Jemena Electricity Networks (Vic) Ltd

2021-26 Electricity Distribution Price Review - Revised Proposal

Attachment 04-01

Response to the AER's draft decision - Capital expenditure

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Glossary

ES Act	Electricity Safety Act 1998
ES Regulations	Electricity Safety (Bushfire Mitigation) Regulations 2013
Initial proposal	JEN's initial regulatory proposal to the AER submitted on 31 January 2020 for the setting of regulated prices for the next regulatory period
Jemena	Jemena is the corporate group entity that owns Jemena Electricity Networks (Vic) Ltd.
Next regulatory period	The regulatory period commencing 1 July 2021 and concluding 30 June 2026
Required capacity	The prescribed performance standards of polyphase electric lines for bushfire mitigation purposes, as defined in the Electricity Safety (Bushfire Mitigation Duties) Regulations 2017

Abbreviations

ACIF	Australian Construction Industry Forum
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
CCP17	Consumer Challenge Panel - Sub-panel 17
COO	Coolaroo zone substation
CPI	Consumer Price Inflation
CRM	Customer Relationship Management
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DELWP	Department of Energy, Land, Water and Planning
ERP	Enterprise Resource Platform
ESC	Essential Services Commission of Victoria
ESV	Energy Safe Victoria
FY	Financial Year[1]
GVE	Greenvale zone substation
HBRA	Hazardous Bushfire Risk Area
HIA	Housing Industry Association
HV	High Voltage
ICT	Information & Communications Technology
IS-U	Industry Specific – Utility
JEN	Jemena Electricity Networks (Vic) Ltd
JGN	Jemena Gas Networks (NSW) Ltd
KLO	Kalkallo Zone Substation
LBRA	Low Bushfire Risk Area
LV	Low Voltage
MEC	Major Electricity Company
NSP	Network Service Provider
REFCL	Rapid Earth Fault Current Limiter
WPI	Wage Price Inflation

[1] When expressing the financial year, we follow the initials with a two year digit code. The two digits represent the latest year that straddled the annual period. For example, the financial year 1 July 2021 to 30 Jun 2022 is represented as FY22.

Overview

This document sets out our response to the Australian Energy Regulator's (**AER**) draft decision on Jemena Electricity Networks (Vic) Ltd's (**JEN**) forecast capital expenditure for Standard Control Services during the 2021-26 regulatory period (**next regulatory period**). It also sets out our revised capital expenditure forecast.

We welcome the AER's draft decision on our capital expenditure. The AER was generally satisfied that our forecast reflected the capital expenditure criteria.[2] The AER's top-down and bottom-up category analysis taken together found our proposed capital expenditure in aggregate to be prudent and efficient, subject to adjustments to connections and cost escalation due to the unforeseen impacts of COVID-19 and an adjustment to our Rapid Earth Fault Current Limiter (**REFCL**) program.[3]

We also welcome the acknowledgement in the draft decision of the preferences and concerns of our customers and stakeholders in relation to our capital expenditure.[4] This reinforces the central role our customers' feedback and preferences played in the development of our capital expenditure forecast—which we designed to respond to four objectives, shown below.

Objectives for our capital expenditure forecast

- Meet customers' expectations that we should maintain our current levels of network reliability (including the frequency and duration of outages) at the most efficient cost over the long term
- Manage safety, environmental, physical security and cybersecurity risks to as low as practicable and comply with all applicable regulatory obligations at the most efficient cost over the long term
- Connect new customers to our network and meet the changing energy needs of existing customers, ensuring we can meet or manage expected demand for all customers at the least cost over the long term
- Efficiently minimise any constraints on grid exports from distributed energy resources (**DER**) to the extent possible.

Our revised forecast

Our revised capital expenditure forecast substantially adopts the draft decision's amounts in most areas, while also incorporating new information for a small number of specific matters. Our forecast capital expenditure for the next regulatory period is $626M net ($769M gross), which represents a 3.9 per cent increase from the draft decision and a 0.2 per cent decrease from our 2021-26 initial regulatory proposal (**initial proposal**). Key changes between our initial proposal, the draft decision and our revised proposal capital expenditure forecasts are shown in Figure OV–1.

2 AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-6.

3 AER, *Draft decision: Jemena Distribution Determination 2021 to 2026, Overview*, September 2020, p. 8.

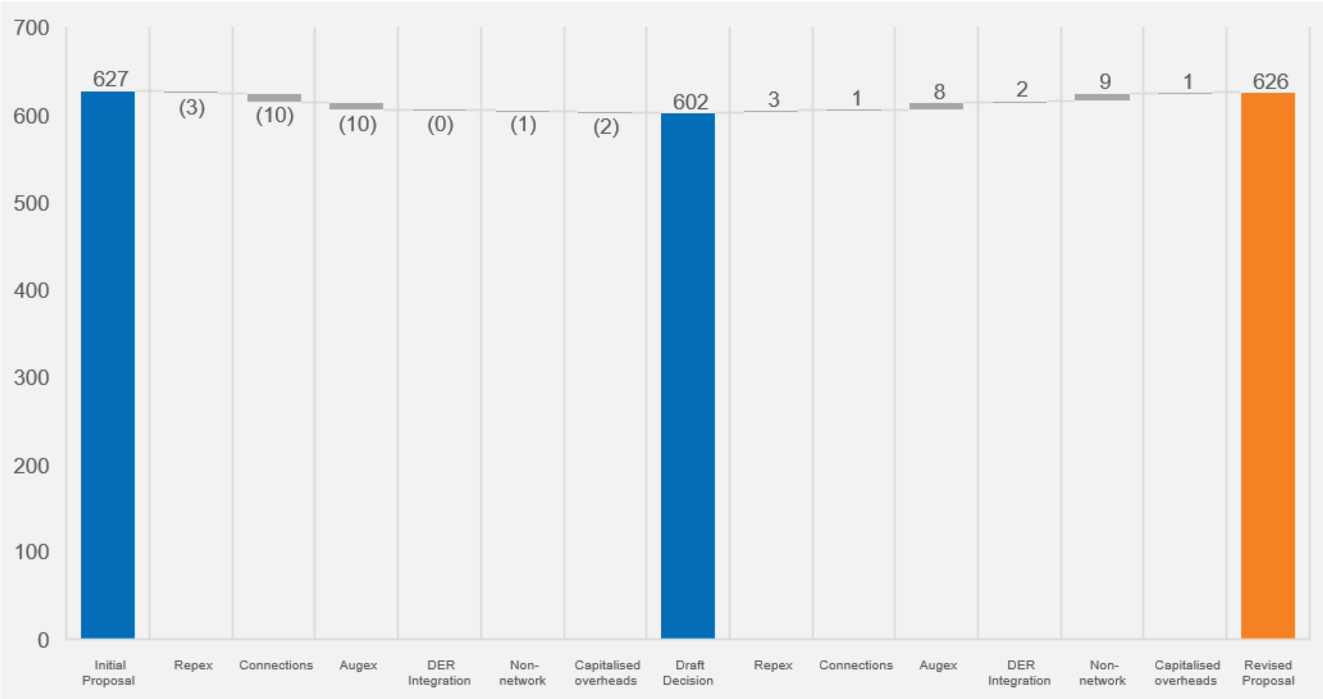
4 AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, pp. 5-10 – 5-11 and AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-24.

What our revised proposal means for our customers

Our revised proposal's capital expenditure forecast reflects the prudent and efficient expenditure we require to deliver the services and outcomes that our customers have told us they expect, both now and over the long-term. Specifically, this includes:

- allowing us to maintain our current network service levels at an efficient cost over long term
- efficiently addressing and minimising DER constraints in line with the clear expectations of our customers
- responding to customers' affordability concerns by reflecting lower costs of complying with mandatory bushfire mitigation obligations in the Coolaroo area under our revised approach.

Figure OV–1: How our revised proposal capital expenditure compares (5 years, $ June 2021, millions)



The draft decision raised two main issues in relation to our capital expenditure forecast—the potential effects of COVID-19 and changes to our REFCL program—both of which we have addressed in our revised proposal.

Our initial proposal was prepared before COVID-19 emerged and accordingly did not factor in its impacts. We have since considered the potential effects of COVID-19 on our connections and demand-driven augmentation capital expenditure. We found that, aside from the reduction to connections expenditure reflected in the draft decision, COVID-19 is unlikely to lead to any further material changes in aggregate to our forecast connections or augmentation expenditure. Our revised proposal forecast therefore accepts the draft decision's forecasts for these categories.

Additionally, we have updated our capital expenditure forecast to:

- reflect the outcomes of an exemption we pursued in relation to bushfire mitigation (including REFCL) obligations at Coolaroo zone substation, allowing for a lower cost solution for this project.

- incorporate externally-driven changes to our approach to complying with bushfire mitigation obligations for Kalkallo zone substation
- make relatively minor updates to our non-network and DER integration forecasts to reflect matters noted in the draft decision
- reflect the AER's standard approach to real cost escalation, consistent with our operating expenditure forecast.[5]

The key decision items outlined in the AER's draft decision and our responses to each of these are summarised in Table OV–1, with Table OV–2 and Table OV–3 presenting our revised capital expenditure forecast. The remainder of this document details our responses to the draft decision and our revised capital expenditure forecasts in relation to the six capital expenditure categories set out in the draft decision. Unless otherwise stated, dollar figures throughout this document are expressed in real June 2021 dollars, exclusive of overheads.

Table OV–1: Key elements of the AER's draft decision

Issue	AER positions	JEN response
Replacement expenditure	Accept initial proposal	Accept draft decision
Connections expenditure	Accept initial proposal, subject to negative adjustment for impact of COVID-19	Accept draft decision's adjustment methodology with data to be updated; no further material downward impact on net expenditure
Augmentation expenditure	Traditional augmentation expenditure – accept initial proposal, with COVID-19 impacts to be reconsidered	Traditional augmentation expenditure – accept draft decision, aggregate impacts of COVID-19 on our forecast are not material
	REFCL augmentation expenditure – information to be updated	REFCL augmentation expenditure – new information and forecast provided
DER integration expenditure	Accept initial proposal, noting stakeholder concerns around distributed energy resources valuation	We have considered the impacts of a wide range of DER benefit values, and confirm our program is in customers' long-term interests. We have accepted the draft decision forecast, with two minor additions to reflect some of the activities previously included in our operating expenditure step change
Non-network expenditure	Accept initial proposal, noting one non-network IT project was excluded from our initial proposal forecast	Accept draft decision, along with addition of one previously omitted non-network IT project
Capitalised overheads	Accept JEN's methodology, forecast updated for changes in direct capital expenditure	Maintain methodology, forecast updated for changes in direct capital expenditure
Real cost escalation	Modelling adjustments to real cost escalation to reflect Deloitte forecasts, consistent with the AER's operating expenditure draft decision. Final decision to adopt AER's standard approach (average of two consultant forecasts)	Updated to reflect AER's standard approach by including average of Deloitte and BIS Oxford Economics forecasts, consistent with our approach used in our operating expenditure forecast

5 Our updates to real price escalation are discussed further in section 3.1.1.2 of Attachment 05-01 to our revised proposal.

Table OV–2: How our revised proposal capital expenditure forecast compares (5 years, $ June 2021, millions)

Capital expenditure category	Initial Proposal	Draft Decision	Revised Proposal
Replacement	210.9	208.4	211.1
Connections	218.0	198.0	199.1
Augmentation	133.7	124.0	131.8
DER integration	28.5	28.2	30.4
Non-network	98.2	97.7	106.6
Capitalised overheads	91.2	89.0	90.1
Gross capital expenditure	**780.5**	**745.4**	**769.1**
Capital contributions	(153.0)	(142.6)	(142.6)
Asset disposals	(0.5)	(0.5)	(0.5)
Net capital expenditure	**627.1**	**602.3**	**625.9**

Table OV–3: Our annual revised proposal capital expenditure forecast by category ($ June 2021, millions)[6]

Capital expenditure category	FY22	FY23	FY24	FY25	FY26	Total
Replacement	46.1	41.1	40.3	41.1	42.5	**211.1**
Connections	26.9	41.6	43.9	45.3	41.4	**199.1**
Augmentation	35.4	49.6	24.8	15.0	6.9	**131.8**
DER integration	5.6	4.0	8.5	7.1	5.2	**30.4**
Non-network	34.0	22.8	19.6	19.7	10.4	**106.6**
Capitalised overheads	17.8	19.1	18.1	17.8	17.3	**90.1**
Gross capital expenditure	**165.8**	**178.2**	**155.2**	**146.0**	**123.9**	**769.1**
Capital contributions	(22.0)	(29.8)	(30.7)	(30.6)	(29.5)	**(142.6)**
Asset disposals	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	**(0.5)**
Net capital expenditure	**143.6**	**148.4**	**124.4**	**115.3**	**94.3**	**625.9**

6 Equity raising costs are not shown in this table. Equity raising costs are transaction costs that we incur when we raise equity. JEN recognises equity raising costs as capital expenditure within the Post Tax Revenue Model (**PTRM**) and amortises these costs over the life of the assets that they are used to fund. The AER has applied a benchmark approach in its recent regulatory decisions for determining costs for raising equity through dividend reinvestment plans and seasoned equity offerings. These costs have been forecast using the AER's approach contained in the PTRM included in our revised proposal.

Supporting material

Additional information provided in support of JEN's revised proposal capital expenditure forecast is outlined in Table OV–4.

Table OV–4: Additional documents supporting this submission

Document reference	Document title
Attachment 04-01	Response to the AER's Draft Decision - Capital Expenditure
Attachment 04-02	Future Grid Investment Proposal (Addendum)
Attachment 04-03	Network Development Strategy – Comply with Bushfire Mitigation Obligations at Coolaroo Zone Substation
Attachment 04-04	Coolaroo and Greenvale Bushfire Mitigation Obligation Compliance Works Cost Estimate
Attachment 04-05	Network Development Strategy – Comply with Bushfire Mitigation Obligations on JEN KLO 22kV Feeders
Attachment 04-06	Kalkallo Bushfire Mitigation Obligation Compliance Works Cost Estimate
Attachment 04-01M	Capital Expenditure Model

1. Replacement expenditure

We need to replace existing parts of the network which have reached the end of their economic lives with their modern equivalents (or a lesser capacity asset if possible) so that we can maintain our current levels of network services, consistent with our customers' expectations. We developed our replacement expenditure forecast around the objectives set out below, as set out in our initial proposal.[7]

> Meet customers' expectations that we should maintain our current levels of network reliability (including the frequency and duration of network outages) at the most efficient cost over the long term.
>
> Manage safety, environmental, physical security and cybersecurity risks to as low as practicable and comply with all applicable regulatory obligations at the most efficient cost over the long term.

JEN welcomes the AER's finding that our forecast replacement expenditure reasonably reflects the capital expenditure criteria in the context of our overall capital expenditure forecast.[8] In making its draft decision on our replacement expenditure, the AER has given appropriate consideration to a range of information and assessment techniques, including top-down (such as Repex Modelling and trend analysis) and bottom-up (detailed business case analysis) methodologies. Consistent with the continuous improvement attribute of our asset management system, we acknowledge the AER's comments in its draft decision on matters such as risk quantification and will take these into account during the next regulatory period.

Noting the impact replacement expenditure has on our ability to meet these expectations, our customers reaffirmed through our recent engagement that they expect us to continue to maintain our current levels of network reliability over the long-term—and even that the COVID-19 pandemic had caused some customers to think about their reliance on the electricity network differently:

> *'It did impact on my electricity as there were often outages during the evening and I was stuck inside with no power. I couldn't get my car out of the garage because of the electric garage door lift.'*
>
> *'My reliance on the network was even more critical at this time as I was unable to attend the office to perform my work.'* [9]

Our revised proposal's replacement expenditure forecast is shown in Figure 1–1 and Table 1–1. Our revised proposal for this category is unchanged from our initial proposal and the AER's draft decision, with the exception of minor movements due to changes in real price escalation (and which are applicable throughout our capital and operating expenditure forecasts).

We note that our customer-initiated asset relocation expenditure during the next regulatory period may be higher than our forecast, due to an increase in road, rail and other infrastructure projects driven by government stimulus measures supporting the economic recovery from COVID-19—as explained in Appendix A of our 2021-26 Revised Regulatory Proposal Overview. However, consistent with our revised proposal's approach to connections and augmentation capital expenditure, we do not consider that these changes are likely to be material in the context of our aggregate net capital expenditure forecast. We have therefore accepted the AER's draft decision values.

7 JEN, *2021-26 Electricity Distribution Price Review Regulatory Proposal – Attachment 05-01*, 31 January 2020, p. 21.

8 AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-16.

9 Feedback from our People's Panel, as discussed further in Attachment 01-02.

Figure 1–1: How our replacement expenditure compares (5 years, $ June 2021, millions)

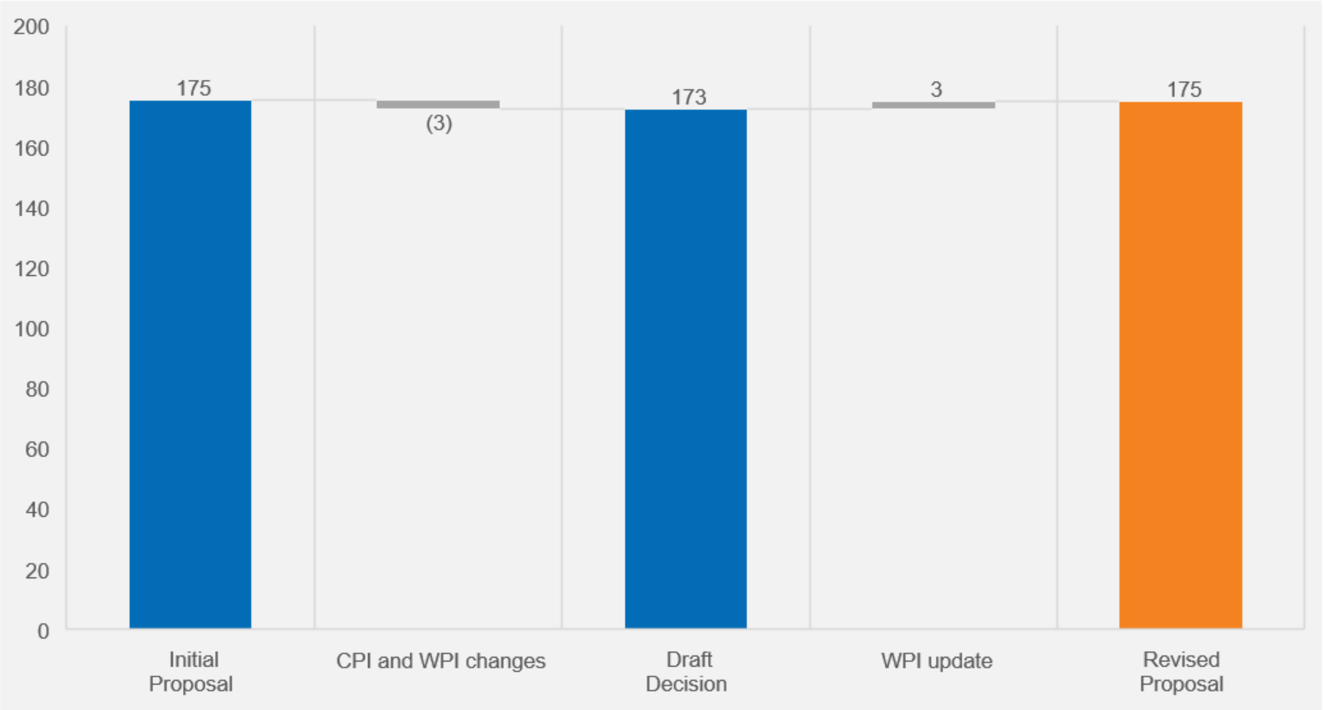


Table 1–1: Forecast replacement expenditure by asset group (5 years, $ June 2021, millions)

Replacement expenditure by asset group	Initial Proposal	Draft Decision	Revised proposal
Poles	18.6	18.4	18.6
Pole top structures	25.9	25.4	25.9
Overhead conductors	12.1	11.9	12.1
Underground cables	9.4	9.3	9.5
Service lines	20.7	20.6	20.8
Transformers	13.2	13.2	13.3
Switchgear	26.0	25.7	26.0
SCADA, network control & protection systems	29.1	28.8	29.1
Protection systems	23.2	22.9	23.2
Communications	4.5	4.4	4.5
Other	1.5	1.5	1.5
Other	55.7	55.2	55.8
Customer initiated asset relocations	36.7	36.4	36.8
Emergency recoverable works	11.8	11.7	11.8
Other assets	7.2	7.1	7.2
Gross replacement capital expenditure	**210.9**	**208.4**	**211.1**
Capital contributions[1]	(35.6)	(35.8)	(35.8)
Net replacement capital expenditure	**175.3**	**172.7**	**175.3**

(1) Capital contributions apply to customer-initiated asset relocation works.

