



# Jemena Electricity Networks (Vic) Ltd

## 2021-26 Electricity Distribution Price Review Regulatory Proposal

Attachment 05-02

Capital expenditure for the 2016-20 regulatory period



## Table of contents

Abbreviations .....	iii
Overview .....	iv
1. Replacement expenditure .....	1
2. Connections.....	5
3. Augmentation .....	7
4. Non-network.....	9
5. Capitalised overheads .....	12

## List of tables

Table OV–1: Summary of current period capital expenditure against allowance (real June 2021, \$M).....	v
--	---

## List of figures

Figure OV–1: Summary of current period capital expenditure against allowance (real June 2021, \$M).....	iv
Figure OV–2: Current period capital expenditure against allowance by category .....	v
Figure OV–3: DNSP capital multilateral partial factor productivity indexes, 2006-18 .....	vi
Figure 1–1: Replacement expenditure for the current regulatory period (real June 2021, \$M) .....	1
Figure 2–1: Connections expenditure for the current regulatory period (real June 2021, \$M) .....	5
Figure 3–1: Augmentation expenditure for the current regulatory period (real June 2021, \$M) .....	7
Figure 4–1: Non-network expenditure for the current regulatory period (real June 2021, \$M).....	9
Figure 4–2: Non-network IT expenditure for the current regulatory period (real June 2021, \$M).....	10

## Abbreviations

ABC	Aerial Bundled Cable
Actual expenditure	JEN's actual capital expenditure for the years CY16-18 and its estimated capital expenditure for the years CY19-20
AER	Australian Energy Regulator
CESS	Capital Efficiency Sharing Scheme
Current regulatory period	The period 1 January 2016 to 31 December 2020
FE	Footscray East zone substation
FW	Footscray West zone substation
JEN	Jemena Electricity Networks (Vic) Ltd
Next regulatory period	The regulatory period 1 July 2021 to 30 June 2026
Regulatory allowance	The capital expenditure forecast contained in the AER's distribution determination for JEN for the current regulatory period
SCS	Standard Control Services

## Overview

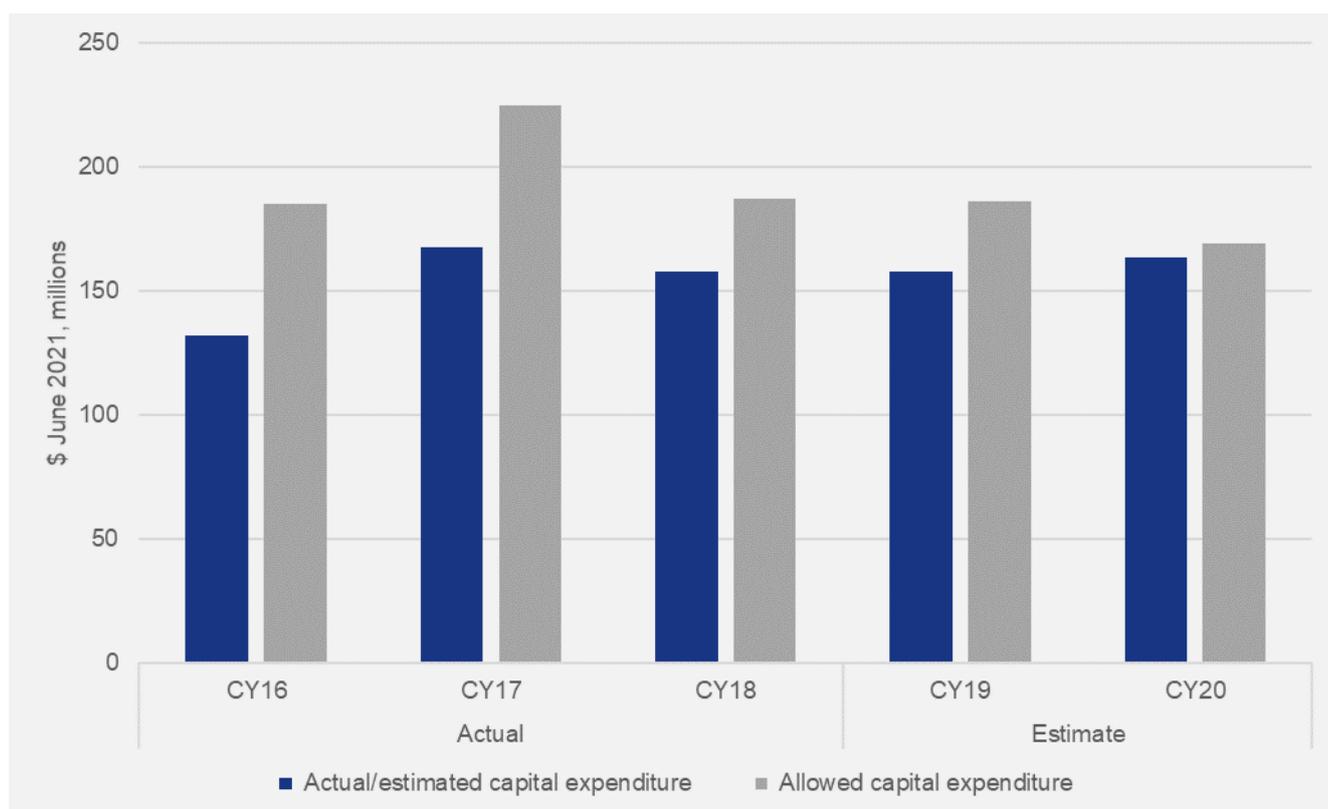
The purpose of this document is to demonstrate that Jemena Electricity Networks (Vic) Ltd's (**JEN**) capital expenditure during the CY16-20 regulatory period (**current regulatory period**) has been prudent and efficient, with investments undertaken consistent with good industry practice and in the long-term interests of our customers.

This document presents comparisons between the capital expenditure forecast contained in the Australian Energy Regulator's (**AER**) distribution determination for JEN's current regulatory period<sup>1</sup> (referred to as our **regulatory allowance**) against our actual and estimated capital expenditure<sup>2</sup> (referred to as our **actual expenditure**) for the current regulatory period adjusted for the time value of money for ease of comparison. This document covers gross capital expenditure for standard control services (**SCS**) only. Attachment 07-04 contains details of JEN's capital contributions and asset disposals during the current regulatory period for the purposes of determining our Regulatory Asset Base.

Unless otherwise stated, all dollars shown in this report are presented on a June 2021 basis and, in chapters 1 to 4, are presented as exclusive of overheads.

Overall for the current regulatory period, we expect to underspend against our regulatory allowance of \$952M by approximately 18 per cent. The figures below show our allowance and estimated capital expenditure for the current regulatory period, and Table OV-1 sets out our allowed and estimated expenditure by expenditure category. Variances contributing to this overall result are explained by expenditure category in each chapter below.

**Figure OV-1: Summary of current period capital expenditure against allowance (\$ June 2021, millions)**



(1) Gross SCS capital expenditure

<sup>1</sup> As set out in AER, *Final Decision: Jemena distribution determination 2016 to 2020, Attachment 6 – Capital expenditure*, May 2016.

