Jemena Electricity Networks (Vic) Ltd

Attachment 10-01

Advanced Metering Infrastruture

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Glossary

Next regulatory period	2026-31 regulatory control period commencing 1 July 2026
Current regulatory period	2021-26 regulatory control period commencing 1 July 2021
Previous regulatory period	2016-20 regulatory control period commencing 1 January 2016

Abbreviations

ACS	Alternative Control Service
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
AMI NICS	AMI Network Interface Cards
ARR	Annual Revenue Requirements
BIS	BIS Oxford Economics
CY	Calendar Year
DEECA	Department of Energy, Environment and Climate Action
EBBS	Efficient Benefit Sharing Scheme
DER	Distributed Energy Resources
DNSPs	Distribution Network Service Providers
EDCoP	Electricity Distribution Code of Practice
ESC	Essential Service Commission
FY	Financial year
GED	General Environmental Duty
HY21	Half year Jan to June 2021
IT	Information technology
JEN	Jemena Electricity Networks (Vic) Ltd.
JSA	Job Safety Assessment
MAB	Metering Asset Base
MAMS	Metering Asset Management Strategy
MDP	Meter data provider
NER	National Electricity Rules
NMS	Network Management System
NSW	New South Wales
OIC	Order In Council
PTRM	Post-tax Revenue Model
RFM	Roll-forward Model
SA	South Australia
SAP IS-U	SAP Industry Specific – AMI Utilities module
SAP ERP	SAP Enterprise Reporting Program
WAR	Work Activity Record

Overview

The Victorian Government has determined that in Victoria the electricity distribution businesses remain responsible for smart metering services for all residential and small business customers consuming up to 160 MWh of electricity per annum. The Australian Energy Regulatory (**AER**) has determined that these services are alternative control services (**ACS**) regulated via a revenue cap form of control.

Jemena Electricity Networks (Vic) Ltd. (**JEN**) has been providing Advanced Metering Infrastructure (**AMI**) services to our customers since we completed the mass rollout of the first generation of Victorian AMI meters between 2009 and 2013.

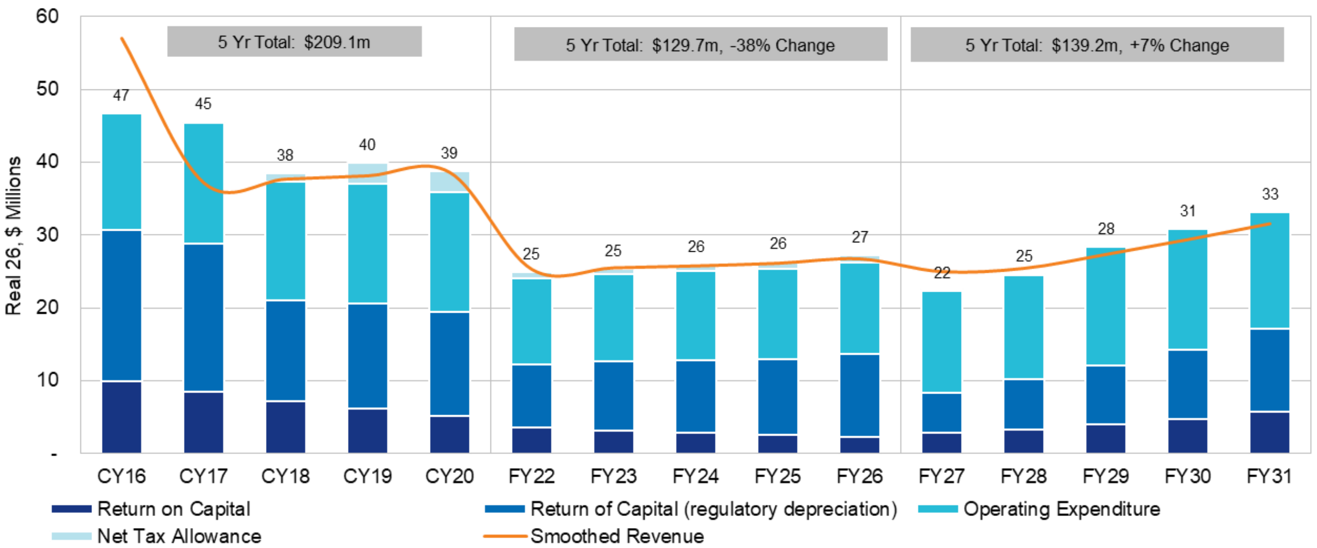
This attachment details our proposal to:

- continue providing ACS AMI metering services
- to efficiently meet our age-based AMI meter physical inspection obligations to conduct a site inspection of 78% of our AMI meters that exceed their 15 ears design life
- deliver a targeted and co-optimised proactive aged meter replacement program for 22% of our AMI meters whilst our inspection crews are on site and can identify meters at risk of imminent failure.