2. Connections expenditure

We need to connect new customers to our network and augment or alter existing network connections to meet specific customers' needs. We developed our connections expenditure forecast to meet the objective set out below, as set out in our initial proposal.[10]

> Connect new customers to our network and meet the changing energy needs of existing customers, ensuring we can meet or manage expected demand for all customers at the least cost over the long-term.

JEN welcomes the draft decision's finding that, prior to the effects of COVID-19, our net connections capital expenditure is reasonable from a top-down perspective. The AER's draft decision adopted our forecast and applied an adjustment to reduce net connections expenditure by nine per cent to account for the expected impact of COVID-19 on forecast construction activity.[11] The AER noted it would, in making its final determination, consider whether any new information would materially affect our connections forecast.[12]

Although we have some reservations regarding the analysis and methodology used in the draft decision, we note the decision was made at a time of heightened uncertainty and in a period that lacked robust external macroeconomic forecasts which could reliably quantify the impacts of the COVID-19 pandemic. Having conducted a detailed analysis and re-run our forecasting methodologies using recently available information, we consider that a forecast using an alternate methodology would not be materially different from the draft decision. We discuss this further in section 2.1.

Consistent with our approach to augmentation expenditure, our revised proposal aligns with the draft decision except for adjustments to account for real price escalation. However, due to the timing of our revised proposal, we were unable to update the AER's adjustment to reflect the latest the Housing Industry Association (**HIA**) forecasts,[13] and we therefore request that the AER apply this updated data in its final determination. Figure 2–1 and Table 2–1 compare our initial proposal, the AER's draft decision and our revised proposal connections expenditure forecasts.

[10] JEN, *2021-26 Electricity Distribution Price Review Regulatory Proposal – Attachment 05-01*, 31 January 2020, p. 65.

[11] AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-28.

[12] AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-29.

[13] Released on 19 November 2020.

Figure 2–1: How our connections expenditure compares (5 years, $ June 2021, millions)

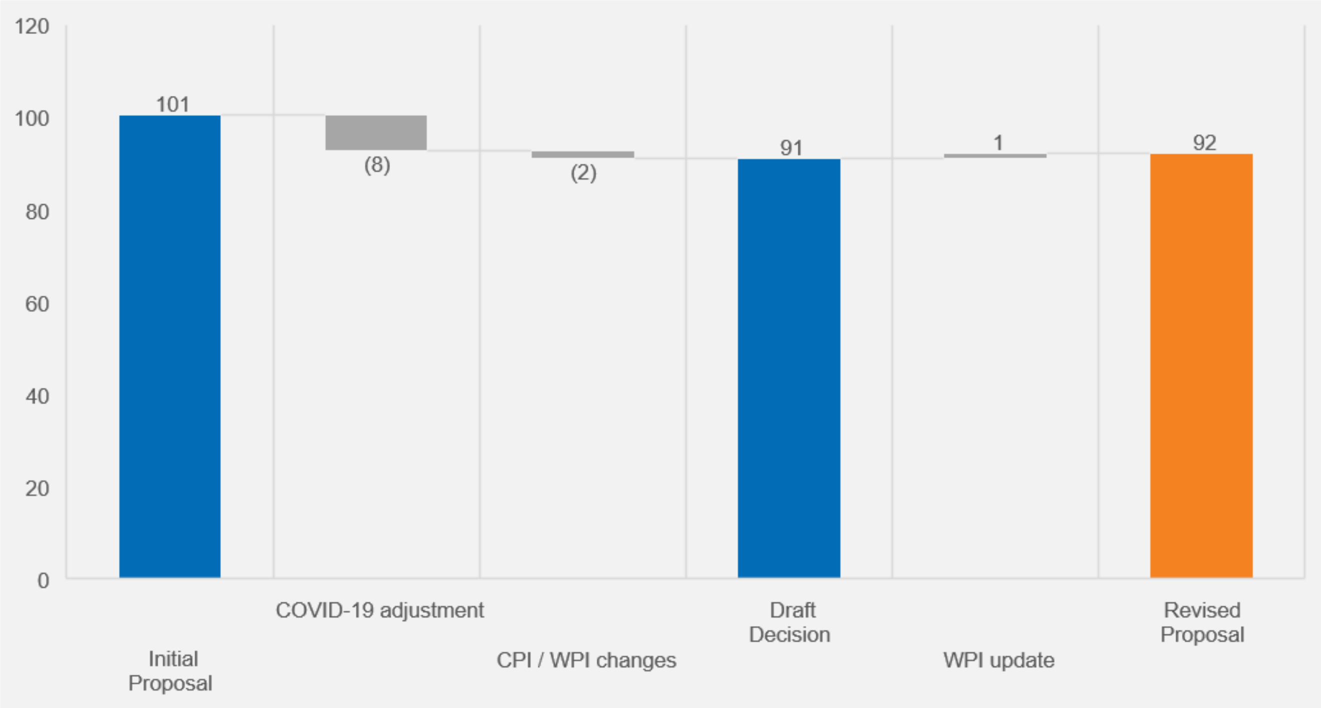


Table 2–1: Forecast connections expenditure by connection subcategory (5 years, $ June 2021, millions)

Customer category	Initial Proposal	Draft Decision	Revised proposal
Residential	51.2	47.0	47.1
Commercial/industrial	111.0	99.9	100.8
Subdivision	55.8	51.1	51.3
Embedded generation	-	-	-
Total gross connections expenditure	**218.0**	**198.0**	**199.1**
Capital contributions[1]	(117.4)	(106.9)	(106.9)
Net connections expenditure	**100.7**	**91.1**	**92.3**

(1) Does not include capital contributions for asset relocation works, which are replacement expenditure – refer to section 1.

(2) Standard control services only.

2.1 Effect of COVID-19 on connections expenditure

While expressing comfort with our underlying methodology and outputs of our connections expenditure forecast, the draft decision reduced our forecast to account for the expected impacts of COVID-19. This adjustment was based on HIA's April 2020 forecasts of residential dwelling commencements. In the draft decision, the AER stated that it would consider any new information which may materially change our connections expenditure forecast, including updated construction forecasts for Victoria, (including those that allow distinctions to be made between types of connection).[14]

As outlined in this section, our actual connections expenditure during the next regulatory period will likely be higher than the amount reflected in the draft decision. However, consistent with our approach to augmentation and customer-initiated asset relocations expenditure, we do not consider that an alternate forecasting approach is likely to represent a material increase in our net capital expenditure from the draft decision, and accordingly we have adopted the draft decision's forecast in our revised proposal. We do, however, request that the AER update

[14] AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-29.

its adjustment methodology using HIA's November 2020 forecasts when making its final determination, as we were unable to incorporate these into our revised proposal due to the submission timeframes.

As discussed further in Appendix A of our 2021-26 Revised Regulatory Proposal Overview, the Australian and Victorian Governments have implemented significant measures to support the economic recovery from COVID-19. These measures will underpin construction activity, which in turn will drive continued customer demand for electricity connections. Key programs include:

- stimulus to encourage private residential construction investment—such as the Federal Government's HomeBuilder program[15]
- direct investment in public housing—such as the Victorian Government's $5.3B Big Housing Build program[16]
- direct investment in commercial and industrial facilities—through the Federal Government's Modern Manufacturing Strategy[17]
- fast-tracking approvals for private investment—such as under the Victorian Government's Development Facilitation Program.[18]

In the months leading up to the publication of the draft decision, there was considerable uncertainty and reduced availability of robust macroeconomic forecasts. Generally, we would consider that the HIA data used in the draft decision may only be relevant to the residential and subdivision parts of our connection expenditure—noting that these comprise only 29 per cent of our initial proposal's net connections expenditure. As illustrated in Figure 2–2, the majority of our forecast net connections expenditure relates to non-residential connections, and there is, therefore, a risk that applying an adjustment based on residential data across our entire connections program may not be fully reflective of the drivers of this category of expenditure. We discuss how we have separately considered the effects of COVID-19 on our major customer and general connections expenditure forecasts in the sections below.

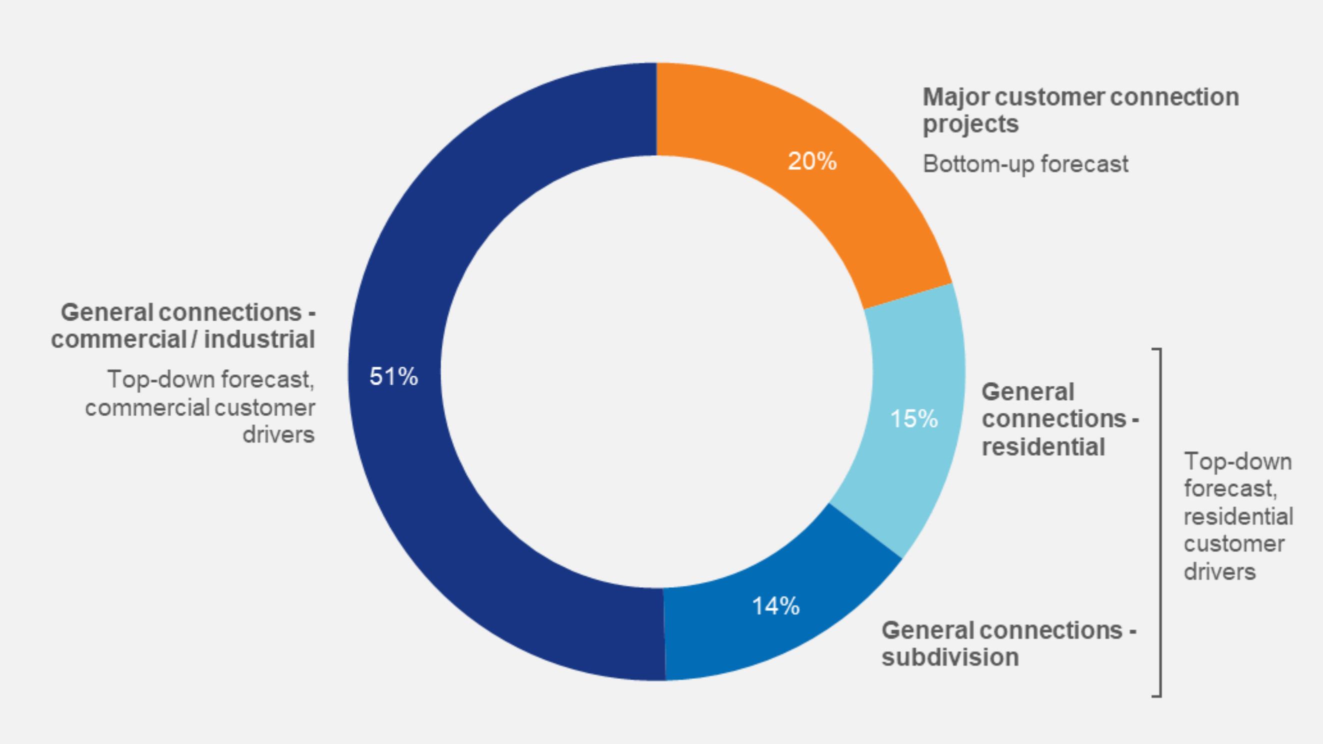
15 https://treasury.gov.au/coronavirus/homebuilder

16 https://www.budget.vic.gov.au/place-call-home-victorias-big-housing-build

17 https://www.minister.industry.gov.au/ministers/karenandrews/media-releases/2020-21-budget-manufacturing-australias-future

18 https://www.planning.vic.gov.au/policy-and-strategy/development-facilitation-program

Figure 2–2: Composition of our initial proposal's net connections expenditure forecast



2.1.1 Major customer connection projects

Our major customer connection projects (20 per cent of our net connections expenditure) are forecast on a bottom-up basis using the most recent information available directly from the proponents of these specific projects. As this part of our forecast reflects specific and known customer requirements, it would not ordinarily be appropriate to apply a top-down adjustment to these major projects based on a change in residential construction sector outlooks. Rather, any changes to our major projects should instead reflect a change in these individual customers' requirements.

When developing our revised proposal, we considered the impact of the most recent available customer information on our bottom-up forecasts for our major customer connection projects. Largely due to expanded requirements of a major government infrastructure project and the addition of a large new traction (rail) supply project, we expect a significant increase in our gross connections expenditure from the amount we forecast in our initial proposal. However, after accounting for the customer contributions associated with these projects, the increase in our net connections expenditure is relatively small. We therefore consider that the amount for major customer connection project expenditure included in the AER's draft decision—and accepted by us—represents a minimum level of net capital expenditure that we are likely to incur during the next regulatory period.

2.1.2 General connections

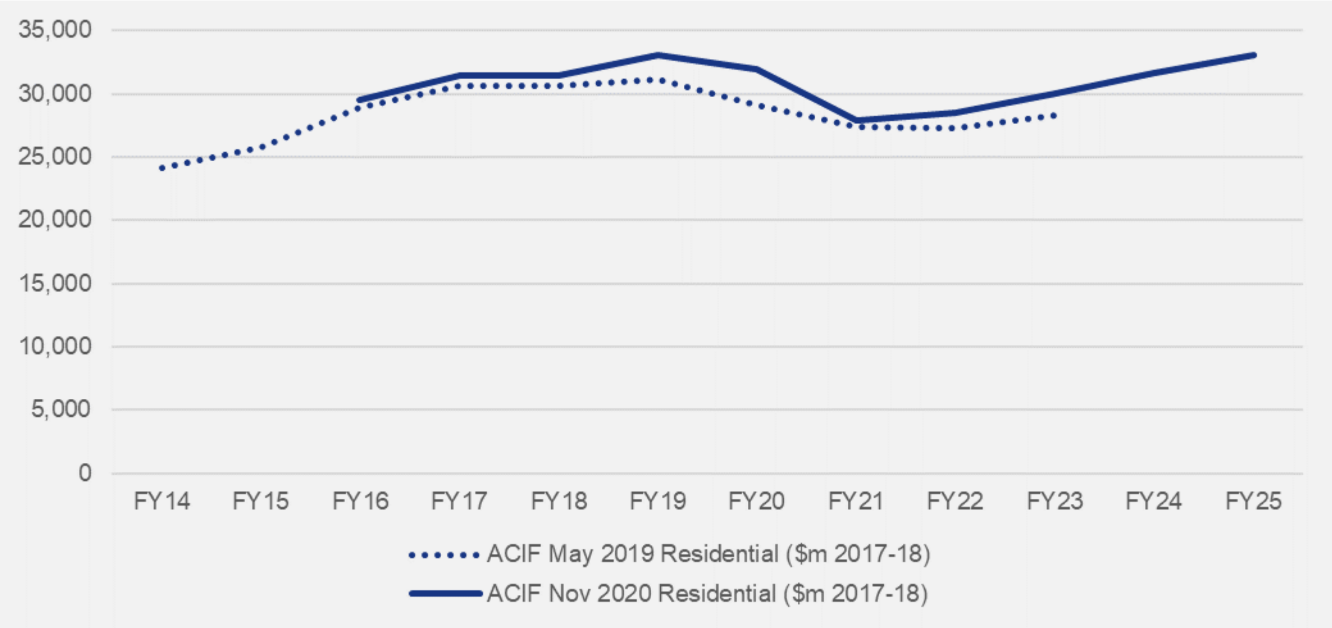
As outlined in our initial proposal, we forecast our general connections expenditure on a top-down basis using macroeconomic and other trend data.[19] While our commercial and industrial general connections projects are forecast using the same modelling approach as residential categories, the drivers of this expenditure can differ from the drivers of residential connections. To reflect this difference, our long-standing forecasting methodology for general commercial and industrial connections uses forecasts of building and construction activity for certain non-residential sectors, sourced from the Australian Construction Industry Forum (**ACIF**). We note that the usual publication cycle for these forecasts was disrupted during 2020 and that ACIF forecasts incorporating the impacts of COVID-19 only became available after the AER made its draft decision. We have considered ACIF's updated forecasts and their potential impact on our general connections forecast when developing our revised proposal.

19 JEN, *2021-26 Electricity Distribution Price Review Regulatory Proposal – Attachment 05-01*, 31 January 2020, p. 68.

Residential and subdivision general connections

For residential (including subdivision) construction activity in Victoria, ACIF's November 2020 forecasts show a rebound in activity between FY21 and FY22, followed by a period of strong growth. We also note that the recovery timeframe shown in ACIF's November 2020 residential forecast is broadly consistent with the assumption outlined in the draft decision that the effects of COVID-19 on construction will have ended by July 2022.[20] ACIF's residential construction forecasts for Victoria are illustrated in Figure 2–3.