<sup>2</sup> Comprised of our actual capital expenditure for CY16, CY17 and CY18 (as per our submitted Regulatory Information Notice responses for those years) and an estimate of our expected actual capital expenditure for CY19 and CY20.

Figure OV-2: Current period capital expenditure against allowance by category

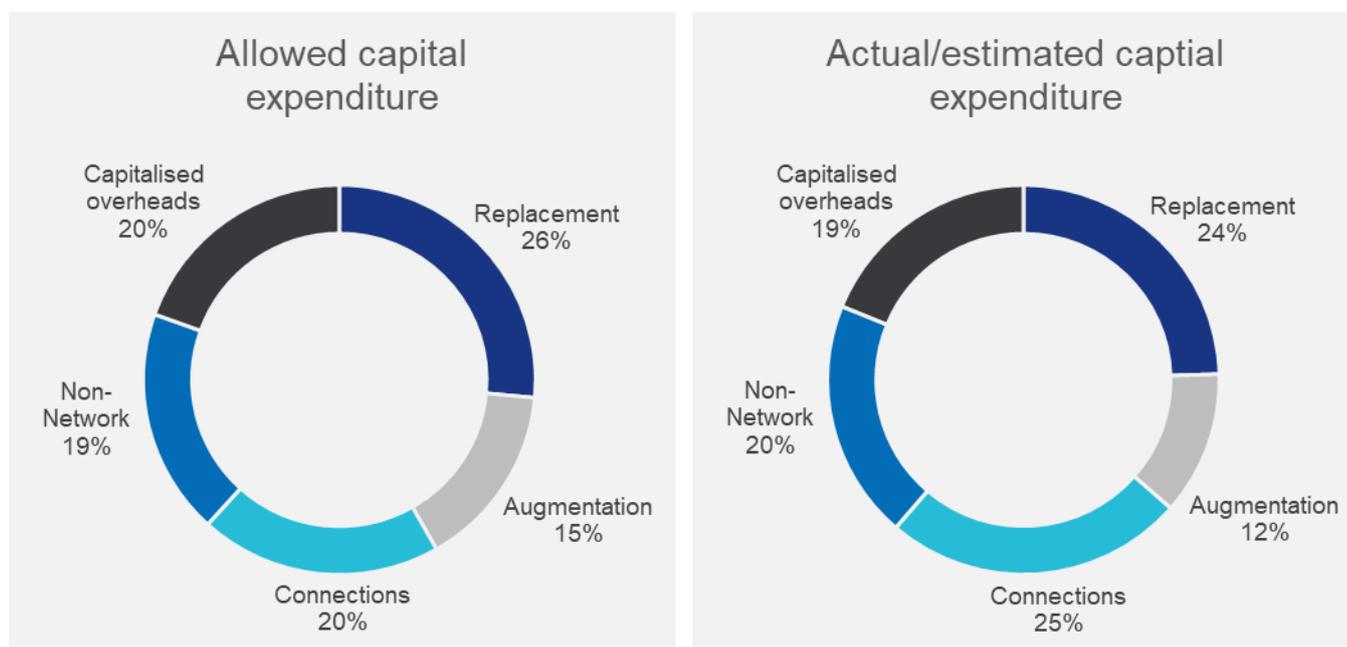


Table OV-1: Summary of current period capital expenditure against allowance (\$ June 2021, millions)

Expenditure category	Allowance	Actual/Estimate	Variance to allowance (%)
Replacement	251.8	191.0	-24%
Connections	189.9	193.2	2%
Augmentation	145.6	92.8	-36%
Non-network	178.4	154.7	-13%
Capitalised overheads	186.0	146.6	-21%
<b>Total</b>	<b>951.7</b>	<b>778.2</b>	<b>-18%</b>

We must make efficient investment decisions, consistent with the long-term interests of our customers, based on the best information available at the time of that investment decision, even if this information is different to that which formed the basis of our capital expenditure allowance. This can mean variances arise between our allowance and estimated capital expenditure for the current regulatory period, particularly at a category level. When we investigate the drivers of these variances, we see they are primarily driven by adjustments we have made to our capital works program in response to unforeseen circumstances.

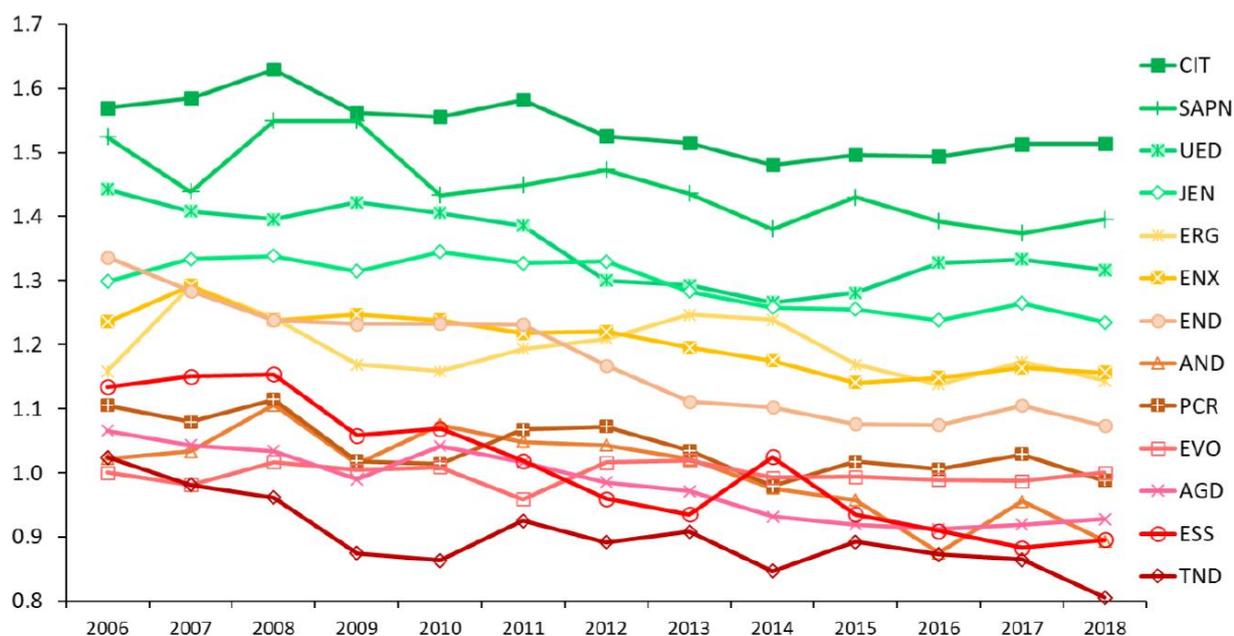
A key attribute of the regulatory framework in which we operate is the incentives we face as a distribution network service provider to continuously optimise the efficiency of our capital expenditure—in particular, we are incentivised to ensure we do not invest in our network unnecessarily. A range of exogenous factors which influence capital investment have changed since we developed our capital expenditure forecast for the current regulatory period (which formed the basis of our capital expenditure allowance). Conversely, we must continue to invest to ensure we meet our all regulatory obligations (including obligations to maintain the safety and reliability of the network and obligations to connect and meet new customer demand) and our customers' service expectations, even if that requires investing in a capital project which was unforeseen at the time our allowance was developed.