*In its response to our Draft Plan our Energy Reference Group (**ERG**) supported our co-optimised approach to jointly meeting our aged meter inspection obligations whilst proactively replacing first generation smart meters that are found to be high failure risk.*

Figure 0V-1 shows how that even with our new inspection obligations and proactive replacement activities, we will be able to deliver our ACS AMI metering services for $139.2 million dollars (building block revenue, $2026), which is 33% less than it cost us to provide the equivalent services in the 2016-20 regulatory control period (**previous regulatory period**) and only 7% higher than our current period costs.

Figure OV–1: Revenue requirement for metering services, Real $2026, millions (unsmoothed)



List of AMI metering service attachments

Table OV–1: List of smart metering service attachments

Attachment	Name	Author
02-09	JEN - MosaicLab Att 02-09 Energy Reference Group process report - 20240105	MosaicLab
05-04	JEN- Att 05-04 Customer numbers - 20250131	JEN
05-07	JEN - Oxford Economics Att 05-07 Real cost escalation report - 20241008	Oxford Economics
08-01	JEN - Att 08-01 Annual revenue requirement - 20250131	JEN
10-01A	JEN - Att 10-01A Appendix B Metering unit rate model - 20250131	JEN
10-02M	JEN – Att 10-02M ACS Metering PTRM – 20250131	JEN
10-03M	JEN – Att 10-03M ACS Metering opex and capex model – 20250131	JEN
10-04M	JEN – Att 10-04M ACS Metering RFM – 20250131	JEN
10-07	JEN - Frontier Economics Att 10-07 - Forecast replacement of smart meters - 20241220	Frontier Economics
RIN – Support	JEN – RIN – Support - Metering Asset Class Strategy – 20250131	JEN
RIN – Support	JEN – RIN – Support - Measurement Communications asset Class Strategy – 20250131	JEN
RIN - Support	JEN – RIN – Support – Metering Asset Management Strategy – 20250131	JEN
11-03M	JEN - Att 11-03M 2024-25 ACS Labour rate model - 20250131	JEN
RIN-4.6.1	JEN – RIN 4.6.1- Business Case - Inspection of Metering Installations - 20250131	JEN

1. About Victoria's smart metering infrastructure

1.1 What are smart meters?

Advanced Metering Infrastructure (**AMI**) consists of a smart meter which is an electronic meter that records energy consumption in intervals of 30 minutes, or 5 minutes for meters installed after December 2018, and a mesh communications network that transmits meter reading information back to us acting on behalf of customers as the metering data provider (**MDP**). This meter reading information is then passed on to a customer's electricity retailer for billing purposes and to the Australian Energy Market Operator (**AEMO**) to settle the electricity market.

Customers can also monitor their energy consumption in near real-time using a range of appliances that connect to the AMI meter to help them better manage energy costs.

1.2 Our smart metering regulatory context

In 2008 the Victorian Government mandated electricity distribution businesses to roll out AMI or 'smart meters', to all Victorian residential and small business electricity customers consuming up to 160 MWh of electricity per annum. The mandate set out in a November 2008 Order in Council (**OIC**), made under the Electricity Industry Act 2000 (Vic), required electricity distribution businesses to roll out AMI in accordance with prescribed metering standards, service levels and timeframe.[1] The rollout commenced in 2009 and was completed by the end of 2015.

Prices for smart metering services were regulated by the Australian Energy Regulator (**AER**) under the OIC until the end of 2015 and have since been regulated under the National Electricity Rules (**NER**). Since 2016 the AER has classified smart metering services in Victoria as alternative control prices (**ACS**) and applied a revenue cap form of price control to recover costs for providing AMI services.