Figure 2–3: ACIF Victorian residential sector building and construction activity

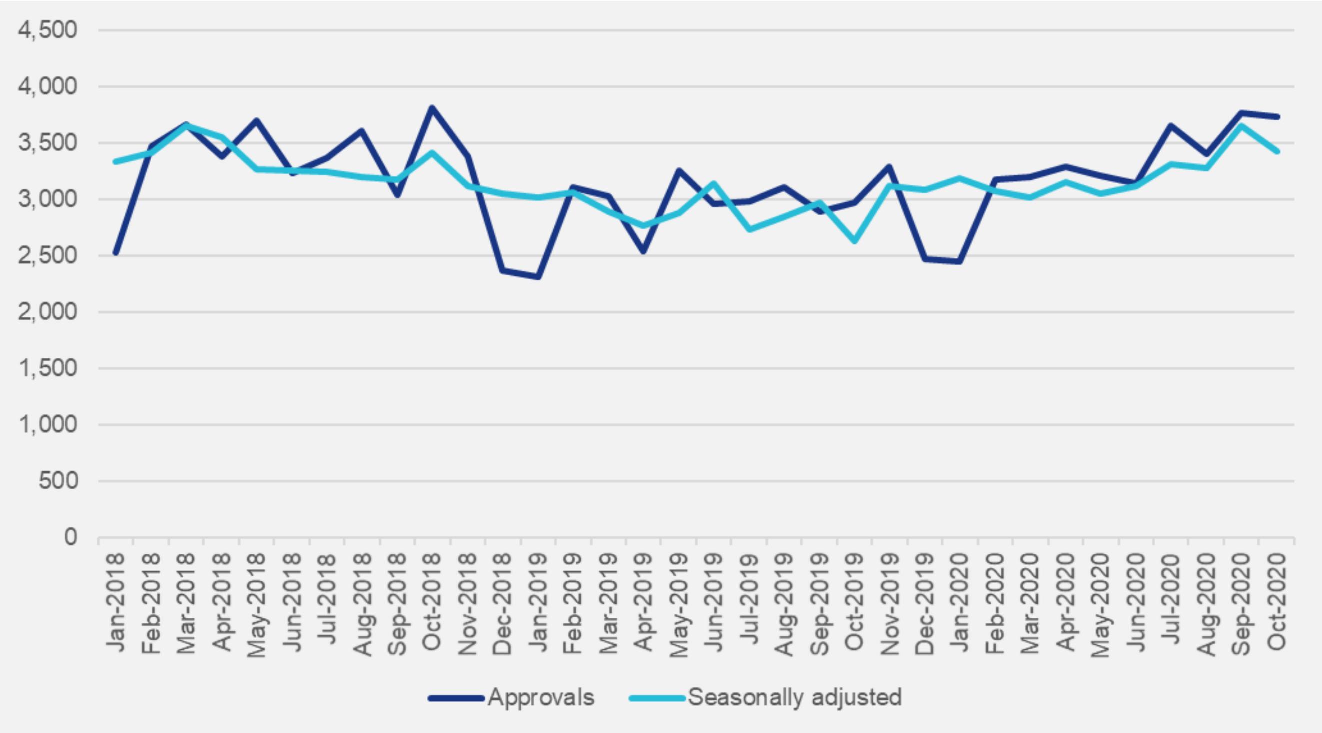


(1) Based on Australian Construction Industry Forum, Australian Construction Market Reports May 2019 and November 2020.
(2) May 2019 data has been adjusted for inflation.

Although JEN's residential and subdivision general connections expenditure has previously been forecast using trends in our customer numbers, we note that the similarities in the trends shown between ACIF's pre-pandemic (May 2019) and post-pandemic (November 2020) forecasts. These trends suggest that any further negative adjustments to our forecast expenditure for these categories would likely lead to a material underestimation of the efficient expenditure required to meet residential connection requests during the next regulatory period. This is further supported by the increase in residential building approvals in Victoria seen recent months—a leading indicator of future connections activity—as illustrated in Figure 2–4.

[20] AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-29.

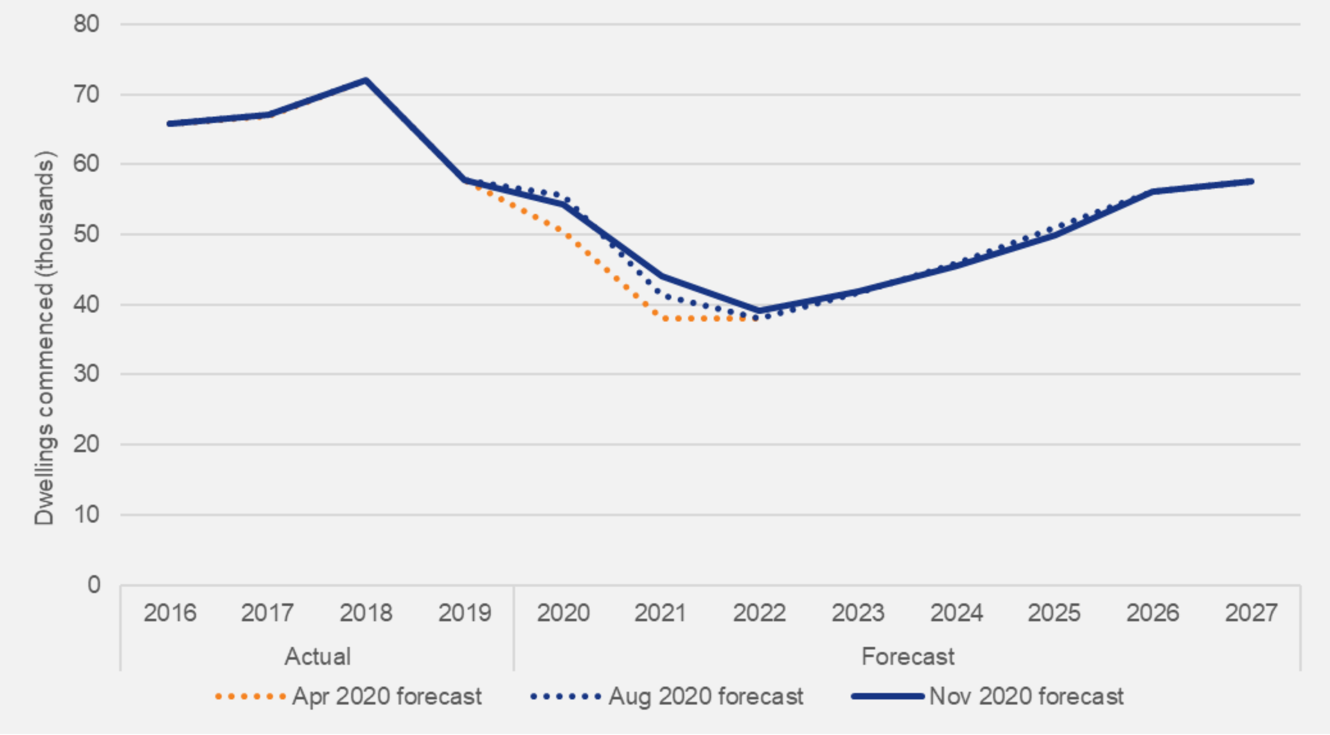
Figure 2–4: Victorian house dwellings approved (all sectors)



(1) Based on Australian Bureau of Statistics, *Building Approvals, Australia, September 2020*, ABS Cat. No. 8731.0, 1 December 2020.

Finally, we note that the August and November 2020 iterations of HIA's dwelling start forecasts issued since the April 2020 data used in the draft decision appear to indicate a slight softening of the impact of COVID-19 on residential construction in Victoria, as illustrated in Figure 2–5. Taken together with the trends suggested by the data above, we consider that the adjustment applied in the draft decision is more likely to overstate the negative impacts of COVID-19 than to understate these effects.

Figure 2–5: HIA Victorian total dwelling starts

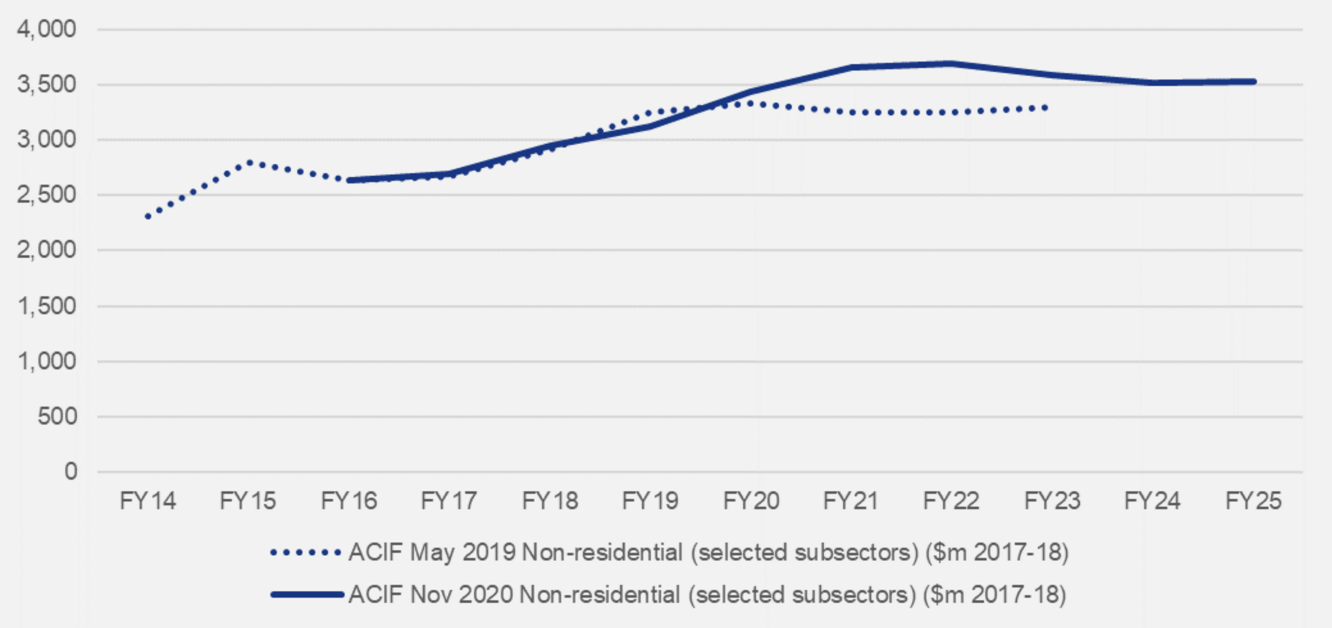


(1) Based on HIA Economics, Long Term Housing Projections.
(2) Calendar years shown.

Commercial and industrial general connections

ACIF's updated forecasts for non-residential construction subsectors continue to show a similar trend to the May 2019 forecasts we used to develop our initial proposal. These show growth plateauing (without a significant decline in activity) from FY20, albeit at an even higher level of activity than was forecast pre-pandemic. ACIF's outlook for selected non-residential subsectors, which we use in our forecast, is illustrated in Figure 2–6.

Figure 2–6: ACIF Victorian non-residential sector building and construction activity



(1) Subsectors shown are Industrial, Other Commercial and Non-residential Miscellaneous
(2) Based on Australian Construction Industry Forum, Australian Construction Market Reports May 2019 and November 2020
(3) May 2019 data has been adjusted for inflation.

Similar to residential connections, the consistency in trends between this updated outlook of non-residential construction activity and the pre-pandemic forecasts we used to develop our initial proposal, show that COVID-19 is likely to have a very limited impact on this category of expenditure. This strongly suggests that further reductions for COVID-19, beyond those made in the draft decision, are likely to result in our non-residential general connections expenditure forecast being materially understated.

2.1.3 Aggregate effects

The above section shows broad consistency in forecast construction trends between ACIF's pre-pandemic and updated forecasts, and also notes that updated major customer connection information will have minimal impacts on our net connections expenditure. We therefore consider that an alternative forecasting approach to reflect the aggregate effects of COVID-19 would likely not result in a material change to our net connections expenditure from that which the AER applied in the draft decision.

Furthermore, the results of our alternative forecasting using updated data and consideration of leading indicators such as building approvals strongly suggest that our actual net connections expenditure during the next regulatory period will be at or above the level included in the draft decision. This provides further support for the position that any further reduction to our connections expenditure forecast would not be appropriate, as it would likely result in an amount which is materially lower than the expenditure we will need to meet customer requirements next period.

In light of our similar approach to not incorporating immaterial changes to our augmentation and asset relocation expenditure, we have therefore reflected the draft decision's amounts in our revised proposal, with only minor updates for real cost escalation. However, we request that the AER update its adjustment method to reflect HIA's November 2020 forecasts in the final determination.

3. Augmentation expenditure

Augmentation enlarges our network and its capacity to distribute electricity or otherwise improves the quality or capability of the distribution network. We developed our augmentation expenditure forecast[21] to meet the objectives below, as set out in our initial proposal.[22]

> Meet or manage changes in energy demand from our customers, allowing us to maintain our current levels of network reliability (including the frequency and length of network outages) at the most efficient cost over the long term.
>
> Manage safety, environmental, physical security and cybersecurity risks to as low as practicable at the most efficient cost over the long term and comply with all relevant safety and environmental obligations.

We welcome the AER's overall conclusion that our non-DER augmentation expenditure forms part of a capital expenditure forecast that reasonably satisfies the capital expenditure criteria, noting adjustments for our REFCL program due to changes in our approach to these external obligations.[23] The AER's draft decision separated our augmentation expenditure forecast into two sub-categories—'**traditional augmentation**' and '**REFCL augmentation**'. We have adopted these sub-categories in this document for consistency with the draft decision.

For traditional augmentation, although the AER considered demand forecasts produced by the Australian Energy Market Operator (**AEMO**) in 2019 as being more reasonable than JEN's forecasts from ACIL Allen, it found our forecast expenditure in this category was reasonable, based on high-level trend analysis.[24] The AER did, however, note the potential for COVID-19 to impact demand forecasts and augmentation expenditure, and that it would consider this further in its final decision.[25] Accordingly, in developing our revised proposal, we have assessed the likely effects of COVID-19 on our traditional augmentation expenditure and discuss this in section 3.1.

In relation to our REFCL program, the draft decision acknowledged JEN's application for an exemption for the Coolaroo zone substation which would enable us to pursue a lower-cost technical solution, and therefore included a 'placeholder' value (based on an indicative estimate JEN provided through the AER's information request process) in the draft decision, and noting that we would provide further information in our revised proposal. Consistent with the draft decision and our ongoing engagement with the AER, we have updated our revised proposal to reflect an amended compliance approach to Coolaroo following the granting of exemptions to JEN—this is discussed in section 3.2.

Our revised proposal also includes expenditure necessary for JEN to comply with bushfire mitigation obligations associated with Kalkallo zone substation, discussed in section 3.3. Additionally, we have made minor movements to our forecast expenditure due to changes in real price escalation, consistent with the broader changes across our capital and operating expenditure forecasts.

Figure 3–1 and Table 3–1 compare our initial proposal, the AER's draft decision and our revised proposal augmentation expenditure forecasts.

21 The values shown up to and including section 3 of this document exclude augmentation expenditure relating to DER integration. To align with the categorisations used in the AER's draft decision capital expenditure document, all DER integration expenditure is discussed in section 4.

22 JEN, *2021-26 Electricity Distribution Price Review Regulatory Proposal – Attachment 05-01*, 31 January 2020, p. 73.

23 AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-26.

24 AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-27.

25 AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-27.

Figure 3–1: How our augmentation expenditure compares (FY22-26, $ June 2021, millions)

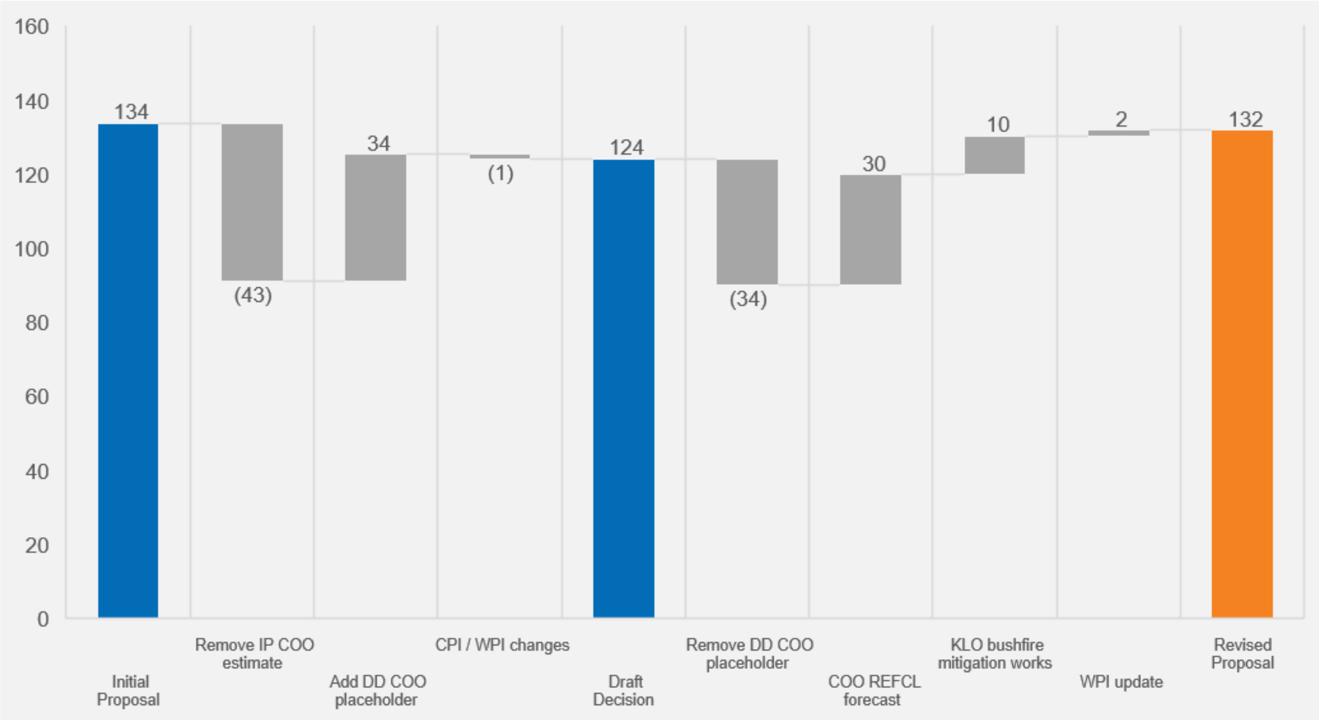


Table 3–1: Forecast augmentation expenditure by driver and asset type (5 years, $ June 2021, millions)

	Augmentation expenditure by asset type	Initial Proposal	Draft Decision	Revised proposal
Traditional augmentation	Subtransmission Substations, Switching Stations, Zone Substations	8.8	8.8	8.9
	Subtransmission Lines	15.2	15.1	15.2
	HV Feeders	48.6	48.1	48.6
	Distribution Substations	17.0	16.7	17.0
	LV Feeders	1.0	1.0	1.0
	Other assets	-	-	-
	Sub-total – traditional augmentation	**90.6**	**89.7**	**90.7**
REFCL augmentation	Subtransmission Substations, Switching Stations, Zone Substations	35.8	28.5	17.9
	Subtransmission Lines	6.0	4.7	4.0
	HV Feeders	1.3	1.0	19.2
	Distribution Substations	-	-	-
	LV Feeders	-	-	-
	Other assets	-	-	-
	Sub-total – REFCL augmentation[1]	**43.1**	**34.3**	**41.2**
Total augmentation expenditure		**133.7**	**124.0**	**131.8**

(1) The 'REFCL augmentation' sub-category reflects expenditure related to JEN's compliance with REFCL and related bushfire mitigation obligations.

3.1 Effect of COVID-19 on traditional augmentation expenditure

Although accepting our forecast of traditional augmentation expenditure, the draft decision states that AEMO's forecasts of maximum demand are more reasonable than JEN's forecasts, developed by consultant ACIL Allen. The AER further considers that AEMO's updated 2020 terminal station forecasts are likely to be lower due to COVID-19, and that it will assess whether COVID-19 would lead to a material reduction in JEN's augmentation expenditure when making its final decision.[26]

For completeness, we note that of our program assessed by the AER as traditional augmentation expenditure, only $55 million[27] relates to projects where growth in forecast maximum demand is the major driver.[28] The remaining $35 million of our traditional augmentation forecast relates to projects where growth in forecast maximum demand is not the sole driver of the investment—these projects have a mix of drivers, some of which are unrelated to changes in demand, such as asset condition, voltage standard conversions, supply quality and environmental compliance.

Given the draft decision's commentary on the potential impact of COVID-19 on forecast demand is primarily relevant to projects where the major driver is demand, the remainder of the discussion in this section focusses on our proposed $55 million of demand-driven augmentation expenditure.

Our revised proposal does not make any changes to our demand-driven augmentation expenditure from our initial proposal.[29] We consider that, in aggregate, COVID-19 will not lead to a material reduction in our augmentation expenditure during the next regulatory period. We outline the importance of spatial demand diversity—which is not shown in AEMO's forecasts—as a driver of our augmentation expenditure in section 3.1.1, and then further explore the potential impacts of COVID-19 on spatial demand and our augmentation program in section 3.1.2.