Additionally, the Capital Efficiency Sharing Scheme (**CESS**) provides us with further incentives to efficiently optimise our capital expenditure, while still ensuring we meet our customers' expectations. As set out in Attachment 07-05 to our regulatory proposal, based on our capital expenditure underspend against allowance during the current regulatory period, we expect to earn a CESS revenue reward during the next regulatory period. However, as explained throughout this document, in some instances, our capital expenditure underspend relates to material projects which we have deferred and then re-proposed in the next regulatory period. In cases of these material projects, we have made negative adjustments to our CESS reward, consistent with the approach set out in the AER's Capital Expenditure Incentive Guideline for Electricity Network Service Providers.<sup>3</sup>

Despite underspending against our allowance for the current regulatory period, we have continued to deliver the services that our customers expect. Indeed, during the current period, our network reliability has remained strong as we continue to respond to the incentives provided by the Service Target Performance Incentive Scheme.

We have continued to apply our expenditure governance processes—underpinned by our ISO 55001-accredited asset management system—to prudently and efficiently plan, prioritise and deliver on capital investment decisions. The efficiency of our capital expenditure is reflected in JEN's strong performance in the capital multilateral partial factor productivity index calculated by the AER in its annual benchmarking report. JEN ranks fourth out of 13 distribution network service providers on this index in the AER's 2019 report<sup>4</sup> and has been ranked fourth since 2013, as illustrated in Figure OV-3.

**Figure OV-3: DNSP capital multilateral partial factor productivity indexes, 2006-18**



Source: Economic Insights, AER analysis.

Throughout this period, our customers (and stakeholders throughout the broader energy market) have continued to emphasise the importance of energy affordability. We are mindful that the capital investment decisions we make today will impact our customers for decades into the future. We also understand that our customers expect us to continually optimise the investments we make to deliver their services and to keep looking for ways to deliver our capital projects more efficiently. We have been mindful of these customer priorities and feedback when making our investment decisions in this regulatory period, and also when developing our capital expenditure forecast for the 2021-26 regulatory period (**next regulatory period**).

<sup>3</sup> AER, *Better Regulation: Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, p. 9.

<sup>4</sup> AER, *Annual benchmarking report: Distribution network service providers*, November 2019.

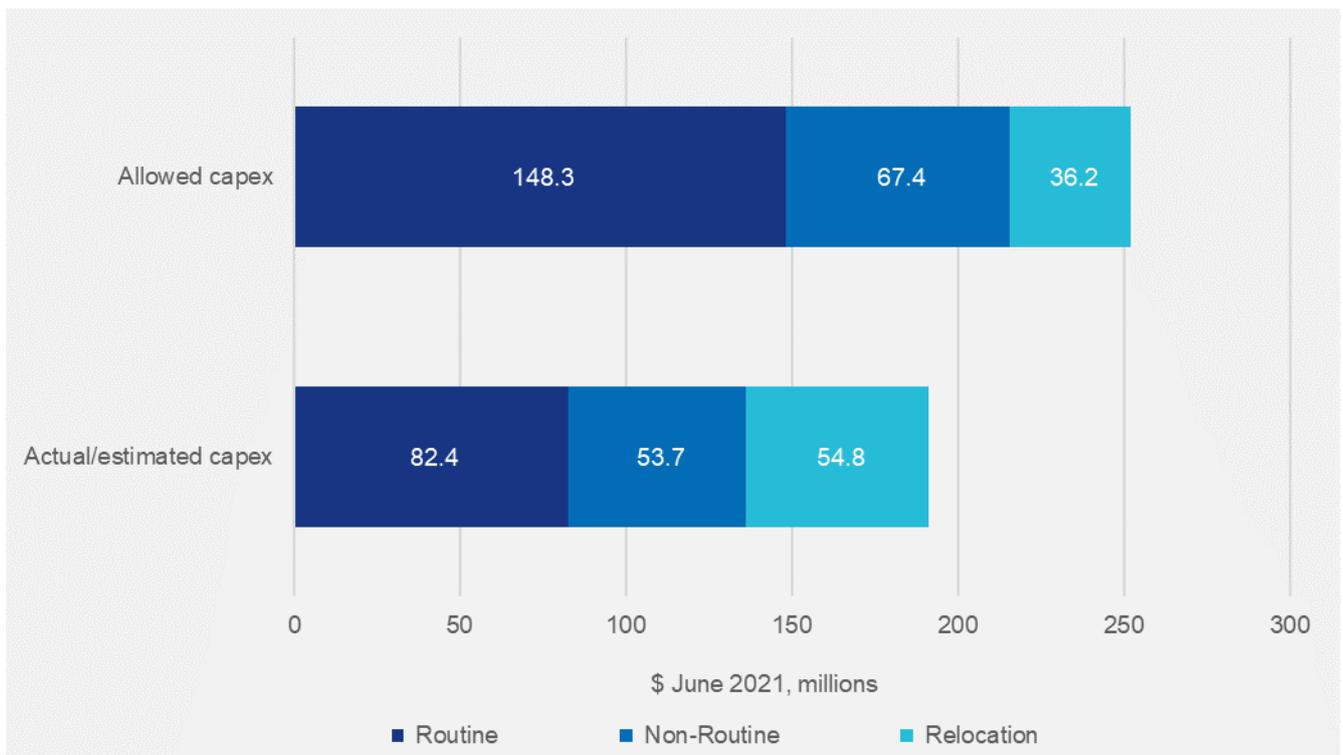
## 1. Replacement expenditure

The main purpose of replacement expenditure is to replace or refurbish parts of the existing network which have reached the end of their economic lives with their modern equivalents. Replacement expenditure is generally required so that we can continue to maintain our current levels of network service, consistent with our customers' expectations. Replacement expenditure can be classified into three broad categories, each of which has different characteristics, drivers and forecasting approach:

- Routine replacement activities – the replacement of relatively high volume, low-value assets, for which forecasts are usually developed at a program level. The assets we have included in this category are largely those in the modelled expenditure categories in the AER's repex modelling.
- Non-routine replacement activities – the replacement of low volume, high-value assets. It includes some categories of zone substation transformers and switchgear and is generally forecast on an asset-specific, case-by-case basis.
- Customer-driven replacement activities – the replacement of assets, or expenditure to rearrange or modify network assets, at the request of a third party. This category of costs most commonly relates to requests from government authorities that we relocate our assets to allow for the construction of public infrastructure such as road or rail projects. This category also includes expenditure to repair damage to our assets caused by unidentifiable third parties.

In aggregate, we estimate that our total replacement expenditure for the current regulatory period will be \$191M. Our estimated replacement expenditure period is 24 per cent lower than our allowance for this category over the five year period. Figure 1–1 shows the composition of our allowed and actual replacement expenditure classified into the categories listed above.