For the 2026-31 regulatory control period commencing 1 July 2026 (**next regulatory period**), the AER will continue to regulate smart metering services under the NER using the same ACS regulated service classification and revenue cap mechanism as it did in the current regulatory period.[2]

In addition to price regulation by the AER, AEMO regulates how we manage, maintain, test, inspect and replace our meters. In particular, the NER[3] require us to have an AEMO-approved metering asset management strategy and to comply with it.

1.3 Customer and operational benefits of our smart meters

Our smart meters provide important benefits to our customers, assist us in managing the electricity distribution network and support Victoria's transition to a decarbonised and decentralised energy system, characterised by:

- Many customers who have invested in solar panels, batteries and electric vehicles
- Many customers and their retailers who seek to benefit from responding to time-variable price signals (e.g. peak and off-peak pricing)
- A need for more localised and granular data in how we manage power quality and outage detection and restoration.

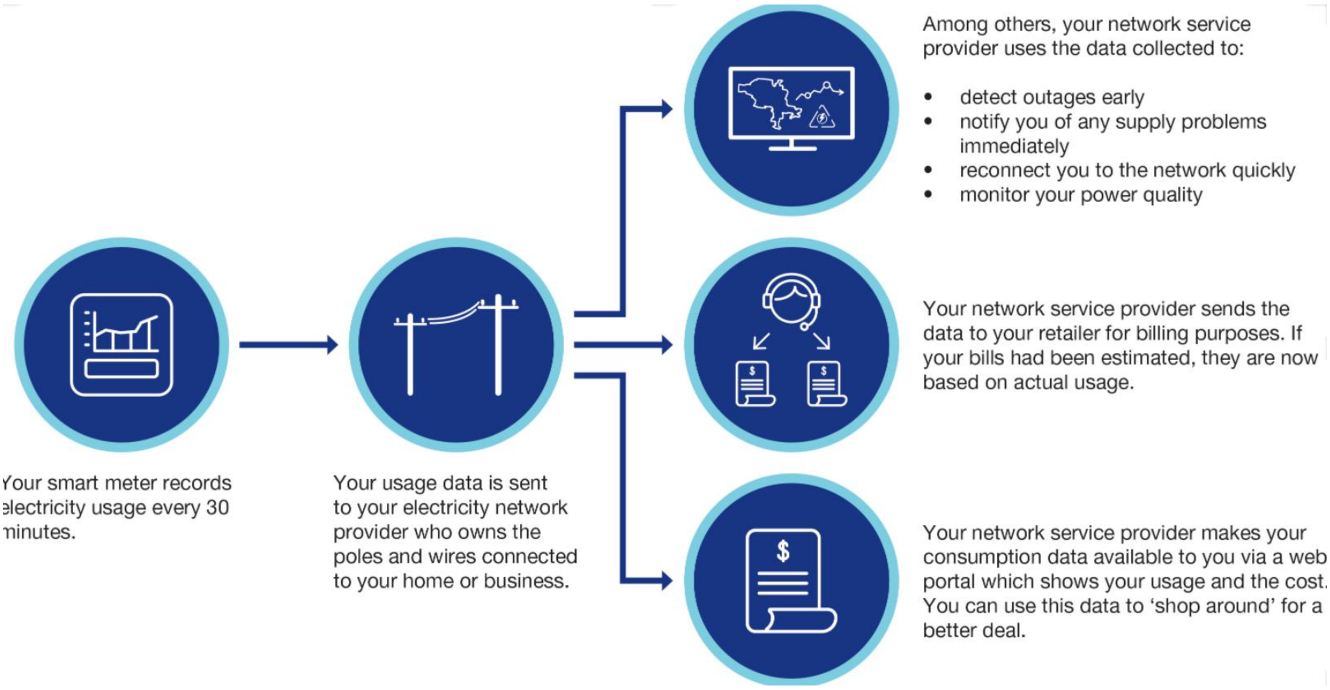
Figure 1-1 shows how these benefits arise.

[1] *Victorian Minimum Advanced Metering Infrastructure (AMI) Functionality Specification* v1.2; and *Victorian Minimum AMI Service Levels Specification.*

[2] AER, *Framework and Approach AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026-31*, July 2024, p.12.

[3] NER Clause 7.9 and Schedule 7.6.