3.1.1 Spatial demand diversity must be considered when assessing augmentation expenditure

Forecasts of maximum demand are typically discussed and compared at a network-wide level. However, it is critical to recognise that we apply our probabilistic planning methodology to assess the customer supply risks and costs of distribution network level constraints at specific locations—and therefore it is the forecast of maximum demand at a specific location (spatial forecasts) which drive our augmentation expenditure. Our proposed augmentation program, which covers assets at all levels of our network, cannot be assessed solely based on a system-level forecast of demand, such as AEMO's terminal station forecasts.

3.1.1.1 Our demand forecasting process

To inform the development of our network augmentation plans, we undertake a comprehensive demand forecasting process, which balances top-down and bottom-up methodologies. Our forecasting process comprises several phases involving building up spatial forecasts and then reconciling these to our externally sourced (from ACIL Allen Consulting) top-down system forecast. These phases are summarised in Figure 3–2 and explained further below.

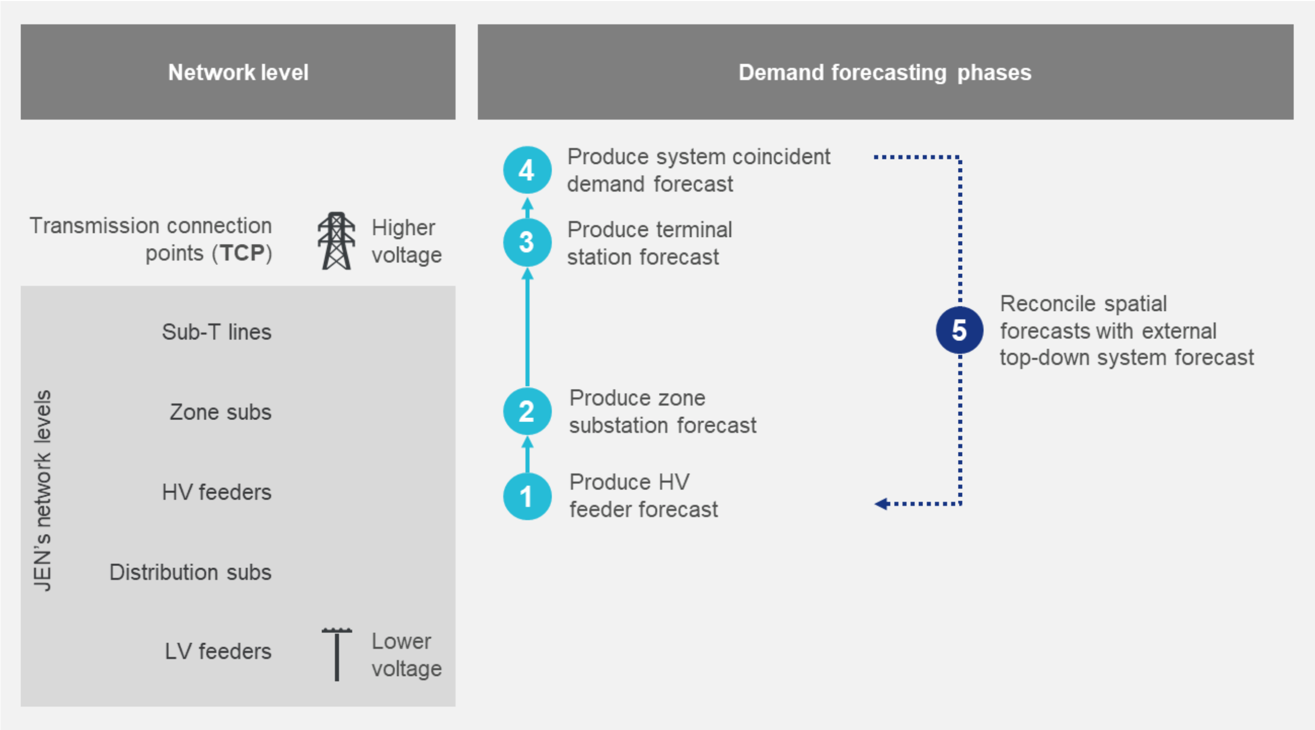
[26] AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-27.

[27] Representing approximately seven per cent of our initial proposal's gross capital expenditure forecast.

[28] AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-26.

[29] With the exception of minor adjustments to real cost escalation.

Figure 3–2: Summary of our demand forecasting process



Phases 1 to 3 use local information about our customers and communities to develop spatial forecasts.

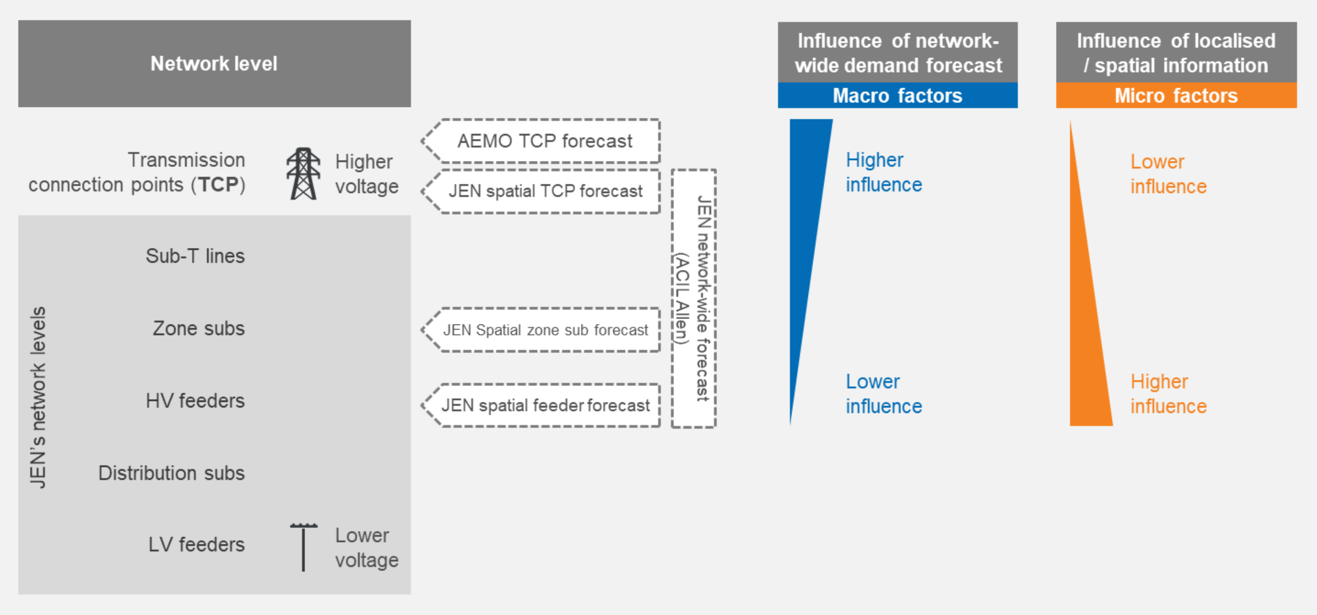
Phase 1 involves developing forecasts for each high voltage (**HV**) feeder, capturing recent trends in local usage and significant additions or reductions in load based on information about changes in local customer demand, such as new residential subdivisions and commercial and industrial development projects. During this phase, we also consider committed load transfers resulting from feeder reconfigurations or other network projects.

Phase 2 translates information at a feeder level into zone substation demand forecasts. In this process, we reconcile feeder demand to historical maximum demand at zone substations (including weather normalisation) and then apply diversity factors to convert non-coincident feeder demand forecasts into zone substation peak demand forecasts. We then adopt a similar approach in phase 3 to translate zone substation demand forecasts into terminal station forecasts.

Phases 4 and 5 then focus on reconciling terminal station forecasts to our externally sourced system-wide forecasts. These phases utilise diversity factors to translate terminal station forecasts into system forecasts, and then scaling our bottom-up spatial forecasts to match the system level forecasts in aggregate. This ensures our spatial forecasts are aligned with the macro factors—such as the economic outlook for Victoria—which are inputs to the top-down system forecast.

Spatial demand forecasts at different levels of our network are subject to different degrees of influence by network-wide (macro) factors and local (micro) factors. For spatial forecasts which relate to HV feeders, the influence of local factors is greater, and the influence of the network-wide (top-down) forecast is lesser when compared to forecasts at a zone substation or transmission connection point level, as illustrated in Figure 3–3.

Figure 3–3: Demand forecasts are influenced differently throughout the network



3.1.1.2 Implications of spatial demand variance for augmentation expenditure

This distinction between network-wide maximum demand forecasts and spatial maximum demand forecasts is particularly relevant for a distribution network such as JEN, given our network area covers a diverse range of suburbs and customer types. Over the past decade, our network has seen divergent demand trends in different locations of our network. This includes fast-growing residential and commercial loads associated with greenfield developments in Melbourne's north growth corridor, growth in inner suburbs due to infill or brownfield developments, and falling maximum demand in some industrial areas as some large manufacturing customers have shut down.

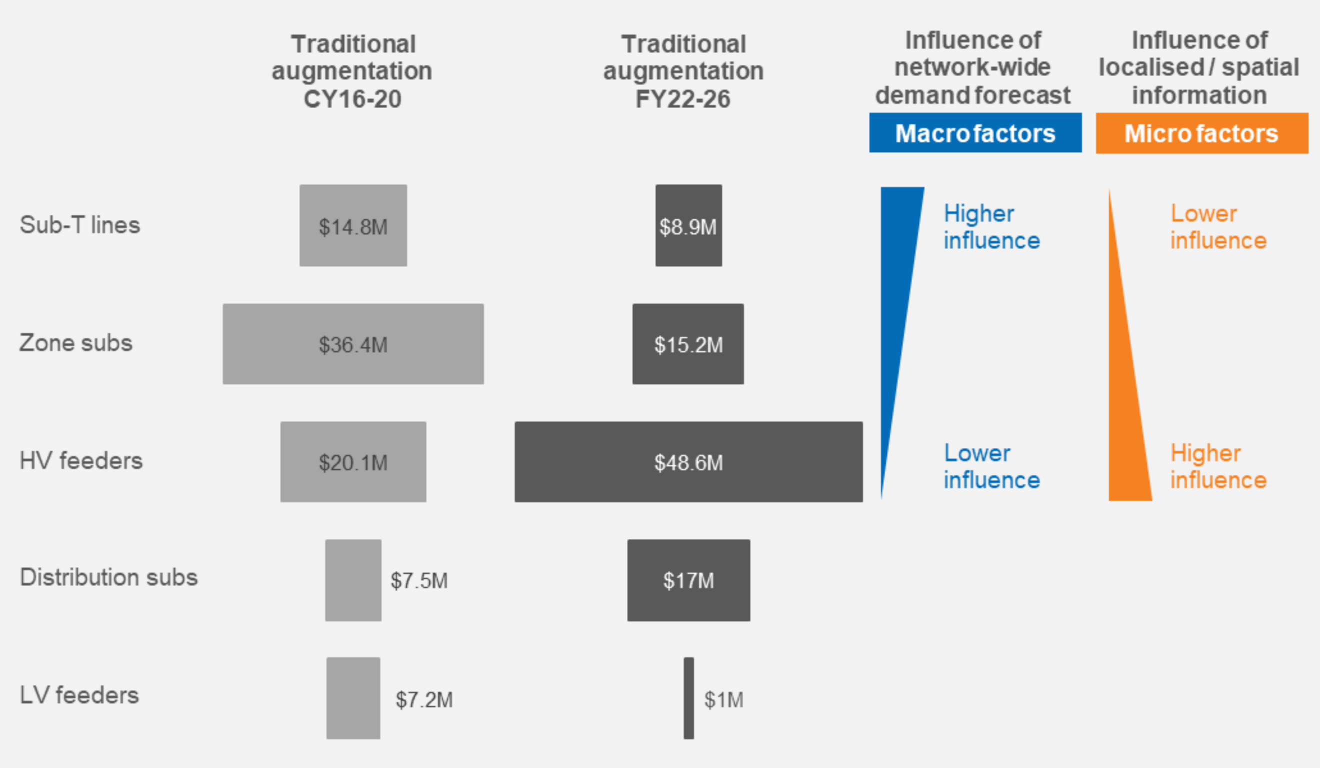
Notably, these positive and negative changes in maximum demand at a zone substation level have occurred *simultaneously*—meaning that although maximum demand may appear to be flat at a network-wide level, this is a function of offsetting increases and decreases of the same magnitude in maximum demand at a lower spatial level within our network. Although increasing maximum demand at a particular location is a driver of augmentation expenditure, decreases in maximum demand at another location do not result in 'negative' augmentation expenditure. For this reason, the comparison of system-level demand growth and the corresponding augmentation expenditure across regulatory control periods may underestimate required augmentation expenditure, and should not be used as the basis for any negative adjustments to forecast expenditure. This is because the relationship they seek to analyse may not account for changes in spatial diversity within a network over time.

Over the next regulatory period, we expect to continue to see contrasts in maximum demand growth between different supply areas (zone substations). In our initial proposal, we showed both areas of low growth or decline (such as Broadmeadows and Thomastown) and areas of strong growth (such as Fairfield and North Essendon).[30] Our forecast augmentation expenditure reflects this spatial diversity, with a large portion of our growth-related augmentation relating to localised assets such as HV feeders—more so than in the current regulatory period as is illustrated in Figure 3–4. As noted above, when compared to assets such as sub-transmission lines, the spatial demand forecasts that determine the need for HV feeder augmentation are:

- subject to a greater degree of spatial variation than the network-wide average (i.e. they are more heavily influenced by location-specific factors)
- subject to a lesser degree of influence by the top-down network maximum demand forecast (i.e. they are less sensitive to changes in the top-down maximum demand forecast).

30 JEN, *2021-26 Electricity Distribution Price Review Regulatory Proposal – Attachment 05-01*, 31 January 2020, pp. 79-80.

Figure 3–4: JEN's historical and forecast traditional augmentation expenditure by network level



Furthermore, the draft decision notes that the AER will consider whether AEMO's 2020 transmission connection point forecasts for JEN's network materially differ from its 2019 forecasts.[31] Even though these forecasts do not reflect any of the spatial diversity in our network, we note that AEMO's 2020 forecasts for JEN's transmission connection points[32] show a material shift upward compared to its 2019 forecasts. This is likely due to the forecasting process AEMO employs where state-wide demand is apportioned to transmission connection points based on most recently available actual information. In addition to the issues associated with spatial diversity discussed previously, such volatility in this forecast is a further illustration of why this information should not be solely used to determine our distribution network augmentation requirements. As an aside, we also note that AEMO's 2020 forecast for our connection points shows a small positive growth trend over ten years, compared to a small negative growth trend shown in its 2019 forecast.

Therefore, due to the significance of spatial demand diversity in driving our forecast augmentation program, and the other limitations associated with AEMO's transmission connection point forecasts, any top-down adjustments to our program on the basis of system-wide or transmission connection point forecasts are unlikely to reflect an efficient forecast of the augmentation expenditure we require to meet expected demand.

3.1.2 COVID-19 is not forecast to materially reduce our augmentation expenditure

Consistent with the draft decision, we have considered the potential effects of COVID-19 on our augmentation expenditure when developing our revised proposal. Overall, we consider that COVID-19 will not have a material impact on our aggregate level of augmentation expenditure during the next regulatory period. Therefore, we have not changed our forecast from the draft decision except for minor updates to real cost escalation.

To assess the potential impacts of COVID-19 on our portfolio of demand-driven augmentation projects, we updated our demand forecasts in line with the process outlined in section 3.1.1.1. We then used our probabilistic network planning methodology to apply these updated demand forecasts to reassess (by considering the individual value of load at risk in relation to each network constraint) the 18 augmentation projects contained in

[31] AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-27.

[32] Provided by AEMO to JEN in October 2020.

our forecast which could be sensitive to changes in forecast demand growth, consistent with the network planning process we undertake annually.

Through this process, we found that the optimal investment timing for two of our HV feeder projects was no longer within our next regulatory period. These projects are the reconfiguration of feeder SBY24 (Sunbury area) and the construction of new feeder TMA15 (Tullamarine area), with a combined cost of $3.3M. Both of these projects were planned for the later part of our next regulatory period (with the majority of expenditure to be incurred in FY24 and FY25), and both were designed to accommodate some load from existing adjacent feeders, alleviating and providing a greater balance in the energy at risk across these feeders. Reassessing these projects using our updated spatial forecasts shows that although a material amount of energy at risk will continue to exist for these local areas throughout the next regulatory period, there is likely to be a marginal lessening in the growth of these localised risks, therefore we are able to reschedule the optimal timing of the augmentation works to FY27. We do not consider that these two projects represent a material reduction in our demand-driven augmentation expenditure.

Our re-assessment of the remaining 16 projects did not result in any reductions to our forecast augmentation expenditure, with our analysis confirming that undertaking each of these projects during the next regulatory period provides a net benefit to customers. The optimal timings of augmentation projects later in a planning period are inherently more sensitive to changes in spatial demand forecasts (as changes in growth may compound over time) than those planned for the near-term. However, our analysis did confirm that our other demand driven augmentation projects planned for the second half the next regulatory period remain prudent. These projects relate to areas such as Coolaroo, Somerton, Flemington, Fairfield and North Essendon. We have a high degree of certainty around growth in customer loads in these areas due to major property developments and other customer projects for which we are already seeing corresponding connections expenditure—a leading indicator of future (shared network) augmentation requirements, as new residential loads usually take several years to fully ramp up. This includes, for example, the commencement of construction for the redevelopment of Moonee Valley Racecourse[33] (further contributing to the significant energy at risk associated with the Brunswick Terminal Station-North Essendon subtransmission line) and the continuation of the YarraBend development[34] (a key driver of our projects to mitigate supply risks in the Fairfield and Alphington areas).

Furthermore, we have considered the potential that structural changes in customer behaviour—and therefore demand—may emerge throughout the next regulatory period during the recovery from COVID-19, and that these changes could place upward pressure on our augmentation expenditure. Although there is uncertainty associated with these changes, and their precise implications for our network augmentation program are currently difficult to quantify, COVID-19 has already caused us to have to consider a range of new scenarios, factors and customer behaviours as part of our network operational planning for summer 2020-21, as shown in the case study below.

Case study – Factoring COVID-19 into our distribution substation planning for summer 2020-21

Peak demand occurs for the majority of our distribution substations on days of extreme ambient temperature during the summer period (October to March). In line with our customers' expectations around maintaining current outage lengths and frequency over the long-term, we routinely evaluate and assess the customer loads at risk for our distribution substation population to ensure we have adequate operational plans and holdings of spare equipment in place ahead of summer, and to aim to avoid an increase in the proportion of these assets which are 'overloaded' (i.e. maximum demand above cyclic rating).

In previous summers, we have typically seen some residential customers reduce their demand as they travel during the holiday period, and likewise for some businesses as they may close during the summer holiday period. Both of these influences can have the effect of offsetting some of the upward pressure on maximum demand for certain distribution substations, and are already factored into our demand forecasts and distribution substation augmentation program.