**Figure 1–1: Replacement expenditure for the current regulatory period (\$ June 2021, millions)**



The key drivers for our underspend in replacement expenditure are discussed in the sections below.

## Routine replacement activities

For routine replacement activities, we estimate that we will underspend our allowance by approximately \$66M (44 per cent) for the current regulatory period. This underspend is largely attributed to two key factors—lower than forecast activity volumes and the achievement of delivery and scope efficiencies.

A key reason for our underspend on routine replacement is that we undertook fewer routine replacements of assets such as poles. Before analysing volume variances between our allowed and actual expenditure forecasts, it is first informative to consider the methodology we used to develop our routine replacement expenditure forecast, which forms the basis of our allowance. The forecast routine replacement expenditure which we proposed for the current regulatory period largely reflected the predicted replacement expenditure output by the AER's Repex Model, applying the AER's preferred methodology at the time of the last regulatory determination.<sup>5</sup> This was the first time the Repex Model had been used in a distribution determination for JEN and was also relatively early in the life of the Repex Model's development.

In practice, as outlined in our Asset Class Strategies, we only replace assets when an assessment of their condition demonstrates that they are at the end of their economic life. For assets such as poles, this is based on information we gather during our pole inspection program, through which poles deemed unserviceable are flagged in our asset information systems for reinforcement or replacement. We always make decisions on asset replacement using the best available information at the time of an investment decision. During the current regulatory period, our condition assessments of key categories of assets—such as poles or conductors—have indicated that the condition of these assets is, in aggregate, largely better than we had projected when developing our previous routine replacement activity forecast. Accordingly, fewer numbers of these key assets have required replacement during the current regulatory period, and we have therefore been able to reduce our expenditure (relative to our original forecast) in these areas without materially increasing the risk profile associated with these assets. Although network performance data can be influenced by factors such as weather conditions, the better-than-projected condition of these assets is evident through JEN's strong network reliability performance in the last three years, despite this reduction in routine replacement activities.

We note that since the time of making our previous regulatory determination, the AER has continued to develop and refine the Repex Model and its application approach. Most recently, the AER published an issues paper which explained a key development in its approach to using comparative scenario analysis when applying the Repex Model in upcoming regulatory determinations:

*Our current repex model approach produces repex forecasts for four scenarios. Previous distribution determinations where we have used the repex model have primarily focused on a 'historical scenario'. This scenario forecasts a distributor's expected repex and replacement volumes based on its historical unit costs and asset replacement practices (which are used to derive expected asset replacement lives).*

*Our refined comparative analysis repex modelling approach builds on this previous analysis and introduces the historical performances of other distributors in the NEM and compares these with a distributor's repex forecast.<sup>6</sup>*

Under the AER's modelling approach, the modelled scenario which uses a DNSP's historic unit costs and historic asset lives will always produce a higher result than scenarios which use either comparative (benchmark) unit costs or asset lives. Importantly, the AER's stated approach to applying the Repex Model in JEN's upcoming regulatory determination will be to set the thresholds at a level equal to a modelled scenario using either benchmark asset lives or unit costs. This is a key change in the approach used to develop our routine replacement expenditure forecast for the current regulatory period, where our predicted expenditure was based on our historical unit costs and asset lives. We, therefore, consider that the application of the updated Repex Modelling approach is likely to better align to our forecast routine replacement volumes for JEN's next regulatory period.

<sup>5</sup> Note that replacement expenditure on the pole top structure, SCADA and network control and Other asset categories was unmodelled in this analysis.

<sup>6</sup> AER, *Issues paper: AER review of repex modelling assumptions*, August 2019, p. 9.

Additionally, our underspend on routine replacement expenditure can also be partly attributed to other factors, including delivery and scope efficiencies we have achieved during the current regulatory period:

- **Continued refinement of work scheduling to leverage asset replacement opportunities.** We continually seek to refine the way we plan and schedule routine and non-routine works on our network to ensure optimal efficiency in the delivery of these works. In 2016 and 2017, this involved us modifying our policies and work instructions to require crews to perform a search in our Geographic Information System to identify any open job notifications within a 100 meter radius of a scheduled asset replacement job and to complete the works required to close those notifications. Specifically for LV overhead services, we also modified our policies to ensure that all services of a non-preferred type<sup>7</sup> connected to a pole are replaced with a preferred type when work is performed on the pole. We also now provide business cases for projects one year in advance to our services and projects team or contractors, to minimise the risk of incurring higher expenditure by needing to complete a job in a short space of time.
- **More accurate asset condition information.** During the current regulatory period, we adopted more sophisticated asset inspection techniques which include the use of high-resolution cameras to undertake ground-level inspections of pole top structures. Compared with our previous practice of undertaking visual inspections from the ground, this has allowed our inspectors to make more accurate assessments of the actual condition of individual assets, which then allows us to better predict the time an asset is likely to fail, therefore, allowing us to replace some assets later in their lives, effectively deferring some routine replacement expenditure.
- **Removal of cross-arms due to installation of aerial bundled cable (ABC).** During the current regulatory period, we instituted a policy of opportunistically replacing sections of bare overhead conductor with ABC if multiple cross-arms on that section were at the end of their technical lives, thus alleviating the need to replace those cross-arms.
- **Fewer opportunities for overhead conductor replacement.** We often take the opportunity to replace LV overhead conductors at the same time as their distribution substation is replaced or augmented. Lower than forecast demand growth in some areas of the network resulted in the need to augment fewer distribution substations (as explained in section 3), therefore providing fewer opportunities to replace conductors.

### Non-routine replacement activities

For non-routine replacement activities, we estimate that we will have an underspend of approximately \$14M (20 per cent) for the current regulatory period. As with our routine replacement expenditure, we only make investment decisions to replace assets following assessment of their actual condition during the current regulatory period, using the most recent information available. Again, this can result in projects being undertaken earlier or later than forecast within the regulatory period, not undertaken at all within the regulatory period, or undertaken within the regulatory period but with a different scope to that which formed the basis of our original replacement forecast.

During the current regulatory period, we have undertaken, or expect to undertake, the majority of the non-routine asset replacement projects that we included in our forecast at the time of the previous regulatory determination. However, there are four material non-routine replacement projects which we have not undertaken during the current regulatory period and instead, have included in our forecast expenditure for the next regulatory period.

Three of these deferred projects are interrelated. Our forecast capital expenditure for the current regulatory period included the replacement of switchgear at both Footscray East (**FE**) and Footscray West (**FW**) zone substations and relays at FW between CY18 and CY20. Both zone substations use the same makes and models of key equipment (not used elsewhere on our network) which exhibit similar condition degradation issues and were expected to reach the end of their useful lives during the current regulatory period. Given the similarity of the equipment and condition issues at two zone substations located close to each other, we considered that it would be prudent to stagger these works (rather than undertake the projects concurrently) to leverage learnings from the first project and maintain the security of supply to customers in the broader Footscray area.

<sup>7</sup> Non-preferred services are older types or models of overhead service which pose safety and fire start risks. We are continuing our program to replace all non-preferred services throughout our network due to the safety risks they pose to customers.