Figure 1–1: How customers electricity retailers and distributors benefit from smart meters



Our smart meters facilitate the innovative design of the electricity distribution network and retail tariffs. Customers can access their energy consumption data via our Electricity Outlook portal and see how much electricity they are using and when they are using it. They can use their consumption information to compare retail market offers.

AMI also enables us to develop and apply smart technologies to the operation of and investment in the electricity distribution network. It gives us data and near real-time insight into the operation of network assets, which helps us to improve the efficiency and reliability of the electricity distribution network.

Table 1–1 provides a summary of the ways smart meters benefit our customers to date. We anticipate that as new innovations and energy markets evolve, the AMI system will continue to adapt, providing even greater benefits and supporting the transition to the renewable and sustainable energy system of the future.

Table 1–1: Benefits of the advanced metering infrastructure smart meters

Group Type	Benefit
JEN Customers	Remote meter reading – Eliminating the need for manual meter reading speeds up the delivery of meter data and decreases the risk of human error. This leads to more accurate energy bills and improved customer satisfaction.
	Remote connection and disconnection – We can connect and disconnect a customer's electricity supply remotely, reducing the cost and time required to provide these services from days and weeks to hours.
	Enable the connection of technology that connects new smart appliances to the AMI meter to facilitate home energy management.
	Enable customers to access their energy consumption data via JEN's Electricity Outlook portal and see how much electricity they are using and when they are using it. This data allows customers to better respond to price signals and compare retail market offers.
	With real-time data on energy consumption, customers can make informed decisions about their energy usage, leading to increased energy efficiency. This helps lower energy bills and promote energy sustainability.
	Allows solar customers to monitor the amount of energy they export back to the electricity network. This provides an accurate measurement of their solar feed in tariff and enables better energy consumption management.

Group Type	Benefit
JEN - Future Network & Planning	Provide information regarding consumption usage patterns, enhance the demand response, and improve electricity supply chain efficiency.
	Improved demand forecasts on the electricity distribution network, allowing JEN to target our capital spending more effectively.
	Enable the integration of energy generated by customers through distributed generation to support the energy transition towards zero-carbon future.
	Advanced analytics – Provides JEN with rich data on energy consumption, generation and voltage performance. This data can be analysed to identify patterns, trends, and opportunities for network improvement. This allows JEN to make informed decisions about its operations and improve the overall network performance.
	Real-time monitoring will improve the health of the network, promote the safety to customers' supply services, and ensure ongoing conformance.
JEN- Network Operations	Outage management – Improve responsiveness to supply outages through automated outage notifications. This results in improved supply reliability for customers.
	Reduce hazards by remotely identifying poor connections. The AMI system allows us to detect whether a customer has a faulty meter or overhead supply cable service that needs replacing.
	Planned switching activities – More frequent and accurate updating of AMI data in JEN's Geographical Information System (**GIS**) mapping in its outage management system (**OMS**) improves the forecasting accuracy to predict the scope of JEN's planned network switching activities.
	Enable JEN to calculate outage times and durations. This information improves the calculation accuracy of our reliability metrics (SAIFI, SAIDI) and identifies the best and worst performing circuits which enables JEN to develop the most cost-effective action plan for future grid modernisation investments.
	Allows JEN to comply with regulatory obligations that explicitly call for AMI data as the source for performance reporting.

1.4 Victorian government metering policy

1.4.1 Provider of metering services in Victoria

The Victorian Government has determined that in Victoria electricity distribution businesses remain responsible for smart metering services for all residential and small business customers consuming up to 160 MWh of electricity per annum.[4] Similar arrangements apply in the Northern Territory, Western Australia and Tasmania.

In contrast, South Australia (**SA**), New South Wales (**NSW**), Queensland and the Australian Capital Territory (**ACT**) commenced a gradual smart meter deployment on a new and replacement basis since December 2017. This approach meant customers in those jurisdictions who get a smart meter have that meter provided by a provider appointed by the customer's chosen electricity retailer.

The Australian Energy Market Commission (**AEMC**) has foreshadowed an acceleration of the smart meter deployment in SA, NSW, Queensland and the ACT by 2031. Those arrangements will have little impact in Victoria because of the accelerated smart meter rollout that was completed in 2013.

1.4.2 Future-proofing the meter and service level specifications

Like all technologies, the technology in smart meters is evolving. While all our first generation of AMI meters met the Victorian government's minimum metering specifications, the generation of meters we install now have more capabilities than those we first started rolling out in 2009.