However, when we undertook this exercise in preparation for summer 2020-21, we had to adopt a new scenario-based approach, as we had no historical data on the impacts of a widespread pandemic (or the associated government health directives) on our customers' electricity demand. The analysis we undertook recognised that some

33 Herald Sun, *Construction starts on new mini suburb in the heart of iconic sporting locale*, 4 September 2020.

34 Burbank Urban, *Burbank Urban Appointed at Yarra Park, Alphington*, July 2020.

of the holiday 'offsetting' effect we typically see may not occur this summer, which could result in higher risk for these assets. We heard from members of our Customer Council who represent commercial customers in our network area that some businesses whose operations were restricted during Melbourne's second lockdown were planning on 'catching up' on lost production and trade during the summer holiday period. Additionally, we considered the potential for different usage patterns as some households continue to work from home and may also defer their summer holiday plans due to travel restrictions and work commitments.

This scenario analysis demonstrated that when combined, these particular changes in customer behaviour from regular pre-pandemic patterns and trends could result in a higher amount of energy at risk on some distribution substations. In some scenarios, the increase in non-coincident demand for some local areas was the equivalent of up to 5 years of (pre-pandemic) demand growth, resulting in an increase in the number of overloaded distribution substations on our network by 22 per cent, which would require a significant expansion in our distribution substation augmentation program to address.

In response to this analysis, we increased our spare stock holdings of transformers and fuses by 40 per cent compared to the previous summer. We will continue to monitor network loadings and impacts after the complete summer period's detailed demand data is available, and factor this into our future asset management plans accordingly.

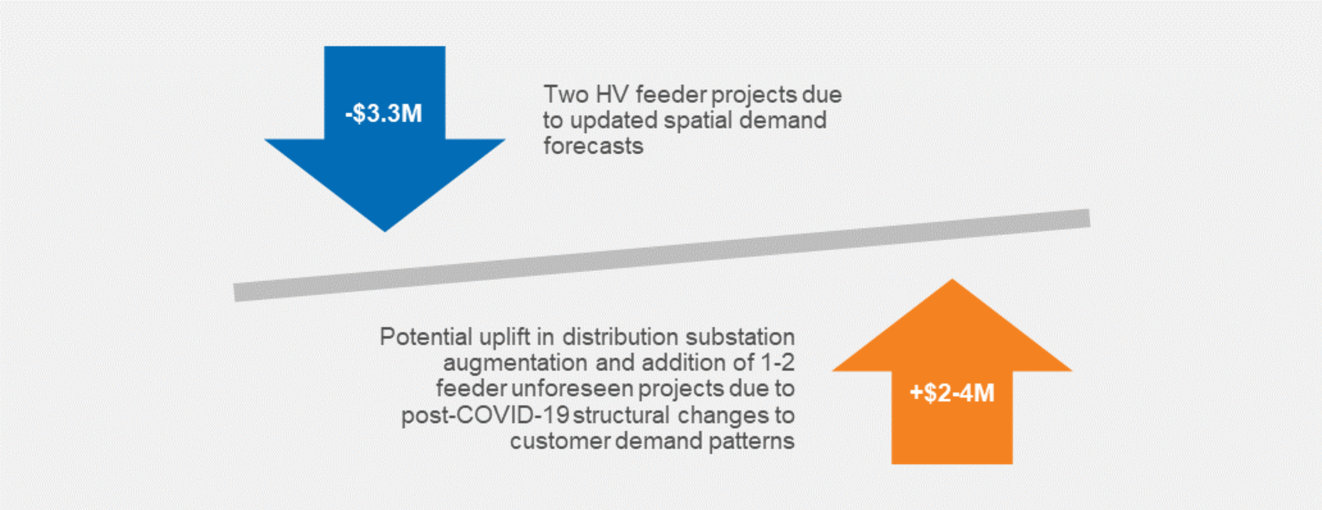
Going forward, we consider that a range of new and unforeseen factors may influence our customers' lifestyles, needs, energy usage and hence maximum demand, and that we will therefore need to adapt the methods we use to plan our network to ensure we can continue to efficiently meet customers' expected demand.

While this case study provides an illustrative example of how we need to approach network planning differently in relation to a particular stage of the pandemic, we expect that going forward we may need to consider a range of scenarios, factors and behaviours. One such trend is the potential for manufacturing and industrial loads in our network (historically home to a number of Victoria's key industrial areas) to increase as existing facilities expand capacity or new facilities are established. A likely driver for this is the federal government's Modern Manufacturing Strategy[35] to improve the competitiveness and resilience of Australia's manufacturing sector and supply chains, particularly for sectors such as food and medical supplies. Another potential trend is for residential loads in outer areas of our network to increase, driven by trends in people desiring more open or green spaces and enabled by the increased acceptability of remote and flexible working arrangements. These (and other emerging) trends may drive the augmentation of assets in locations which we have not currently planned for during the next regulatory period.

Overall, we consider that any changes to our augmentation program will be marginal in nature, and that increases and decreases will broadly offset each other, resulting in no material aggregate change to our forecast—as illustrated in Figure 3–5.

35 https://www.minister.industry.gov.au/ministers/karenandrews/media-releases/2020-21-budget-manufacturing-australias-future

Figure 3–5: Countervailing effects on our demand-driven augmentation



We therefore consider that maintaining our demand-driven augmentation expenditure forecast at the amount included in the draft decision provides a balanced reflection of a ‘neutral’ scenario going forward,[36] in light of:

- the immateriality of anticipated changes to two projects after considering the most recent information available in our spatial demand forecasts—noting that it is our spatial forecasts, not system-wide forecasts, which driver the majority of our augmentation program
- the confirmation through our most recent demand forecast update that the vast majority of our augmentation program remains necessary to meet a realistic expectation of demand over the next regulatory period[37]
- the potential for upward pressure on our augmentation program if unforeseen works are required in response to structural changes in customer behaviour as Victoria emerges from the pandemic.

3.2 Compliance with REFCL obligations for Coolaroo zone substation

We must comply with bushfire mitigation obligations under the Electricity Safety Act 1998 (**ES Act**), Electricity Safety (Bushfire Mitigation) Regulations 2013 (**ES Regulations**) and other related instruments. As Coolaroo zone substation (**COO**) is a prescribed zone substation for the purposes of section 120M of the ES Act, all HV feeders originating from COO must meet certain technical bushfire mitigation requirements (referred to in the ES Act as having the **required capacity**) by 1 May 2023. Providing the *required capacity* on a feeder requires the installation of a REFCL device and other associated equipment or, alternatively, undergrounding the feeder.[38]

JEN’s initial proposal included $43.1M of capital expenditure to allow us to comply with these obligations for COO. This included the installation of two REFCL devices at COO, the construction of a new REFCL-protected zone substation in the Greenvale area (referred to as **GVE**) and other related works.[39] We also noted in our initial proposal that we were pursuing an exemption from obligations under the ES Act and ES Regulations, which would allow us to implement a lower cost technical solution while still providing a commensurate reduction in bushfire ignition risk for the COO area. Our exemption application was supported by detailed bushfire risk assessments of our COO feeders by the Commonwealth Scientific and Industrial Research Organisation (**CSIRO**), and underpinned by significant engagement with ESV.

36 As outlined in Appendix A of JEN’s 2021-26 Revised Regulatory Proposal Overview.

37 Consistent with the capital expenditure objectives and capital expenditure criteria set out in the National Electricity Rules.

38 An exemption order under s 120W of the ES Act was made on 1 October 2020, which exempts underground feeders from having the *required capacity*—this recognises that underground feeders pose a negligible bushfire ignition risk. Energy Safe Victoria has also granted JEN an exemption for underground feeders from related obligations under the Electricity Safety (Bushfire Mitigation) Regulations 2013.

39 JEN, *2021-26 Electricity Distribution Price Review Regulatory Proposal – Attachment 05-01*, 31 January 2020, p. 90.

JEN has now been granted exemptions under section 120W of the ES Act[40] and under regulation 13 of the ES Regulations[41] relating to COO, with these being subject to JEN's compliance with specified conditions. The COO supply area is currently a mix of urban areas classified as Low Bushfire Risk Area (**LBRA**) and semi-rural areas classified as Hazardous Bushfire Risk Area (**HBRA**), and our feeders are a mix of overhead lines and underground cables. Following receipt of the exemption, and in compliance with its conditions, we have revised our COO bushfire mitigation approach. Our revised approach will 'split' the current COO supply area into:

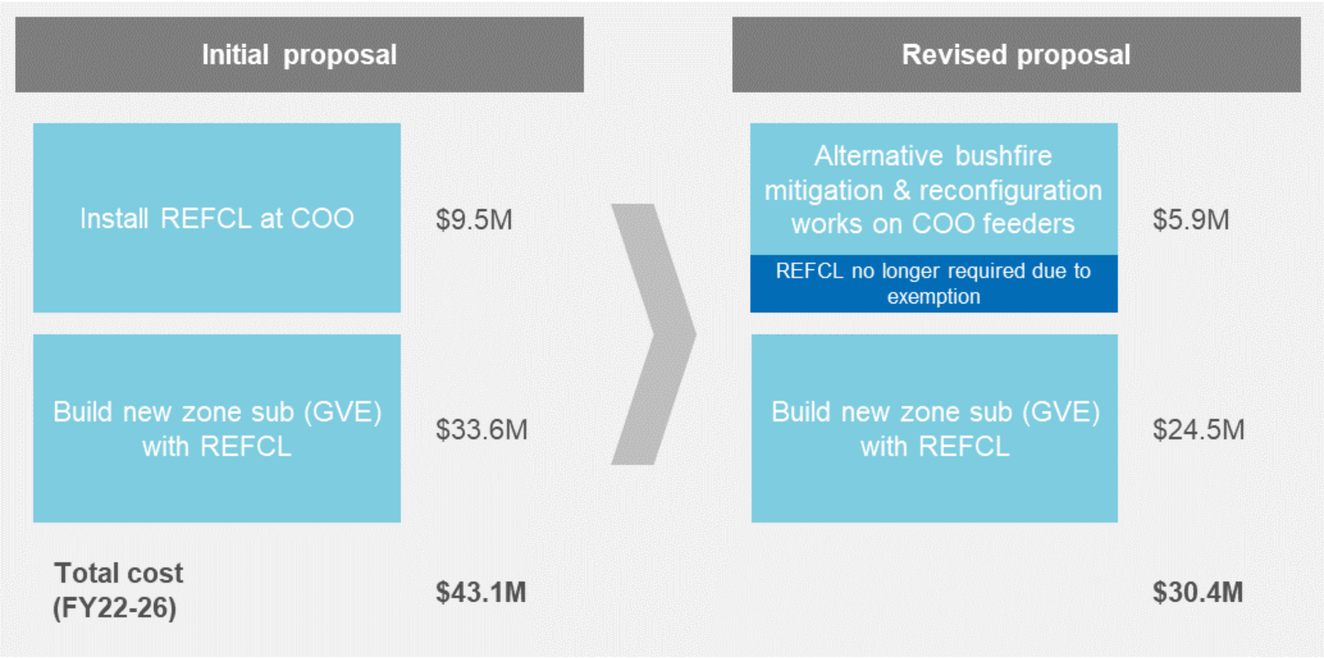
- an urban (low risk) area—to be supplied by our existing Coolaroo zone substation without REFCL protection[42]
- a rural (high risk) area—to be supplied by a new Greenvale zone substation with REFCL protection.

Given this, our revised proposal includes expenditure to:

- construct a new single transformer GVE zone substation, containing one REFCL
- transfer sections of existing COO feeders in the higher risk area to GVE, thus providing these feeders with the *required capacity*
- undertake minor alternative bushfire mitigation works (mostly undergrounding) on 2 km of feeder in the COO urban area, in compliance with the conditions of JEN's exemption under the ES Act.

The differences between our proposed works in our initial and revised proposals are summarised in Figure 3–6. In addition to undertaking alternative bushfire mitigation works at a lower cost than the installation of REFCL equipment at COO, our revised forecast reflects a lower cost of constructing GVE as a single transformer station, rather than with two transformers in our initial proposal.

Figure 3–6: Summary of changes to Coolaroo REFCL compliance approach



In addition to representing a lower capital cost over the next regulatory period, our approach of maintaining the supply of the urban parts of this area from COO (without REFCL protection) represents the most efficient option over the long-term given the need to meet future customer demand as this growth corridor continues to expand.

40 Victoria Government Gazette No. G 47, 26 November 2020, pp. 2392-2395.

41 Granted by ESV on 2 December 2020.

42 Of the 101.3 km of feeders in the non-REFCL protected urban area, 82.8 km are underground and hence not required to have *required capacity* due to the exemption made in October 2020 under the ES Act. Of the remaining 18.5 km overhead feeders, 16.5 km have been assessed by CSIRO as low risk and do not have to have *required capacity* under JEN's ES Act and ES Regulation exemptions, and we will undertake works on the remaining 2 km to underground or otherwise make these sections low risk, as required by the exemptions.

For further information, refer to Attachment 04-03, while Attachment 04-04 details our cost estimate for these works.

We have also revised our forecast for our REFCL compliance operating expenditure step change to cover the operating expenditure associated with our COO/GVE bushfire mitigation approach, including annual fault testing for GVE. This is described further in Attachment 05-01.

3.3 Compliance with REFCL obligations for Kalkallo zone substation

JEN's revised capital expenditure forecast includes mandatory bushfire mitigation works on JEN feeders originating from Kalkallo zone substation (**KLO**). We did not include expenditure relating to this regulatory obligation in our initial proposal. We outline the reasons for the change in approach below.

3.3.1 Background

KLO is owned by AusNet Services (**AusNet**) and supplies three JEN HV feeders and four AusNet feeders. The KLO supply area includes a mix of greenfield urban development areas containing significant lengths of underground feeders—including new residential estates located in the Melbourne's north growth corridor—and undeveloped rural land.

Of JEN's three KLO feeders, two are almost entirely underground (with one short overhead section on feeder KLO13 only), and the other (KLO22) has a mix of overhead network and various small underground sections. All three feeders are located in a HBRA.

Due to the bushfire ignition risks associated with the feeders in the areas served by KLO, it is a prescribed zone substation for the purposes of section 120M of the ES Act. This means that all feeders originating from KLO must have the *required capacity* by 1 May 2023. As outlined in the section above, in practice, this effectively requires the installation of REFCL equipment[43] or the undergrounding of the feeder.

Additionally, the ES Regulations require JEN, as a major electricity company (**MEC**)[44] whose network contains feeders which originate from KLO, to specify in its Bushfire Mitigation Plan how it will ensure that these feeders will have the *required capacity*,[45] and how the *required capacity* will be demonstrated annually.[46] Energy Safe Victoria (**ESV**) has outlined its expectations in relation to assets with multiple ownership arrangements, such as KLO, and clarified that JEN must meet the obligations under the ES Regulations outlined above in respect of its KLO feeders.[47]

JEN and AusNet previously undertook a joint planning exercise[48] during 2019 (**joint planning study**) to consider preliminary options for the achievement of the *required capacity* on KLO's feeders, prior to the submission of initial regulatory proposals. As a result of this process, JEN prepared its initial proposal based on:

- the construction by AusNet of a new REFCL-protected Kalkallo North zone substation—and the movement of JEN's largely overhead KLO feeder (KLO22) to this new station—thereby providing the *required capacity* on this feeder[49]

[43] In Victoria to date, REFCL equipment has been installed within the zone substation site, providing protection to all feeders originating from the station. An alternate approach is to install the equipment on an individual feeder (referred to as a 'remote REFCL'), providing protection only to that feeder. In this configuration, the REFCL equipment is installed 'remote' from the zone substation, typically where the underground section of the feeder ends and the overhead section begins.

[44] MEC is a term in the ES Act which includes distribution network service providers.

[45] Electricity Safety (Bushfire Mitigation) Regulations 2013, reg. 7(1)(ha).

[46] Electricity Safety (Bushfire Mitigation) Regulations 2013, reg. 7(1)(hb).

[47] ESV, *ESV Position Paper: Multiple Ownership of Polyphase Electric Lines and Complying Substations*, 21 August 2020.

[48] JEN, *2021-26 Electricity Distribution Price Review Regulatory Proposal – Attachment 05-06*, 31 January 2020.

[49] Page 40 of AusNet's document AMS 20-12 (*Augmentation: AMS – Electricity Distribution Network*), submitted as part of its initial regulatory proposal on 31 January 2020, outlines AusNet's proposed approach in relation to Kalkallo and Kalkallo North zone substations.

- obtaining an exemption from the need to achieve the *required capacity* on JEN's two other KLO feeders (KLO12 and KLO13), noting that these are almost entirely underground.

In line with the two considerations above—and noting these would have satisfied our obligations as an MEC with only minimal expenditure on the KLO feeders—our initial proposal did not include any expenditure relating to JEN's bushfire mitigation duties for KLO.

3.3.2 Our revised proposal

Since the submission of our initial proposal, an exemption has been granted in relation to the achievement of the *required capacity* on fully underground feeders. Our revised proposal therefore includes minor expenditure to remove a 0.17 km overhead section of feeder KLO13, thus making this feeder fully underground. Following these works, we will not need to take any further action in relation to KLO12 or KLO13 to achieve compliance with the ES Act.

Since our joint planning study, AusNet has undertaken further detailed analysis and determined that the construction of a new REFCL-protected Kalkallo North zone substation is not possible due to technical limitations of the existing REFCL technology. JEN has engaged with AusNet, ESV and the Department of Energy, Land, Water and Planning (**DELWP**) in relation to KLO during 2020. Through this process, AusNet has indicated that it now intends to install 'remote REFCL' devices to provide the *required capacity* on AusNet's overhead KLO feeders. As a result, in the absence of REFCL equipment being installed within the KLO (or a new Kalkallo North) site by AusNet to provide protection to JEN's KLO22 feeder, JEN must take action to ensure our KLO feeders have the *required capacity*, hence enabling us to comply with the ES Regulations. We have continued to engage with AusNet, DELWP and ESV in relation to our approach to ensuring compliance on our KLO feeders, and ESV has acknowledged our approach.[50]

Our revised proposal, therefore, includes expenditure to install a remote REFCL device on the KLO22 feeder itself, in addition to feeder reconfiguration and hardening works necessary to ensure the safe and effective operation of the REFCL in accordance with JEN's obligations as a MEC.

When developing our forecast expenditure to ensure compliance on KLO22, we considered a range of alternative options, such as undergrounding the entire feeder which would alleviate the need for REFCL-protection.[51] Of the technically feasible options which would enable compliance, our analysis indicated that our remote REFCL approach would maximise net economic benefits for our customers. Relevantly, alternative solutions considered would involve significant customer supply reliability risks (meaning that we would likely be unable to meet customers' expectations that we maintain our network reliability levels over the long-term in this local area), technical challenges and deliverability risks (noting JEN must achieve compliance for KLO22 by May 2023). Attachment 04-05 provides further information on our proposed approach to compliance for our KLO feeders, while Attachment 04-06 details our cost estimate for these works.

We have also revised our forecast for our REFCL compliance operating expenditure step change to cover the operating expenditure associated with our revised KLO works, including annual fault testing requirements. This is described further in Attachment 05-01.

[50] ESV letter to JEN, *RE: Strategy to meeting bushfire mitigation regulations – KLO22*, 25 September 2020.

[51] Due to the existing exemptions made in October 2020 relating to underground assets.

4. DER integration expenditure

DER integration expenditure encompasses our Future Grid program, which is designed to support increased two-way flows and energy trading by customers in the future, and to further improve network utilisation and optimise future network investment decisions.[52] The main driver of this expenditure is the continued growth in penetration of DER on our network. Our DER integration expenditure forecast is designed to help us achieve the objective below.

