall to 2237MW in 2018–19 and remain relatively flat up to 2024–25, with an average growth rate of 0.3 to 0.4 per cent per annum depending on the measure.[222]

221 Data sourced from AEMO, Forecasting *data portal*, available at: http://forecasting.aemo.com.au/.

222 AEMO's 2018 Electricity Statement of Opportunities peak demand forecast for Ergon Energy is 0.3 percent per annum at POE50% (coincident and non-coincident), and 0.4 per cent per annum at POE10% (coincident and non-coincident).

While both forecasts measure coincident system peak demand for the Ergon Energy network, they are measured differently and the forecasts are not directly comparable.[223] However, we consider that they are likely to be influenced by the same set of demand drivers and would expect the forecasts of similar annual growth rates. We found that Ergon Energy's forecast of 0.3 per cent annual peak demand growth is within the range of AEMO's forecasts (between 0.3 and 0.4 per cent per annum).

Review of Ergon Energy's peak demand forecasting methodology

Ergon Energy's system peak demand forecasts are produced using a top-down econometric modelling approach. It engaged ACIL Allen to review its forecasting methodology with respect to system maximum demand and energy delivered.[224]

Ergon Energy's overall forecasting approach is reasonable. The modelling approach accounts for a set of key drivers of electricity demand, similar but notably more limited, to those considered by AEMO. The resulting demand forecasts seem to trend broadly in line with the AEMO forecasts with upward revision for the 2019 ESOO.

Although we consider that Ergon Energy's forecasting approach is reasonable, we identified some issues with its modelling and forecasting approaches that could be reviewed to improve future forecasts, including:

- model and variable specification
- post-modelling adjustments for DERs and block loads.

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223 The Ergon Energy measure is the aggregated demand at the transmission connection point level (on the distribution side) at the time of the Ergon Energy network peak. The AEMO measure is the aggregated demand at Ergon Energy's transmission connection points with Powerlink, at the time of the Queensland-wide Energex/Ergon Energy system peak. The Ergon Energy approach could lead to a higher forecast because it would not need to account for constraints outside its own network as may be the case with AEMO's approach. The Ergon Energy approach can also produce a lower forecast as it is measured on the distribution side and is therefore subject to distribution energy losses.

224 ACIL Allen Consulting, *Review of Energex's and Ergon Energy's approach to system maximum demand and energy delivered,* May 2018.

D Ex-post prudency and efficiency review

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.[225] 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.[226]

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. 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:

- The distributor has spent more than its capex allowance (the 'overspending' requirement).
- 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).
- Where the distributor's capex includes expenditure that should have been treated as opex (the 'capitalisation' requirement).[227]

D.1 Draft decision

We are satisfied that Ergon Energy's capital expenditure in the 2015–16, 2016–17 and 2017–18 regulatory years should be rolled into the RAB.

D.2 Reasons for draft decision

We have reviewed Ergon Energy's capex performance for the 2015–16, 2016–17 and 2017–18 regulatory years. This assessment has considered Ergon Energy's actual capex relative to the regulatory allowance provided and the incentive properties of the regulatory regime for a distributor to minimise costs. Ergon Energy's 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.[228] We recognise that there is no perfect benchmarking model, but our benchmarking models are robust measures of economic

225 NER, cl. 6.12.2(b).

226 NER, cl. 6.4A(a).

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

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

efficiency and we can use this measure to assess and compare a distributor's efficiency.

The results from our most recent benchmarking report highlight that Ergon Energy increased to the sixth most efficient distributor out of the thirteen NEM distributors with a multilateral total factor productivity (MTFP) score of 1.106 for 2017. 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.

Overall, our analysis has revealed that the 'overspending', 'margin' and 'capitalisation' requirements are not satisfied for Ergon Energy.[229] Therefore, we are satisfied that the entirety of Ergon Energy's capital expenditure in the 2015–16, 2016–17 and 2017–18 regulatory years should be rolled into the RAB.

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