During the current regulatory period, our assessment of the condition of the assets at both FE and FW indicated that it would be possible to delay replacement of these assets without significant detriment to safety and supply reliability. We, therefore, deferred the replacement of equipment at FE (originally due to commence in CY18) to commence in late CY19, and we now expect to complete works at FE in the next regulatory period. As it remains prudent to stagger this program of works across FE and FW, and as our inspection activities continue to indicate that the health of the assets at FE is lower than at FW, we therefore also deferred the replacement of relays and switchgear at FW, and we now expect to complete those works during the next regulatory period.

The other material deferral we have identified is the replacement of transformers at Heidelberg zone substation. While detailed design work for this project commenced in CY19, this work identified complexities associated with underground assets located inside the zone substation site. This redesigned approach now requires works within the site to be undertaken in multiple stages, meaning expenditure will be incurred later than originally forecast.

As explained in Attachment 07-05, we have made adjustments to our forecast CESS payments included in our proposed revenues for the next regulatory period to account for these material deferrals, consistent with the methodology which has been outlined by the AER.<sup>8</sup>

### Customer-driven replacement activities

In aggregate for customer-driven replacement activities, we have overspent our allowance by \$19M (51 per cent). This category includes works undertaken in response to third party requests that we move or rearrange our assets. Customer requests wholly drive these works, and as such, the level of works we undertake can vary significantly from our forecast expenditures. During the current regulatory period, there has been an infrastructure construction boom in greater Melbourne, particularly in the road and rail infrastructure sectors driven by several large new government initiatives including the Level Crossing Removal Program and West Gate Tunnel project. This has led to historically high levels of demand from government and other authorities to relocate JEN's assets to allow for the construction of these projects, with demand being significantly higher than we had forecast in our previous regulatory proposal.

We have also incurred higher than forecast expenditure for emergency works to fix damage to our assets caused by unidentifiable parties.<sup>9</sup> This reflects the difficulty in forecasting such expenditure (noting the change in treatment in the current regulatory period from the previous regulatory period), which is again wholly driven by external factors.

---

<sup>8</sup> AER, *Better Regulation: Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, p. 9.

<sup>9</sup> The repair of damage to the network caused by liable third parties who are identifiable was unclassified during the current regulatory period, therefore expenditure in this category is not covered by this document.

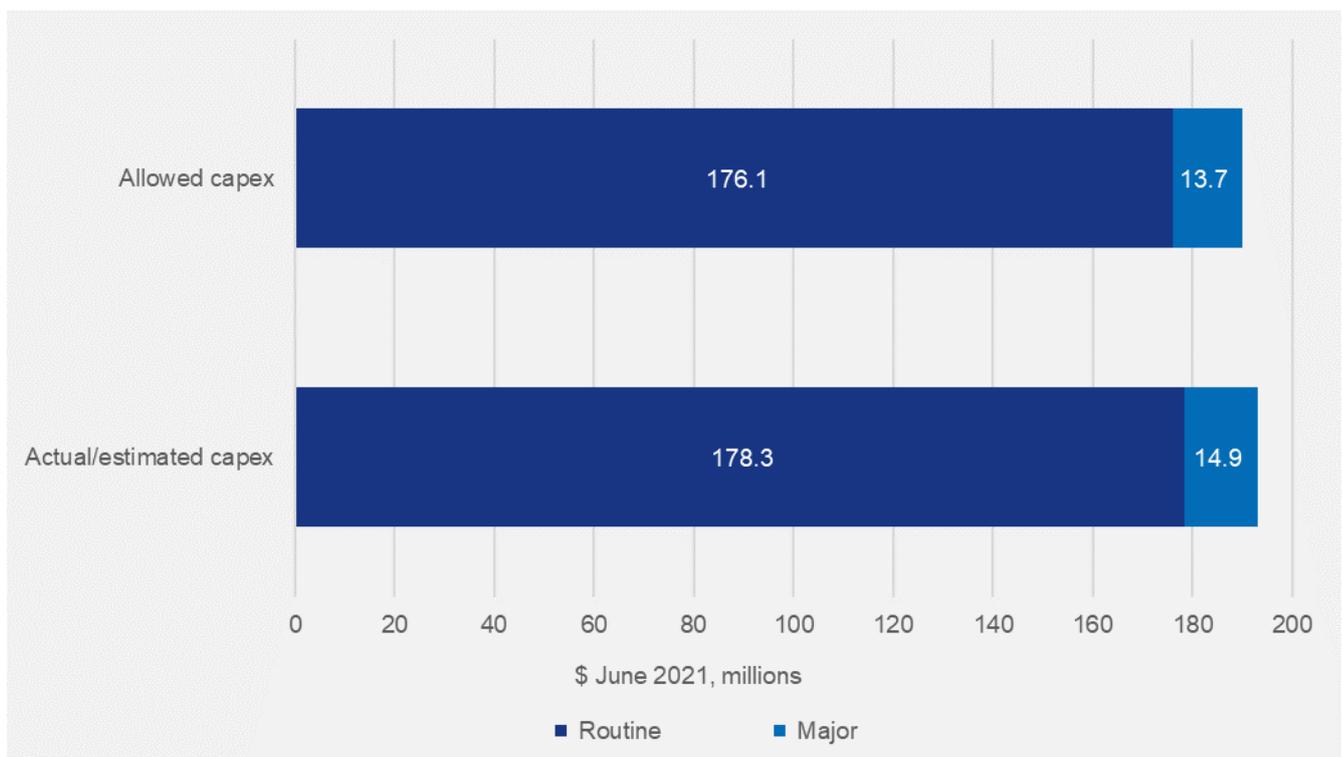
## 2. Connections

Connections expenditure<sup>10</sup> relates to the connection of new customers to our network and the augmentation or alteration of existing network connections. Connections expenditure can be classified into two categories which reflect the different forecasting approaches we employ:

- General connections – the vast majority of connections are in this category, with expenditure forecast using a top-down methodology
- Major customer connection projects – large, specific ‘one-off’ projects, with expenditure forecast using a bottom-up methodology.

In aggregate, we estimate that our total (gross<sup>11</sup>) connections expenditure for the current regulatory period will be \$193M. Our estimated connections expenditure this period is approximately \$3M (2 per cent) higher than our allowance for this category. Figure 2–1 shows the composition of our allowed and actual connections expenditure classified into the categories listed above.

**Figure 2–1: Connections expenditure for the current regulatory period (\$ June 2021, millions)**



The key drivers for our overspend in connections expenditure are discussed below.

General connections make up the majority of our connections expenditure. We forecast our general connections expenditure on a top-down basis, reflecting the fact that macroeconomic factors—such as population growth—are the key drivers of this expenditure. We develop these forecasts by customer type, using third party expert forecasts of the macroeconomic drivers that are most likely to influence our actual connections expenditure during the period.

During the current regulatory period, our routine connections expenditure was largely consistent with the total amount included for general connections in our allowance—our estimated expenditure being \$6M or 3 per cent above the corresponding allowance. For residential customer types, we saw higher than forecast expenditure

<sup>10</sup> All figures presented in this section reflect our gross connections capital expenditure for SCS—that is, capital expenditure including amounts which were contributed by the connecting customer.