> Efficiently minimise any constraints on grid exports from distributed energy resources to the extent possible

JEN welcomes the AER's conclusion that it is satisfied our forecast DER integration expenditure forms part of a total capital expenditure forecast that reasonably reflects the capital expenditure criteria,[53] and that our program represents a proportional step in responding to increasing DER penetration.[54] The draft decision acknowledged the pivotal role our customer engagement—and particularly our People's Panel's recommendations—played in the development of our Future Grid program, as well as support from Consumer Challenge Panel sub-panel 17 (**CCP17**).[55]

As discussed further below, the draft decision noted some concerns from stakeholders relating to the valuation of DER and the impact such valuations could have on the economic case for investment in our program.[56] Our revised capital expenditure forecast continues to include our Future Grid program, with an additional $2M to reflect some of the activities we have withdrawn from our operating expenditure step change.[57] We discuss the concerns raised in the draft decision and by stakeholders in further detail throughout the remainder of this section. Overall, we have maintained our Future Grid program in our revised proposal in light of:

- continued strong growth in DER penetration and the associated technical challenges this presents for the efficient operation of the network
- customer and stakeholder support for our program
- our proposed expenditure per customer on hosting capacity upgrades being lower than other Victorian Network Service Providers (**NSP**s)
- our analysis demonstrating that our proposed program provides a net benefit to customers at a wide range of potential DER values
- our Future Grid program representing a relatively small proportion (approximately 4 per cent) of our gross capital expenditure forecast.

Figure 4–1 and Table 4–1 compare our initial proposal, the AER's draft decision and our revised proposal DER integration expenditure forecasts.

[52] The capital expenditure discussed in this section is classified for Regulatory Information Notice reporting purposes as either augmentation or non-network ICT expenditure, however we have presented all Future Grid expenditures in this chapter exclusively to align with the categorisations used in the AER's draft decision.

[53] AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-23.

[54] AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-25.

[55] AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-24.

[56] AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, pp. 5-24 – 5-25.

[57] Refer to Attachment 05-01 to our revised proposal.

Figure 4–1: How our DER integration expenditure compares (FY22-26, $ June 2021, millions)

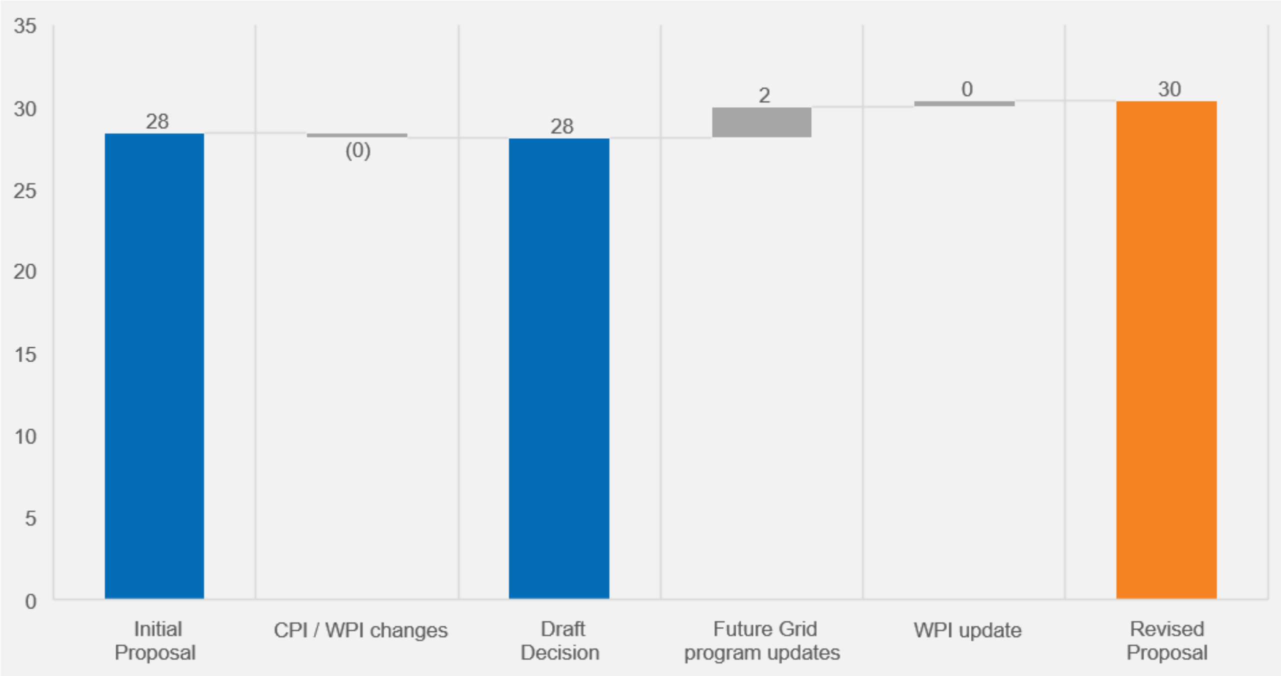


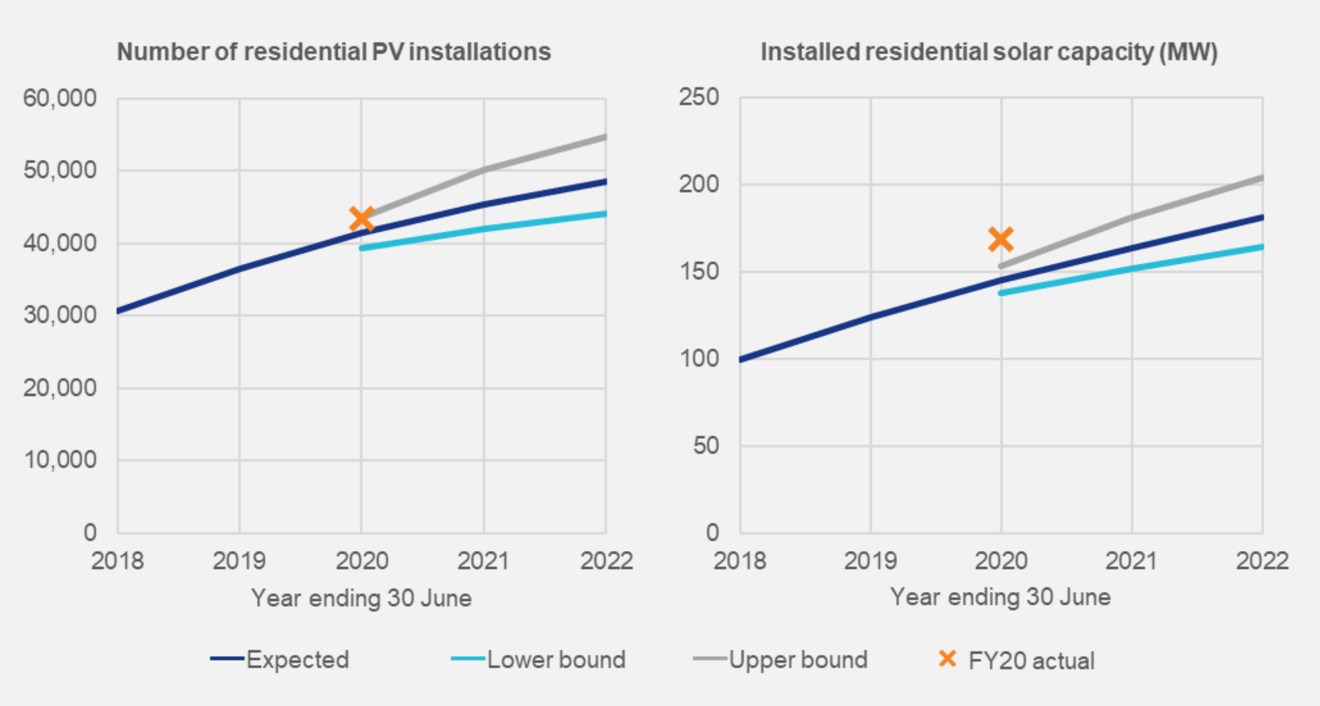
Table 4–1: Forecast DER integration expenditure (5 years, $ June 2021, millions)

DER integration expenditure	Initial Proposal	Draft Decision	Revised proposal
Foundation	14.0	13.9	15.9
Network wide control systems	6.1	6.0	6.1
Spatial hosting capacity network upgrades	8.4	8.3	8.4
Total	**28.5**	**28.2**	**30.4**

The current state of DER on our network

Since we developed our initial proposal during 2019, we have continued to see strong take-up of DER by customers across our network, with both the number of DER installations and the total rating of installed DER tracking the upper bounds of our projected take-up rates, as illustrated in Figure 4–2.

Figure 4–2: Growth in DER connected to our network



One key driver of growth in the medium term is the Victorian Government's significant support for the installation of small-scale DER under the Solar Homes program, which aims to enable the installation of solar panels, solar hot water systems or batteries in 700,000 homes by 2027-29. The Victorian Government recently reaffirmed its commitment to this program as part of its COVID-19 economic recovery plan, providing an additional 42,000 solar rebates over the next two years and expanding eligibility criteria to include small businesses.[58]

We note the draft decision's acknowledgement that while low voltage (**LV**) feeder constraints begin to occur at a DER penetration rate of 30 per cent, rates above this threshold can still be achieved.[59] We agree that the actual penetration rate at which constraints will occur is dependent on a number of factors, and that in practice some LV feeders may not experience constraints at 30 per cent penetration—and also that constraints can occur below 30 per cent penetration in some cases. Since submitting our initial proposal, we have undertaken some more detailed analysis to better understand the relationship between distribution substation DER penetration rates and the risk of customer DER curtailment (i.e. DER export constraints), explained further in Attachment 04-02. On balance, we consider that a penetration rate of 30 per cent represents an appropriate average threshold value for planning purposes.

Customer and stakeholder views

As noted in our initial proposal[60] and acknowledged in the draft decision,[61] the views and recommendations of our People's Panel were key to shaping our Future Grid program. Following the release of the draft decision, we re-engaged with our People's Panel to understand whether their views on our Future Grid program had changed. Through this engagement, we explained how some stakeholders had raised concerns about the valuation of DER benefits (explained further below) and how this could impact our assessment of whether our program was likely to provide benefits to customers. However, members remained supportive of our Future Grid program, with their comments emphasising continued strong expectations regarding customers' ability to export from DER into our network:

58 Victorian Minister for Energy, Environment and Climate Change, *Media release: Helping Victorians pay their power bills*, 17 November 2020.

59 AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-24.

60 JEN, *2021-26 Electricity Distribution Price Review Regulatory Proposal – Attachment 05-04*, 31 January 2020, p. 4.

61 AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-24.

> *'I will be adding solar panels, but probably not a battery, to my new house when it's built, and I want myself and others to be able to continue to benefit from exports.'*
>
> *'Because Solar is one of the best ways for families to reduce their energy costs and possibly delivery a green source back into the grid.'*

Further details of our engagement with the People's Panel are provided in Attachment 01-02.

The Victorian Minister for Energy, Environment and Climate Change has also communicated expectations that JEN should progress activities to enhance solar capacity and minimise barriers and constraints to the export of solar generation, as well as support for efficient investment in DER enablement.[62] We do note, however, that some stakeholders have raised concerns about the valuation of DER, and the impacts that different valuation methodologies may have on our program. We address these concerns further below.

Our Future Grid program

In line with the AER's draft decision, the continued strong uptake in DER on our network and the views of our customers and stakeholders, we have included our Future Grid program in our revised proposal. We have included an additional $2M in our DER integration capital expenditure forecast for the next regulatory period, in addition to making minor updates for real cost escalation. This additional expenditure reflects two of the activities we had previously included in our initial proposal's operating expenditure step change for Future Grid,[63] and which we have withdrawn from our revised proposal's operating expenditure forecast.[64] These activities—preparatory work to assist in the design of our new ICT capabilities, and the collection of the network data necessary to develop a LV network model—are key enablers of our Future Grid program.[65]

Tariff design and our Future Grid program

Several stakeholders suggested the need for NSPs to develop coordinated strategies for DER integration which consider interrelationships between expenditure, tariff design and demand management activities. These views were raised during the AER's consultation on our initial proposal[66] and during the CSIRO and CutlerMerz's Value of Distributed Energy Resources Methodology Study (**VaDER study**)[67], commissioned by the AER and Australian Renewable Energy Agency. We have considered this feedback when refining our Future Grid program for our revised proposal, and will continue to consider interactions between these areas on an ongoing basis.

In relation to tariff design, our Tariff Structure Statement[68] outlines our new default tariff for residential customers. This tariff is primarily designed to incentivise customer behaviour which may reduce network demand at peak times, with a secondary purpose of incentivising customer behaviour which may help address the challenges associated with growing DER penetration on our LV network. The new residential tariff is expected to provide some spill-over benefits which could potentially help mitigate some DER-related challenges, by incentivising customers to charge household batteries before our 3 pm peak window commences, thus making it more likely that their excess solar generation is used to charge the battery.

However, the extent to which these behavioural changes will materialise over the next regulatory period, and the extent of any near-term benefit they would provide to the network, is unclear—particularly given we expect that only around 12 per cent of our residential customers will be assigned to this tariff by the end of the next regulatory period. We therefore consider that the overall efficacy of this tariff in addressing DER penetration challenges within the next

62 Victorian Minister for Energy, Environment and Climate Change letter to Jemena Managing Director, 31 July 2020.

63 Described in section 3 of Attachment 06-05 to our initial proposal.

64 Refer to Attachment 05-01 to our revised proposal.

65 Note that operating expenditure we had previously forecast for incentive payments to customers for DER inverter setting updates is not included in our revised proposal capital or operating expenditure forecasts.

66 For example, CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021-26*, 10 June 2020.

67 CSIRO and CutlerMerz, *Value of Distributed Energy Resources: Methodology Study: Final Report*, October 2020, p. 56.

68 Attachment 12-01 to our revised proposal.

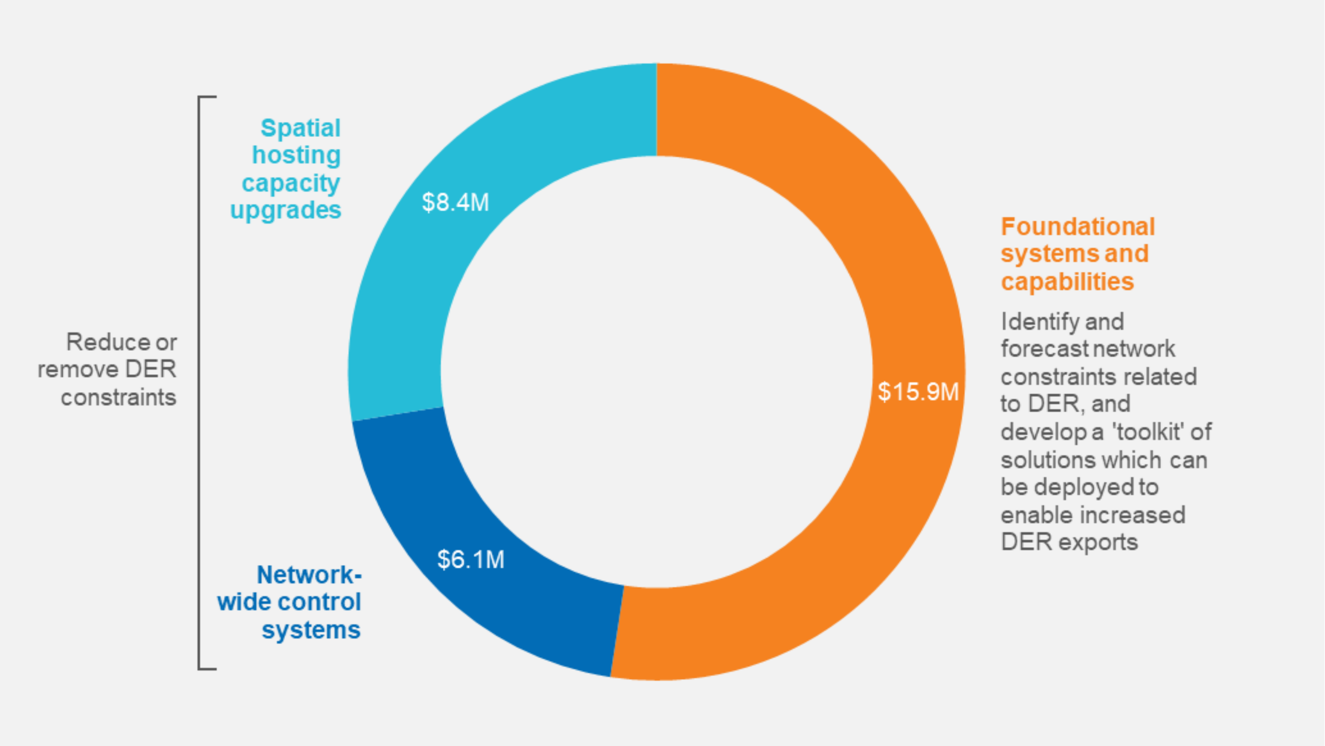
> regulatory period will be relatively low, and that it will not displace the need for DER integration expenditure or demand management activities.
>
> We do consider, however, that tariff-based mechanisms such as export charging may be able to have a material impact on the future DER integration challenges faced by NSPs—noting current prohibitions in the National Electricity Rules and the Victorian Government's position on export charging.

Importantly, our Future Grid program continues to comprise activities which can be classified into two separate groups based on their objectives:

1. **Developing foundational systems and capabilities**—developing the tools which will allow us to identify and forecast DER constraints on our network, and to assess the most efficient way of addressing (or in some cases, not addressing) these constraints
2. **Addressing (reducing or removing) DER constraints**—using the new capabilities enabled by the activities above, implementing network-wide control systems to provide dynamic export signals to DER and undertaking targeted investments to increase the network's hosting capacity for DER where efficient.

Figure 4–3 illustrates the composition of our Future Grid program in our revised proposal, showing that more than half of our expenditure relates to building foundational systems and capabilities. Our strong focus on these activities during the next regulatory period reflects a 'least-regrets' approach and is necessary to underpin the efficient integration of DER into our network over the long-term. Our Future Grid roadmap and the interrelationships between these two components are discussed further in Attachment 04-02.

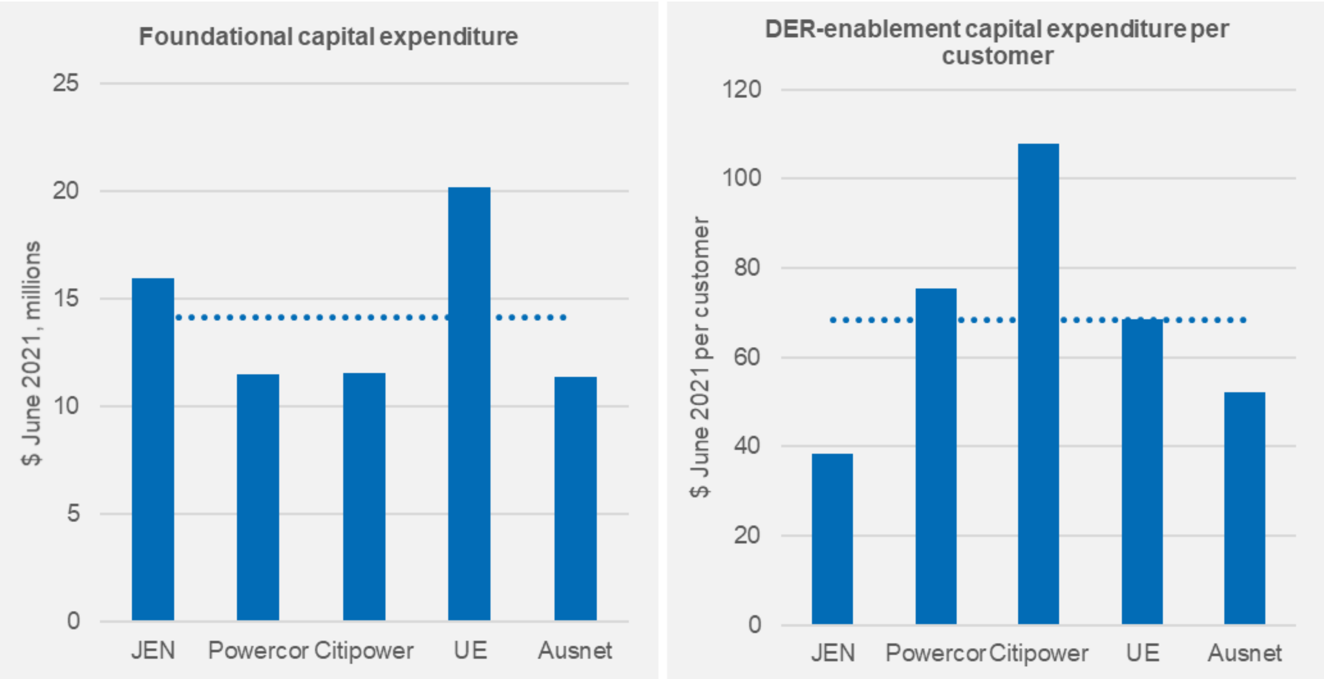
Figure 4–3: Composition of our revised proposal's Future Grid program (5 years, $ June 2021, millions)



In broad terms, expenditure on the foundational systems and capabilities required in response to growing DER penetration could generally be considered to be somewhat 'fixed' in relation to the size of a NSP's customer base. More relevant determinants of the amount of expenditure required to develop these necessary capabilities are likely to be factors such as the NSP's existing capabilities, systems and data—albeit that the measurement of such factors may be challenging. In contrast, expenditure designed to reduce or remove DER constraints, or increase the hosting capacity of the network, is more likely to be somewhat driven by 'variable' factors such as customer numbers or, importantly, DER penetration rates.

Noting these differences in cost drivers and the significant differences in network characteristics between Victorian NSPs, we consider that both components of our Future Grid program represent a relatively modest level of expenditure when compared to other NSPs' proposals. Figure 4–4 shows that JEN's revised proposal foundational expenditure is similar to the average amount of foundational expenditure proposed by other Victorian NSPs in their initial regulatory proposals. Additionally, on a per-customer basis (reflecting the more variable nature of this expenditure), our expenditure to address DER constraints is significantly lower than all other Victorian NSPs' initial regulatory proposals, noting that differences in DER penetration rates and other network characteristics are also likely to drive differences between NSPs' expenditures on these activities.

Figure 4–4: Comparing our Future Grid expenditure (5 years, $ June 2021)



Source: JEN analysis, based on AER draft decision capital expenditure models, AER draft decision capital expenditure attachments and DNSP price reset RIN responses.

Uncertainty around the valuation of DER benefits

In our initial proposal, we outlined our Future Grid program's cost-benefit analysis.[69] Consistent with best practice principles for network investment analysis, such as the broad framework outlined in the AER's Regulatory Investment Test for Distribution Guideline, our approach involved assessing multiple options relative to a counterfactual ('do nothing' option), to identify the option which maximises the net market benefits. This ensures that investments are in the long-term interests of customers.

The draft decision notes concerns from some stakeholders regarding the valuation of DER, including some which were raised broadly in relation to a number of NSPs as part of the VaDER study.[70] These concerns relate to the risk that the value assigned to DER exports in our Future Grid program's cost-benefit analysis may overstate the benefits of additional DER.

As highlighted throughout the VaDER study, there has been a range of methodologies employed by NSPs to value DER benefits when undertaking cost-benefit analysis for DER integration programs.[71] The final VaDER

69 Refer to Attachment 05-04 to our initial proposal.

70 AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-24.

71 CSIRO and CutlerMerz, *Value of Distributed Energy Resources: Methodology Study: Final Report*, October 2020, p. 56.

study report was published by the AER on 11 November 2020, and proposes methodologies to calculate the value of an increase in DER hosting capacity. The study proposes longhand and shorthand calculation methods which could be employed in various situations. The study recommends that the AER should develop guidance for NSPs on a number of matters relevant to DER integration cost-benefit analysis, including the practical application of the methodology proposed by the study, as well as commissioning the development of standard input assumptions for use by NSPs when applying the methodology.[72] The AER has stated that the study's findings and recommendations will be reviewed and considered as part of the AER's DER integration expenditure guideline, which is expected to be completed in 2021.[73]

Although the VaDER study proposes a methodology which could potentially result in a different value of DER to that which we used in our initial proposal's Future Grid cost-benefit analysis, we consider there are currently a number of barriers to its application, particularly within the timing constraints associated with the current price review process. For example, undertaking electricity market modelling in the VaDER Study's longhand method involves significant complexity, resources and time, noting also the current absence of the standardised input assumptions for use in such analysis recommended by the VaDER Study. Matters such as the thresholds used to determine whether longhand or shorthand approaches should be employed are also currently under consideration by the AER following receipt of the study's final report. We expect these matters will undergo public consultation during 2021 as the AER develops its DER integration expenditure guideline.

However, in response to stakeholders' views on this subject and recognising that there are a range of different DER values which could be employed to assess the benefits of DER integration expenditure, we have undertaken further sensitivity analysis on the parts of our program which relate to increases in hosting capacity. As discussed in the section above (see Figure 4–3), $14.5M of our Future Grid program capital expenditure during the next regulatory period relates to activities which will address DER constraints—this expenditure is targeted at increasing the amount of DER which our network can safely and efficiently accommodate. The broad methodology outlined in the VaDER study is designed to calculate the value of an increase in a network's DER hosting capacity,[74] therefore its use in cost-benefit analysis is only relevant to assess the potential benefits of activities (expenditure) which directly increase a network's hosting capacity.

In our initial proposal, we valued DER exports at 10 cents per kilowatt hour, reflecting the Essential Services Commission of Victoria's (**ESC**) draft proposed minimum single rate feed-in tariff for FY21. On 17 November 2020, the ESC published its draft decision on its review of FY22 minimum feed-in tariffs, which proposes to reduce the minimum single rate tariff to 7.1 cents per kilowatt hour.[75] The results of our sensitivity testing on our proposed hosting capacity expenditure are summarised in Figure 4–5, showing that our proposed investments to increase hosting capacity provide a higher net benefit than the counterfactual scenario at DER values above 3.2 cents per kilowatt hour. Of note given the uncertainty around DER valuation methodologies, this break-even value is significantly lower than the ESC's proposed FY22 minimum feed-in tariff, and significantly lower than the values used by other Victorian NSPs in their initial proposals.[76]

72 CSIRO and CutlerMerz, *Value of Distributed Energy Resources: Methodology Study: Final Report*, October 2020, p. 2.

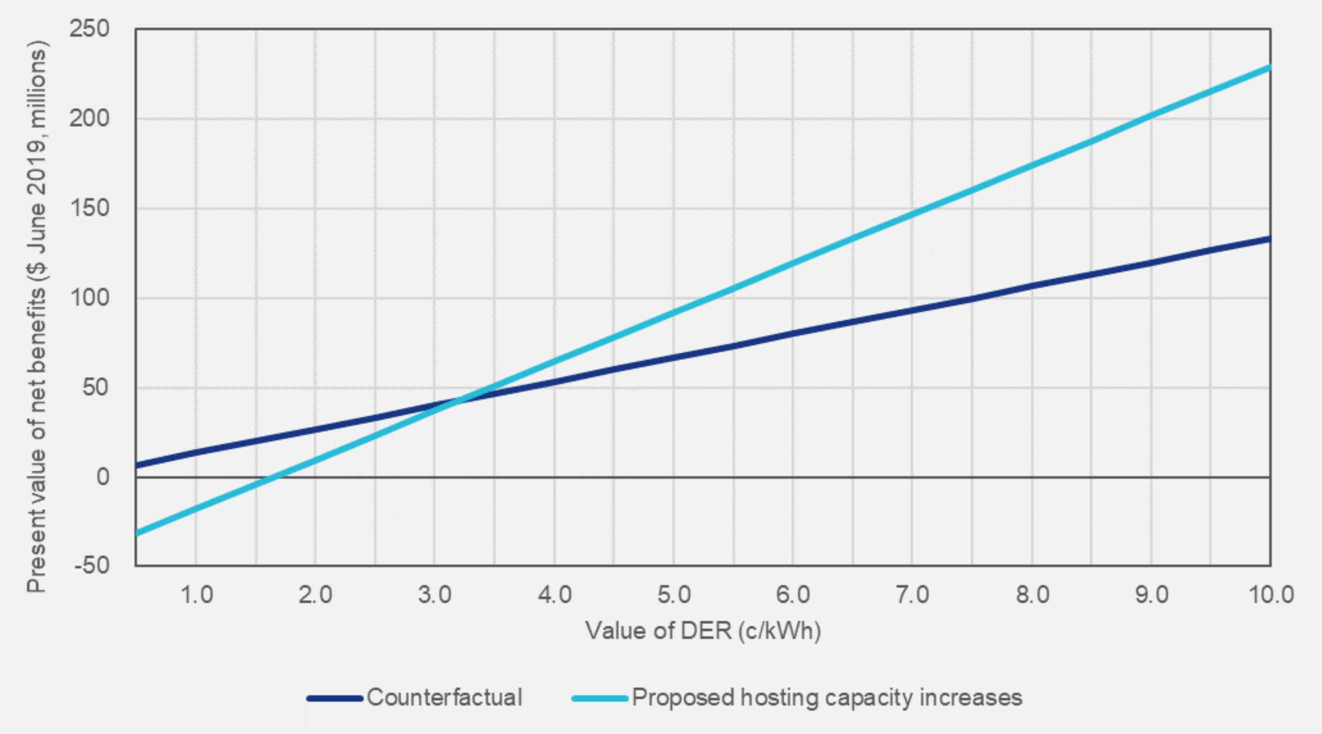
73 https://www.aer.gov.au/communication/aer-releases-value-of-distributed-energy-resources-report

74 CSIRO and CutlerMerz, *Value of Distributed Energy Resources: Methodology Study: Final Report*, October 2020, p. vi.

75 ESC, *Minimum electricity feed-in tariff to apply from 1 July 2021: Draft decision*, 17 November 2020.

76 CSIRO and CutlerMerz, *Value of Distributed Energy Resources: Methodology Study: Final Report*, October 2020, p. 1.

Figure 4–5: Hosting capacity increase NPV sensitivity to DER values



We consider that the significant range of DER values at which our hosting capacity expenditure provides a net market benefit, combined with the strengthening uptake of DER on our network, should provide stakeholders with confidence that this expenditure is prudent, efficient and in the long-term interests of our customers.

5. Non-network expenditure

We need to build, procure and replace assets that are used to support the operation of our network and delivery of standard control services to customers. Our non-network expenditure relates to four types of assets—information and communications technology (**ICT**), motor vehicles, property and other assets (such as tools, plant and other equipment).[77] We developed our non-network expenditure forecast around the objectives below, as set out in our initial proposal.[78]

> Meet customers' expectations that we should maintain our current levels of service reliability (including the frequency and length of network outages) at the most efficient cost over the long-term.
>
> Manage safety, environmental, physical security and cybersecurity risks to as low as practicable and comply with all applicable regulatory obligations at the most efficient cost over the long term.

JEN welcomes the AER's draft decision to accept our non-network expenditure, which found that it reasonably reflects the capital expenditure criteria.[79] The AER's draft decision also acknowledged the views of our stakeholders in relation to our forecast non-network capital expenditure, which was lower than our current period's expenditure and relatively low in comparison to other Victorian NSPs.[80]

In relation to ICT, the draft decision notes that JEN's proposed recurrent expenditure is well-placed relative to other Victorian NSPs, and that our proposed non-recurrent programs such as SAP migration, five-minute settlement and cyber security, are necessary to ensure the continued efficient functioning of our systems (and therefore the ongoing provision of services to customers) and compliance with regulatory obligations.

Additionally, by applying the AER's *Non-network ICT capex assessment approach* guidance note, the draft decision acknowledges and accounts for critical interrelationships between recurrent and non-recurrent expenditure across regulatory periods, including that the introduction of new or expanded systems in the current regulatory period (as non-recurrent expenditure) can drive an increase in recurrent expenditure in subsequent regulatory periods.

Our revised proposal non-network expenditure forecast mirrors the amounts from our initial proposal and the AER's draft decision, with only two changes, as outlined below.

The first change is to highlight our SAP migration program that formed part of our business case for a technical migration of our Advanced Metering Infrastructure (**AMI**) instance of SAP IS-U to the SAP S/4 HANA platform during the next regulatory period. This expenditure was omitted from our initial proposal's capital expenditure model. This project forms part of our original SAP migration strategy (developed in response to the upcoming end of support for our current SAP systems) submitted as part of our initial proposal. The AER acknowledged this project was excluded from our capital expenditure model in the draft decision, and stated that it would assess this as part of its final decision.[81] Our initial proposal's capital expenditure model therefore understated the cost of our full SAP migration program by $8.1M, and we have now corrected this error in our revised proposal capital expenditure model.

For completeness, we confirm that our strategic approach to SAP migration outlined in our SAP Migration Business Case[82] (and the associated information outlined in our SAP Migration IT Investment Brief for JEN[83]) provided as part of our initial proposal remains correct and relevant, and the program costs shown in the business

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77 Note that the values shown throughout this section exclude ICT expenditure which relates to DER integration. To align with the categorisations used in the AER's draft decision capital expenditure document, all DER integration expenditure is discussed in section 4.

78 JEN, *2021-26 Electricity Distribution Price Review Regulatory Proposal – Attachment 05-01*, 31 January 2020, p. 98.

79 AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-30.

80 AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-30.

81 AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, p. 5-34.

82 *JEN - RIN - Support - IT Business Case - SAP Migration - 20200131 - Public.*

83 *JEN - RIN - Support - IT Investment Brief - SAP Migration - 20200131 - Public.*

case's economic analysis do incorporate AMI IS-U. Appendix A of this document provides further information about our ERP architecture and AMI IS-U.

The second change included in our revised proposal's forecast non-network expenditure is a minor adjustment relating to real price escalation, consistent with changes to other areas of our revised proposal capital and operating expenditure forecasts.

Figure 5–1 and Table 5–1 compare our initial proposal, draft decision and revised proposal non-network expenditure forecasts.

Figure 5–1: How our non-network expenditure compares (5 years, $ June 2021, millions)

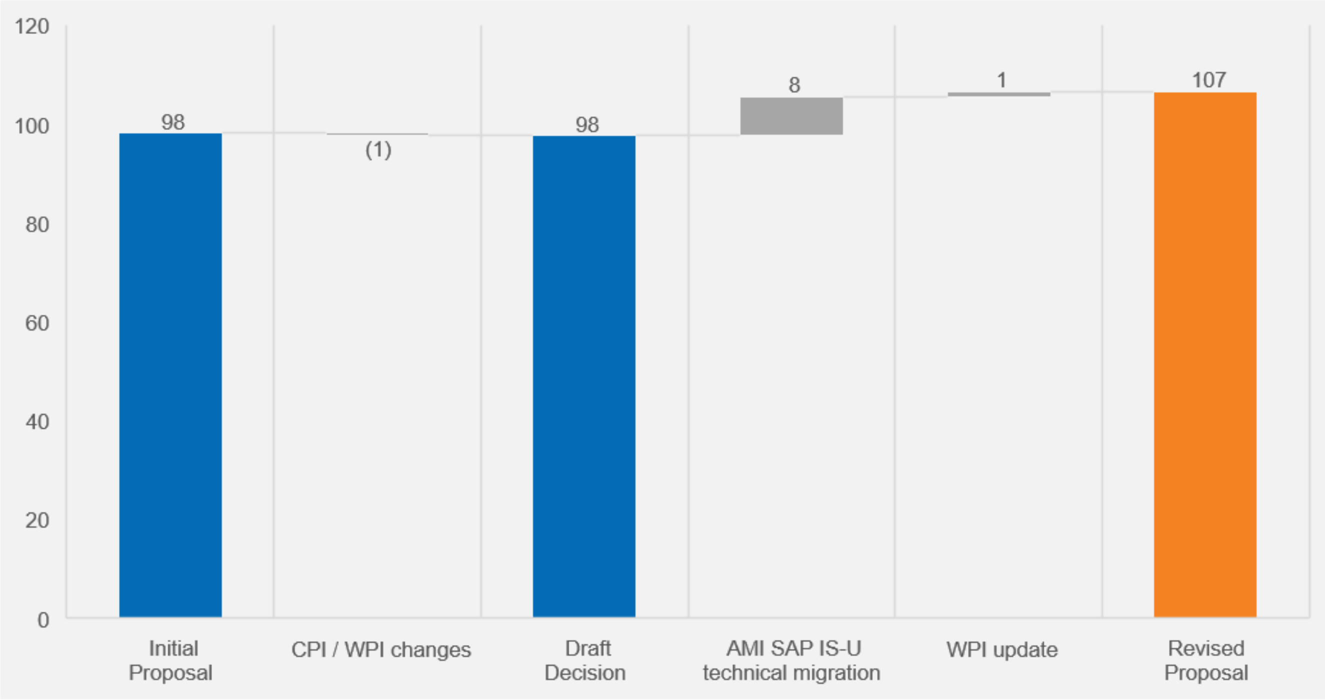

Table 5–1: Forecast non-network expenditure (5 years, $ June 2021, millions)

Non-network expenditure type	Initial Proposal	Draft Decision	Revised proposal
IT & communications[1]	80.1	79.5	88.3
Motor vehicles	9.9	9.9	9.9
Buildings and property	1.3	1.3	1.3
Other	7.0	7.0	7.0
Total	**98.2**	**97.7**	**106.6**

(1) Excluding DER integration expenditure.

6. Capitalised overheads

Our capital expenditure forecast includes an amount reflecting the capitalised portion of our overhead costs. This reflects the fact that some of the activities we carry out which are classified as overhead in nature are necessary to support the delivery of our capital works program.

The draft decision accepted our methodology for forecasting capitalised overheads, however made minor adjustments to reflect the draft decision's changes to the size of our direct capital expenditure and for real cost escalation.[84] Our revised proposal's forecast of capitalised overheads maintains our standard methodology and includes updates to reflect changes in our forecast direct expenditure and real price escalation.

[84] AER, *Draft decision: Jemena Distribution determination 2021 to 2026, Attachment 5 – Capital expenditure*, September 2020, pp. 5-36 – 5-37.

Appendix A
SAP IS-U (AMI) strategy overview

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A1. Overview

The objective of this appendix is to:

- present the current and planned high-level architecture of the Enterprise Resource Planning (**ERP**) system,
- explain why the current architecture was adopted, and
- show that the approach was efficient and prudent in the context of the investments made at the time of major changes.

The paper also explains why the future state architectural design is the most prudent and efficient approach, and in particular, hosting of the AMI IS-U instance separately.

The ERP is a critical IT system that is necessary for the safe, secure and reliable operation of JEN's energy networks.

A2. Background Information

The ERP covers Jemena's corporate business and its subsidiaries (**Jemena**), including JEN and Jemena Gas Networks (NSW) Ltd (**JGN**). The ERP, along with the wider IT environment it sits within, has evolved over time in response to industry, regulatory and corporate changes. With each change, Jemena has undertaken the most efficient path possible to maintain the functionality delivered through its ERP systems.