<sup>11</sup> Not including capital contributions.

connecting new housing developments in greenfield areas (the northern and northwestern areas of our network), offset by lower than forecast expenditure on connections for smaller-scale residential subdivisions and redevelopments in brownfield areas. Our general connections expenditure for business customer types was in line with our forecast.

Our connections expenditure also includes some major customer connections projects. Major customer connection project activities and costs are forecast on a bottom-up basis using the information provided by individual large customers about their future connection requirements. As such, this expenditure is predominately driven by factors specific to those individual customers. During the current regulatory period, our expenditure on major customer connection projects exceeded the amount included in our allowance by approximately \$1M (8 per cent). In our forecast for the current regulatory period, we included only one major customer connection project, relating to an increase in supply to Melbourne Airport. We also expect to undertake works on two additional major connection projects before the end of the current regulatory period—connections for the West Gate Tunnel and North East Link projects. The requirements of these additional customers were not known at the time we prepared our forecast for the current regulatory period; therefore, these projects were not included in our regulatory proposal.

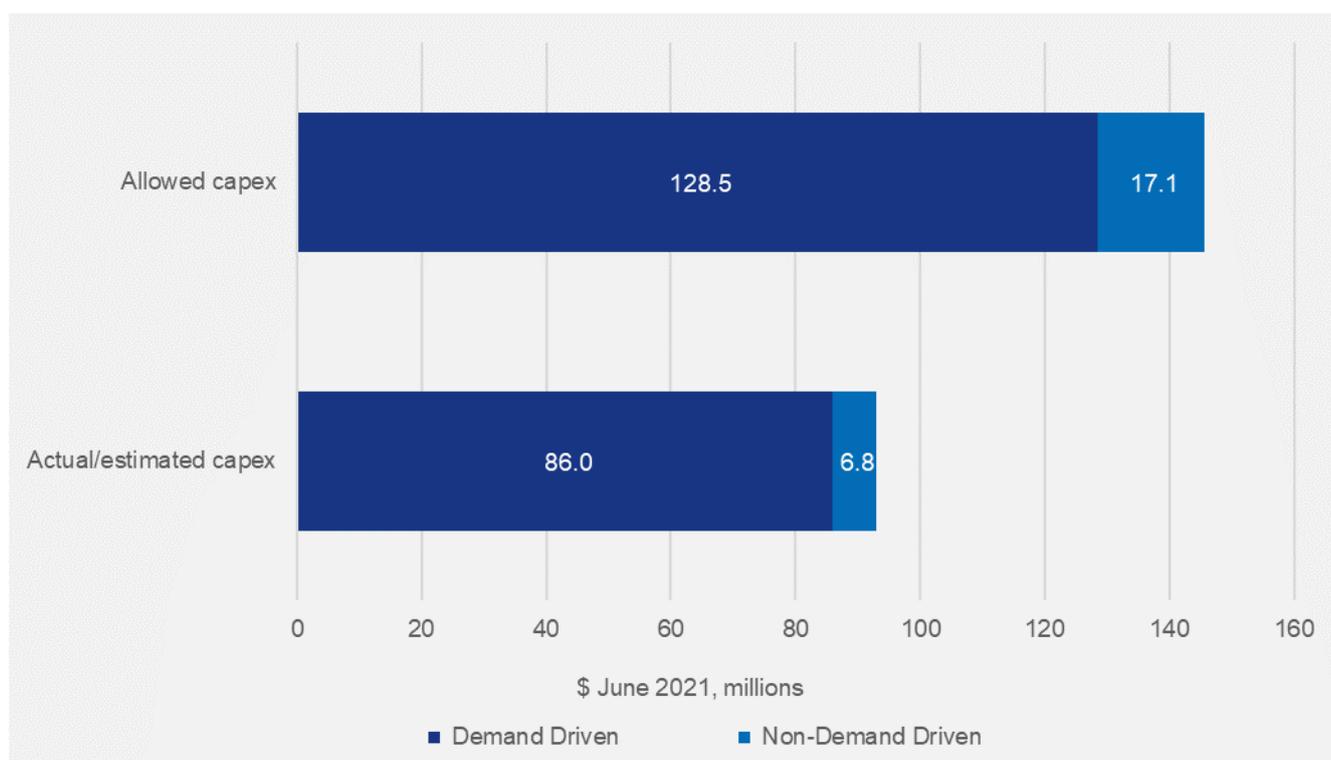
### 3. Augmentation

Augmentation expenditure relates to enlarging our network or its capability to distribute electricity. Augmentation expenditure can be classified into two categories which reflect different expenditure drivers:

- Demand-driven – expenditure to increase the capacity in response to the growth in the maximum demand our customers place on the network
- Non-demand driven – expenditure to increase the capacity of the network in response to customer-driven factors other than maximum demand growth, such as supply quality or compliance with environmental, safety and legal obligations.

In aggregate, we estimate that our total augmentation expenditure for the current regulatory period will be \$93M. Our estimated augmentation expenditure this period is 36 per cent lower than our allowance for this category. Figure 3–1 shows the composition of our allowed and actual augmentation expenditure classified into the categories listed above.

**Figure 3–1: Augmentation expenditure for the current regulatory period (\$ June 2021, millions)**



The largest contributor to this underspend has been softer-than-expected growth in demand, which reduces the need for demand-driven augmentation of the network. When forecasting demand-driven augmentation expenditure, we develop bottom-up spatial maximum demand forecasts at a zone substation or feeder level, which are reconciled to our externally-sourced top-down system-level maximum demand forecast.<sup>12</sup> We do this because viewing maximum demand at a system level can hide spatial diversity in demand at a zone substation or feeder level—with demand at these lower levels being the key driver of network augmentation. It should be expected that the rate of maximum demand growth at various locations within the network will differ significantly from the *average* rate of growth across the entire network. This is particularly relevant for JEN, given our network covers areas ranging from greenfield urban development corridors where demand is growing strongly, to older industrial areas where demand is declining as customers shut down. Furthermore, in practice, there are instances where actual spatial maximum demand has differed materially from forecast due to the decisions of individual large customers to connect, expand, contract or disconnect.

<sup>12</sup> Refer to Attachment 05-01 for further information about our forecasting approach.

At a spatial level during the current regulatory period, some areas of our network have experienced growth in customers' maximum demand below that which we originally forecast when developing our previous regulatory proposal. This has meant that it was not necessary to undertake some of the demand-driven augmentation projects we forecast, with slower maximum demand growth reducing the value of the load at risk—and therefore the economic value of undertaking some projects—for customers. A key area where we have spent less than originally forecast is on demand-driven distribution substation augmentation. Additionally, in some areas where we have seen spatial maximum demand growth above the levels we originally forecast, spare network capacity existed or we were able to undertake other works (such as rearranging assets) to meet growing demand requirements which resulted in lower augmentation expenditure. Overall, this has resulted in an underspend relative to our allowance for demand-driven augmentation expenditure.