To the maximum extent possible, Jemena implements corporate wide systems. This approach to implementing and managing systems reduces cost for all of our customers, including JEN's customers, by averaging largely fixed costs across a larger pool of customers.

Jemena plans to complete a major upgrade of the current ERP during the next regulatory period to move to a platform with longer term support. This upgrade will involve shifting all ERP capabilities currently on the SAP ECC6 platform to the SAP S/4 HANA platform. Jemena's upgrade strategy is to complete a technical upgrade, with no investment in new/improved capabilities or transformation of the ERP/IT environment. This approach is termed a *technical upgrade* and is in keeping with SAP's scheduled withdrawal of support for the ECC6 platform shortly after Jemena's planned upgrade. For additional information on the proposed upgrade, refer to *JEN - RIN - Support - IT Business Case - SAP Migration - 20200131 - Confidential*.

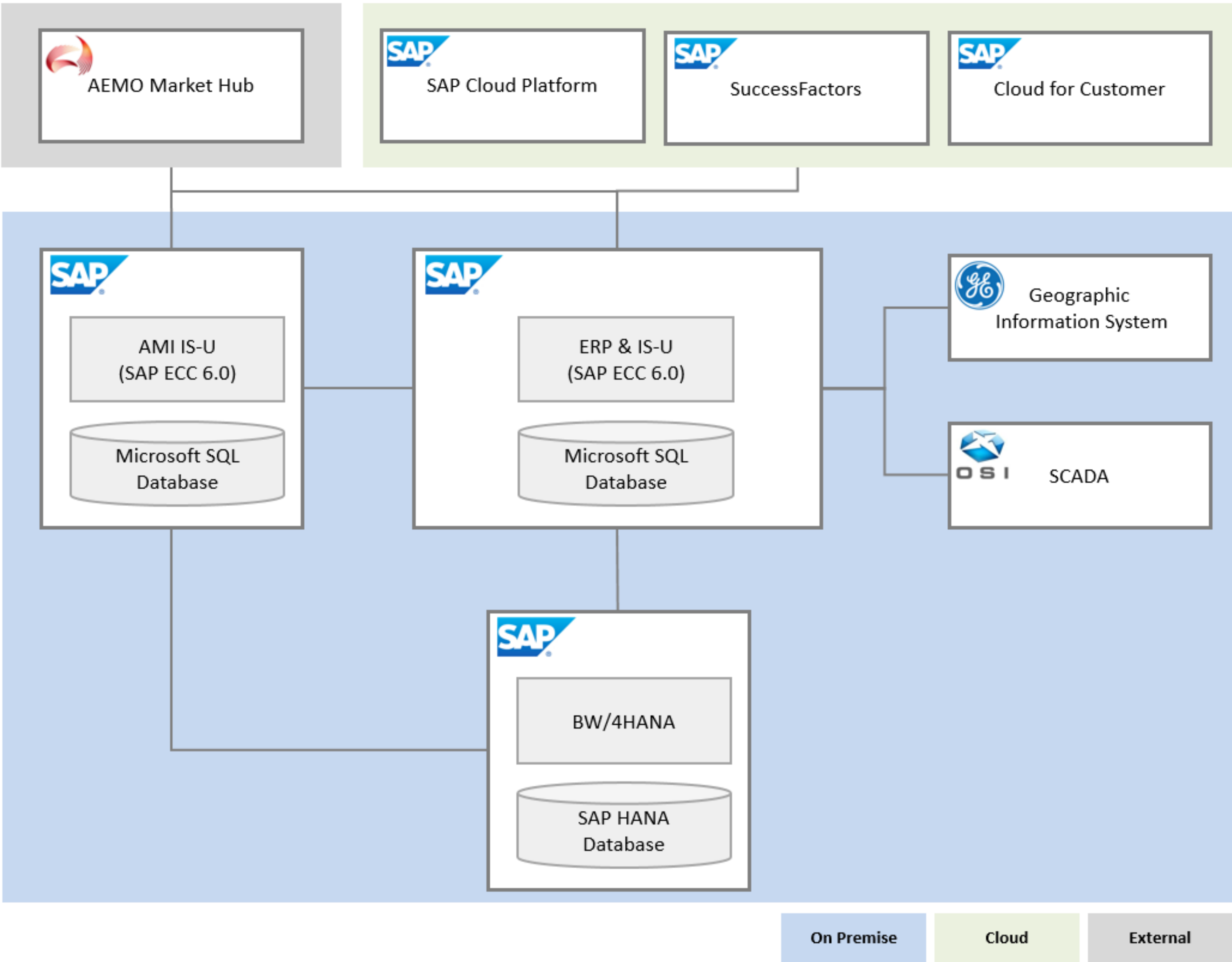
A3. ERP Architecture

Jemena's current ERP architecture has evolved as a result of historic industry, regulatory and corporate changes. Jemena currently operates two SAP environments, each built on separate databases.

1. The core ERP environment (**core ERP environment**) uses the SAP ECC6 ERP platform and includes SAP's Industry Specific – Utility (**IS-U**) package. This environment supports business operations for Jemena and its subsidiaries.
2. A separate AMI IS-U environment (**AMI IS-U environment**), which is used for JEN's AMI. This environment also uses the SAP ECC6 platform with IS-U, however, it does not include core ERP functions.

These two separate SAP environments can be considered separate modules within one system footprint as shown in the figures below.

A3.1 Current ERP Architecture



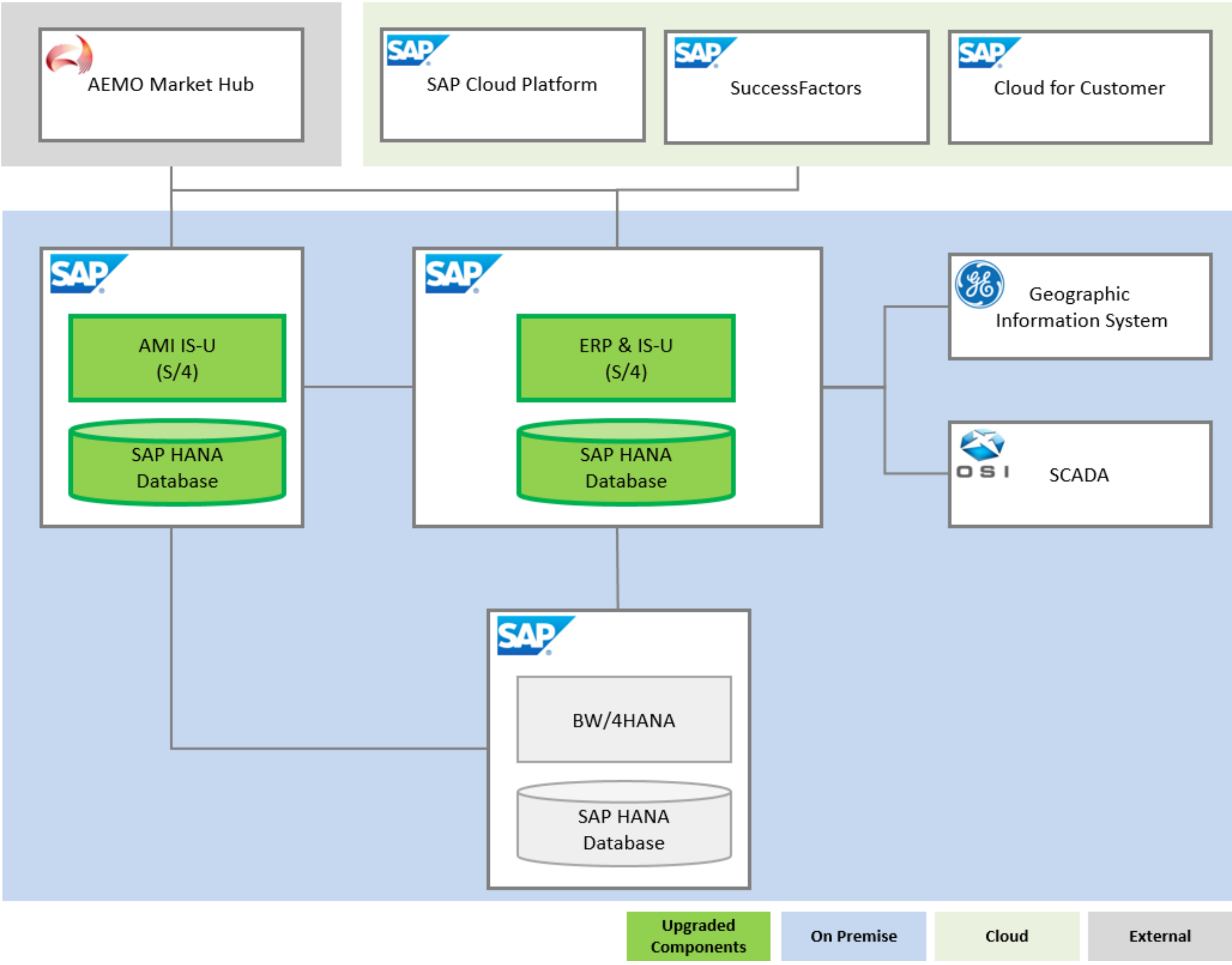
#	System / Component	Description
1	SAP ERP & IS-U	Jemena's core ERP platform supports the financial, metering and billing, human capital and asset management operations necessary for the efficient service and planning of our network Environment, health and management system Multi-resource scheduling system for planning and field force management
2	AMI IS-U	AMI IS-U manages JEN's billing processes, integrates with AEMO's market hub for publishing metering data for market settlement and communicates with JEN's AMI metering data collection IT system (Itron UIQ) and meter data management system.
3	BW/4 HANA	Jemena's analytics platform used for regulatory reporting and corporate dashboards
4	SAP HANA Database	In-memory, relational database management system developed SAP. HANA database for supports SAP's latest solutions such as S/4 HANA and BW/4 HANA
5	GIS	Stores spatial information of the Jemena's Network and integrates with SAP to support asset management and operations

#	System / Component	Description
6	SCADA	Jemena's SCADA system provides real-time monitoring and control for the electricity & gas networks
7	SAP Cloud Platform	SAP's cloud platform hosts Jemena applications - mWorkOrder, portal and the integration service for connecting our cloud solutions (SuccessFactors and C4C) to core ERP and AMI systems
8	SuccessFactors	Cloud-based HR solution for recruitment/onboarding, employee services, performance and learning management
9	Cloud for Customer (**C4C**)	Cloud-based Customer Relationship Management (**CRM**) system to manage customers and support tickets

A3.2 Planned Post-2025 ERP Architecture

Jemena plans to complete a major upgrade of the ERP during 2024 and 2025 to move to a platform with long term support. This upgrade will involve shifting all ERP capabilities currently on the SAP ECC6 platform to the SAP S/4 HANA platform. Jemena's upgrade strategy is to complete a technical upgrade, with no investment in new/improved capabilities or transformation of the ERP/IT environment. The planned upgrade will not change Jemena's ERP architecture.

SAP is scheduled to withdraw support for the ECC6 platform shortly after Jemena's planned upgrade.



System / Component	Description
SAP S/4HANA	S/4 is the successor to the SAP ERP 6.0, and it is optimised to run on a HANA database. S/4 provides a foundation for which Jemena can leverage for meeting current and future customer and business requirements.

A4. Review of Jemena's Current ERP Architecture

A4.1 History of Jemena's ERP Architecture

In 2010, as the Victorian AMI programme started, Jemena set up a stand-alone SAP ECC6 IS-U environment and supporting databases for the JEN AMI rollout. This environment is based around SAP's IS-U module, which is tailored for utility industry business functions such as meter reading, meter data management, scheduling, billing, invoicing, accounting, customer service, and integration to customer relations management. This environment does not contain a core ERP and associated functionality as it is only required to manage AMI related processes.

Jemena simultaneously developed an identical AMI environment for United Energy (**UE**), which is a related party of Jemena and in 2010 had an IT services contract with Jemena. By setting up the AMI with separate environments, Jemena was able to efficiently build the environments for both JEN and UE to minimise the total

IT cost component of the AMI rollout. As the *core ERP environment* for JEN and UE differed, building AMI into the existing *core ERP environment* of both businesses would have significantly increased the project cost. Additionally, at the time, both businesses were operating on legacy core ERP platforms that were due to be upgraded or replaced. Had the integration of the *AMI IS-U environment* into the *core ERP environment* taken place, the costs of those subsequent upgrades would have compounded.

Jemena implemented its current *core ERP environment* in 2012, upgrading two legacy ERPs that were inherited from Jemena's predecessor companies, Alinta and Agility, to the then latest SAP ECC6 core ERP. This approach was adopted, separate from the AMI system, to keep the conversion project costs down.

Jemena IT support for UE ceased in 2012. At this point, UE took responsibility for its own IT environments. Due to the architecture of separate *AMI IS-U environment*s, this change did not require any changes to the Jemena *AMI IS-U environment*.

In 2016 Jemena integrated JGN, then operating on its own separate legacy ERP environment, into the Jemena *core ERP environment* as part of a strategy to consolidate *core ERP environment*s.

Since 2016 Jemena has operated:

- a *core ERP environment* that is responsible for (i) all corporate functions, (ii) ERP processes for JEN and JGN and (iii) metering and billing for JGN, and
- a *AMI IS-U environment* for JEN (i) metering revenue & billing, (ii) plant maintenance, (iii) materials management and (iv) sales & distribution.

A4.2 Implications of Jemena's ERP Architecture

A4.2.1 Financial

From a financial perspective, the operating cost of the current *core ERP environment* and *AMI IS-U environment* architecture is identical to the cost of operating a single environment.

A4.2.1.1 Licencing

Jemena's SAP licence once-off and annual costs are not dependent on the number of ERP environments. Jemena's licence requirements are calculated by SAP and are based on the number of points of delivery (the count of customer connection points) and the number of users transacting in the landscape (the number of Jemena employees that require access to the ERP).

The separate instances are serviced by the same Jemena IT teams, and there are no staff costs that could be avoided if the environments were combined into a single environment.

A4.2.1.2 Maintenance

Annual costs, in the form of 'maintenance' fees, are a set percentage of the cumulative licence value. The rate used is negotiated by Jemena. As there are no additional licences for the AMI SAP instance, there is no additional maintenance cost for having two environments.

Jemena receives a substantial discount from standard rates due to the combined size of Jemena and its subsidiaries its and ability to negotiate as a single entity, providing a cost reduction relative to what Jemena's subsidiaries would face if each were to individually negotiate with SAP or any other ERP vendor.

A4.2.1.3 Infrastructure

The infrastructure requirements for two environments are similar to a single environment. The number of servers required would not change significantly because—as within a single environment—multiple servers are utilised based on the computation requirements. There would be no change to total storage requirements.

A4.2.2 Operational

From an operational perspective, the requirements of the current architecture are identical to the requirements of a single ERP environment for normal operations and more cost efficient when updates are required.

Jemena's IT department has one team managing the IS-U functions across both environments and one security and technical team managing the landscape. The number of staff is not affected by the presence of two environments.

All common interactions between the core ERP and *AMI IS-U environment*s are automated, so there is no operational impact from having two environments.

Some information is duplicated in the two environments (for example meta data), and therefore, some extra effort is required when information must be updated. For example, when tariffs are changed, both environments must be updated with the new information. However, this is a minor cost and is offset by the update process being simplified due to the separate environments.

If AMI were included in the core ERP, additional regression testing would be required as changes for AMI would potentially affect the JGN billing and metering functions (and vice-versa). These could cause customer impacts for both JEN and JGN customers when changes are made to the other network's settings in the ERP environment. This is because SAP shares objects between different functions and, although in most cases the risk of unwanted changes to other parts of the core ERP are unlikely, due to the criticality of the systems regression testing is required.

Updates to the separated *AMI IS-U environment* are straightforward as there is no need to regression test, for example, potential impacts on JGN metering and billing systems. This results in the current architecture being more efficient than a single environment.

A5. Jemena ERP Strategy

Jemena plans to complete a major upgrade of all ERP environments during 2024 and 2025 to move to a platform with long term support. This upgrade will involve shifting all ERP capabilities currently on SAP ECC6 platforms to SAP S/4 HANA platforms.

Jemena has undertaken a high-level review of the ERP architecture as part of the planning for the upgrade to a long-term supported ERP platform. This included considering rationalisation of the current two ERP IS-U instances into a single instance.

Jemena concluded (for the reasons discussed in the sections below) that rationalisation of the two environments into a single environment is not prudent as there are significant risks with no clear benefits. Jemena's preferred strategy is to upgrade and retain two separate ERP instances. This approach has several benefits, including:

- Shifting AMI into the *core ERP environment* risks locking JEN into using SAP for AMI metering and billing functions, whereas a separate environment provides more options for transitioning to alternative vendors if/when a better product becomes available
- Separate environments reduce the amount of regression testing for routine changes to the ERP environment and minor upgrades and updates of ERP software

- Separate environments reduce the complexity of and regression testing requirements for major ERP software upgrades, such as the planned upgrade to SAP S/4 HANA.

No additional costs will be incurred for rationalising the ERP environments, reducing total costs for Jemena and to Jemena's regulated customers.

A5.1 Jemena ERP Strategy – options summary

In summary, the approach to the technical upgrade of the *AMI IS-U environment* is characterised as a trade-off between:

1. Maintaining a separate AMI IS-U environment, or
2. Rationalising the AMI IS-U environment into the core ERP environment.

A5.1.1 Maintaining a separate AMI IS-U environment

The costs for Maintaining a separate *AMI IS-U environment* are outlined in the SAP Migration business case[85] and are expected to be $8.1M ($2021). The majority of this cost is for a technical upgrade to a newer SAP platform with long term support.

Jemena has not received any updated quotes for the upgrade since the business case was prepared. Updated quotes will be obtained closer to the planned technical upgrade, which is scheduled to begin in 2024.

A5.1.2 Rationalising the AMI IS-U environment into the core ERP environment.

The alternate option is to rationalise the AMI IS-U environment into the core ERP environment. The rationalisation would occur prior to the SAP upgrade because to do a conversion on both environments and a merge after would be more costly and less efficient.

Given Jemena's current architecture, the marginal activities involved in rationalising two SAP environments into one and the cost / benefits of each include:

- Conduct a detailed feasibility study to determine how the rationalisation will be undertaken
- Make necessary changes to the AMI IS-U environment to enable the rationalisation
- Make necessary changes to the core ERP environment to enable the rationalisation, in particular the core ERP IS-U module used for JGN metering and billing which will be most impacted function of the core ERP
- Complete the rationalisation and extensive regression testing

The marginal costs for this option include:

- Once off activity of converting two instances into one
- Ongoing increases in regression testing for updates due to the increased frequency (more modules and functions in the environment, each with their own periodic update requirements) and complexity of testing (due to more functions that may be affected by a change)

The marginal benefits for this option include:

- Ongoing reduction in effort when updating meta data

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A5.1.2.1 Once off activities

The once off activities for this option are the rationalising of the SAP systems and the technical upgrade of the former AMI IS-U functions in the rationalised ERP platform. The once off rationalisation cost is additional to the cost of a technical upgrade of a separate *AMI IS-U environment.* This is because the upgrade cost mostly covers regression testing of the upgrade on the functions provided by AMI IS-U and is not avoided by shifting the functions into a shared ERP environment.

A5.1.2.2 Ongoing activities

The ongoing costs are expected to exceed the ongoing benefits. There are no or negligible cost savings from the main ongoing costs of licencing, maintenance, and infrastructure.