The largest contributor to our underspend in augmentation expenditure has been our decision to defer the establishment of a new zone substation at Craigieburn. Craigieburn is a key growth area in Melbourne's north, and we originally forecast that HV feeders supplying this area would exceed their capacity by summer 2019/20. However, local demand has not grown as rapidly as originally forecast, and the shutdown of some major industrial customers in the Somerton area (just south of Craigieburn) has allowed us to repurpose and reconfigure the network in this area to supply new load in Craigieburn—representing an efficient alternative to meeting supply needs without building a new zone substation. We still expect to need to develop a new zone substation to supply the Craigieburn area at a later time, currently estimated to be in the early years of the RY27-31 regulatory period. Although we consider this to be a material project, we have not included expenditure for this project in our capital expenditure forecast for the next regulatory period; therefore this project does not represent a deferral for CESS adjustments within the framework set out by the AER.<sup>13</sup>

During the current regulatory period, we have not purchased land as planned for a future zone substation at Plumpton, as land in this area has not yet been subdivided and it, therefore, has not been possible to identify and purchase a suitable site. Due to the delay in subdivisions in this area, local demand growth will also be slower than originally forecast, and we now plan to purchase a site for this new zone substation after 2026. Our allowance also included expenditure for the purchase of the leased land that our Sunbury zone substation is located on; however, we were unable to secure favourable terms for the purchase of this site and have instead entered into a new long-term lease.

We also spent less than our allowance for non-demand driven augmentation projects; however, this has had a lesser impact on our augmentation underspend than demand-driven expenditure.

---

<sup>13</sup> AER, *Better Regulation: Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, p. 9.

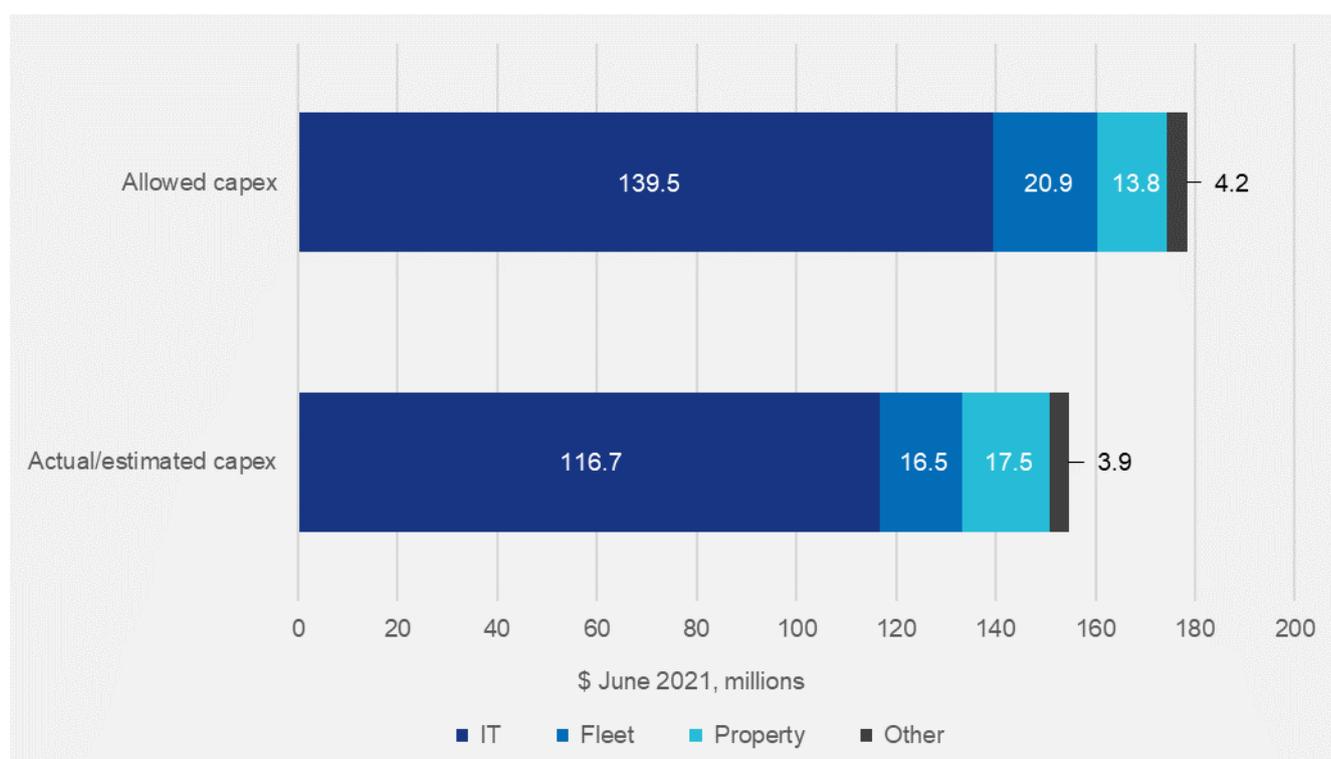
## 4. Non-network

Non-network capital expenditure relates to the assets we use in delivering standard control services to customers, but which do not form part of the physical distribution system. Non-network expenditure can be classified into two categories:

- Non-network IT – expenditure on information and communications technology assets which support a wide range of activities we perform to deliver services to customers
- Other non-network – comprising expenditure on vehicles, non-network property, tools and equipment.

In aggregate, we estimate that our total non-network expenditure for the current regulatory period will be \$155M. Our estimated non-network expenditure this period is 13 per cent lower than our allowance for this category. Figure 4–1 shows the composition of our allowed and actual non-network expenditure classified into two categories listed above.

**Figure 4–1: Non-network expenditure for the current regulatory period (\$ June 2021, millions)**



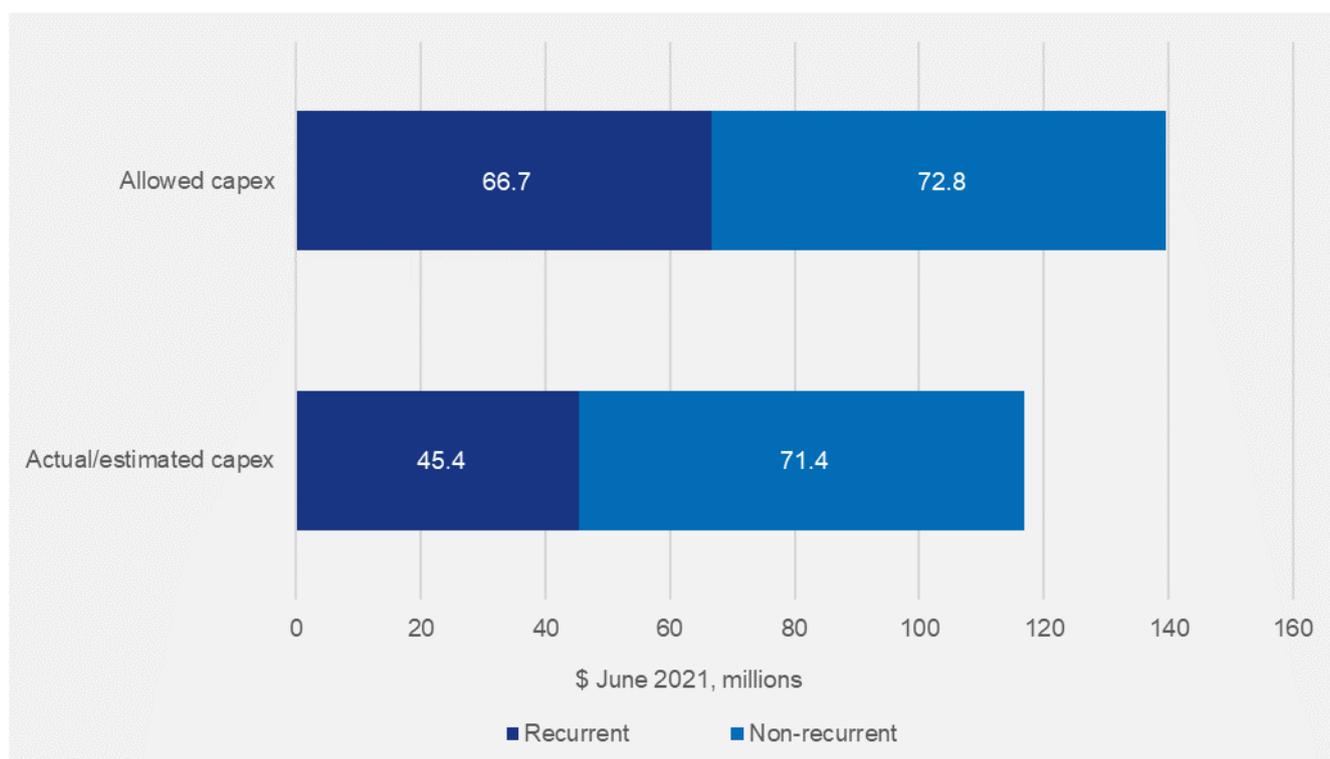
The key drivers of our underspend in our non-network expenditure are discussed in the sections below.

### Non-network IT

Within non-network IT, we have reported our expenditure against the categories of recurrent and non-recurrent, consistent with the AER's preferred approach.<sup>14</sup> Figure 4–2 shows our allowance and estimated expenditure in these categories, which are explained below.

<sup>14</sup> AER, *Non-network ICT capex assessment approach*, November 2019.

Figure 4–2: Non-network IT expenditure for the current regulatory period (\$ June 2021, millions)



### Recurrent expenditure

For the current regulatory period, we expect to underspend by \$21M for recurrent expenditure. A key driver of this underspend relates to hardware, where our recurrent expenditure was lower than forecast due to the purchase of some hardware as part of larger non-recurrent upgrade and replacement project activity, which displaced the need for some recurrent hardware expenditure during this period.<sup>15</sup> For example, as part of our non-recurrent SCADA OMS/DMS replacement project, we acquired all new hardware for the new applications.

Similarly, under our Five-minute and Global Settlement compliance project (which commences during the current regulatory period), we will acquire a substantial amount of additional storage capacity. Some of our forecast recurrent software expenditure has also been offset by non-recurrent software projects for compliance, capability growth or maintenance purposes. Our data warehouse systems have been refreshed as forecast. However, this occurred through a major upgrade and the implementation of a new HANA storage platform which is non-recurrent expenditure (given its size and likely technical lifecycle of more than five years).

During the current period, we undertook a program of virtualising server and storage platforms and standardising equipment versions to more widely-available models, this allowed a smaller number of larger-scale hardware units to support our growing collection of virtual servers more efficiently. This trend has resulted in reduced expenditure for the current period than originally forecast.

### Non-recurrent expenditure

Our current period's non-recurrent IT expenditure was in line with our forecast, with a less than \$1M underspend in aggregate for this category. Within this category, we spent more than originally forecast on maintaining existing system capabilities and complying with new regulatory obligations, and less than originally forecast on new system capabilities.

Non-recurrent maintenance expenditure was higher than forecast due to the implementation of larger-scoped or more complex system lifecycle upgrades than we had originally planned. As explained above, this had the effect

<sup>15</sup> Importantly, while some recurrent expenditure has been displaced by non-recurrent projects during the current regulatory period, it would be expected that the recurrent expenditure be required in subsequent regulatory periods during which those non-recurrent projects will not be undertaken.

of offsetting some recurrent lifecycle expenditure for software during the current regulatory period, and we expect to see a reversion to higher recurrent expenditure and lower non-recurrent maintenance expenditure next period. We also overspent on compliance activities, driven largely by the introduction of new regulatory obligations for five-minute settlement and global settlement which were not foreseen when our regulatory allowance was set. We have also spent more on uplifting our cyber-security capabilities in response to a growing external threat environment.<sup>16</sup>

These overspends were fully offset by the de-scoping and reprioritisation of non-recurrent new capability growth projects. In some cases, we had previously planned to undertake full re-platforming of some end-of-life systems, to both mitigate system lifecycle risks and provide a benefit-driven capability uplift. However, for systems such as our Customer Relationship Management and Human Resource Management, we have instead put in place new foundational systems with a stronger emphasis this period on ensuring technical stability of these systems. We also achieved some delivery efficiencies which enabled underspends on key capability extension projects which did proceed, for example through the use of standardised cloud-based solutions for Customer Relationship Management and Human Resource Management.

### Other non-network

For other non-network, we expect to slightly underspend our allowance in aggregate by \$1M.

For fleet, we expect to spend around \$4M less than our allowance, as we replaced fewer vehicles than we had originally planned within the passenger, light commercial and heavy commercial vehicle categories. This was mainly due to personnel and organisational structure changes which impacted our fleet management team, delaying the progression of internal expenditure proposals and approvals, and the need to prioritise the replacement of some elevated work platform vehicles which exhibited condition and work health and safety issues. A number of light commercial and passenger vehicles whose replacement has been delayed so far this period are now expected to be replaced in CY20 and FY22.

For property, we expect to spend around \$4M more than our allowance. This was is mainly due to our allowance not including any provision for minor ad-hoc property capital expenditure on items such as rectification of faulty or damaged building fixtures or office equipment. We have included such provisions in our forecast capital expenditure for the next regulatory period.

For tools and equipment, we expect to spend close to our allowance.

---

<sup>16</sup> Although this cyber-security uplift reflects growth in our systems' capability, we consider the drivers of this expenditure are more akin to compliance expenditure rather than the capability growth category set out by the AER.

## 5. Capitalised overheads

Our total capital expenditure for the current regulatory period includes an amount reflecting the capitalised portion of our overhead expenditure. This approach reflects the fact that some of the activities we carry out as a business which are classified as overhead in nature are necessary to support the delivery of our capital works program.

In aggregate, we estimate that our total capitalised overheads for the current regulatory period will be \$147M. Our estimated capitalised overheads expenditure this period is 21 per cent lower than our allowance for this category. This proportion is consistent with the magnitude of our overall underspend of 18 per cent in our program of capital works (direct expenditure) which these overhead costs support.