The first generations of AMI meters equipped JEN with the following capabilities:

[4] *AMI (Obligations to Install Meters) Order* means the Advanced Metering Infrastructure (Obligations to Install Meters) Order 2017 made on 10 October 2017 under sections 15A and 46D of the Electricity Industry Act 2000 and published in the Government Gazette S342 on that day as amended from time to time.

- Usage of AMI metering last gasp data in its outage management system which allows near real time monitoring and management of customer supply availability and status, allowing faster customer supply restoration in an event of network outage
- Monitoring and management of the AMI meter terminal cover tamper events and run analytics to determine the integrity and safety of the metering installations (not currently done in development)
- Monitoring and management of the AMI meter main cover tamper events and running analytics and investigations to determine the integrity and safety of the AMI meters and to prevent illegal and unauthorised usage of electricity
- Monitoring voltage and current fluctuations, sag and swell events from the AMI meters which can be combined with other network monitoring devices (including SCADA & Power Quality Meters) to run analytics and investigations to determine if meter installations have been subjected to any tampering
- Monitor the power quality and other characteristics of the electricity supply to ensure compliance and safety of the electricity connection at the point of metering
- Monitoring the electricity supply, live and neutral incoming and outgoing current magnitude and other characteristics and then performing analytics to determine the integrity of the supply neutral from the network to the point of connections/metering installations. (In Development). This feature will provide validation of customer site safety and prevent electric shock hazards due to deterioration or disconnection of the neutral wire, reducing the need to perform a Neutral Integrity Test
- Identify active meters with no load and disconnected sites with load
- Monitoring 3 phase meters voltage to determine if meter has been tampered with – through better protection, more accurate energy is reported, allowing network costs to be recovered more equitably.

The second generation of AMI meters represents an incremental improvement over the original specification delivering:

- support for 5-minute interval reads
- faster and more robust communication
- increased internal data storage
- improvements to data security.

While technology in smart meters is evolving, so too are customer expectations for the services meter devices can provide. The existing fleet of the first and second generation of AMI meters is ageing, and the technology it is based on no longer reflects modern customer needs and use cases that a new generation of AMI meters can fulfil. These include:

- New customer-focused interfaces to AMI meters for in-home real-time reading of the metering data on connected mobile devices (e.g. using wi-fi or Bluetooth)
- Configurable customer load monitoring and control schemes to allow customers to remain within the prescribed capacity limits
- Inbuilt capabilities to manage and temporarily limit customer export capacity
- Advanced power quality monitoring and control features, such as local supply frequency disconnection schemes to ensure network stability

JEN is working with the Department of Energy, Environment and Climate Action (**DEECA**) to monitor and evolve the currency of the Victorian AMI functional and service level specifications. This includes considering whether and if so, how various national meter-enabled rule changes made by the AEMC should be applied in Victoria.[5]

These specifications may change from time to time to stay up to date with the evolving needs of our customers and the energy system. If this happens, we will seek a regulatory change event pass through to adjust our ACS metering services revenues for the additional costs or savings arising from those changes. Section 6.3.1 explains how these mechanisms work within the metering services revenue cap formula.

1.5 Scope of our metering services

Our ACS metering services cover activities relating to the measurement of electricity supplied to and from customers through the distribution system (excluding network meters).

The scope of our Type 5 (including smart metering) services[6] where the JEN remains responsible, involve:

- recovery of the cost of type 5 metering equipment, including communications network (including meters with internally integrated load control devices)
- testing, inspecting, investigating, maintaining, or altering existing type 5 metering installations or instrument transformers
- metering data services that involve the collection, processing, storage and delivery of metering data, the provision of metering data from the previous two years, remote or self-reading at difficult to access sites, and the management of relevant NMI Standing Data in accordance with the NER.

5 For example, the AEMC is considering or has made the following rule changes for which the relevant NER provision do not apply to Victoria and instead reply upon the Victorian government's gazetted OICs: Accelerating smart meter deployment, Real-time data for consumers, Cyber security roles and responsibilities.

6 JEN also has other fee for service ACS metering services for 'Auxiliary metering services (type 5 to 7 including smart metering) where the DNSP remains responsible' which include a series of customer initiated meter activities.

2. Looking back over the current regulatory period

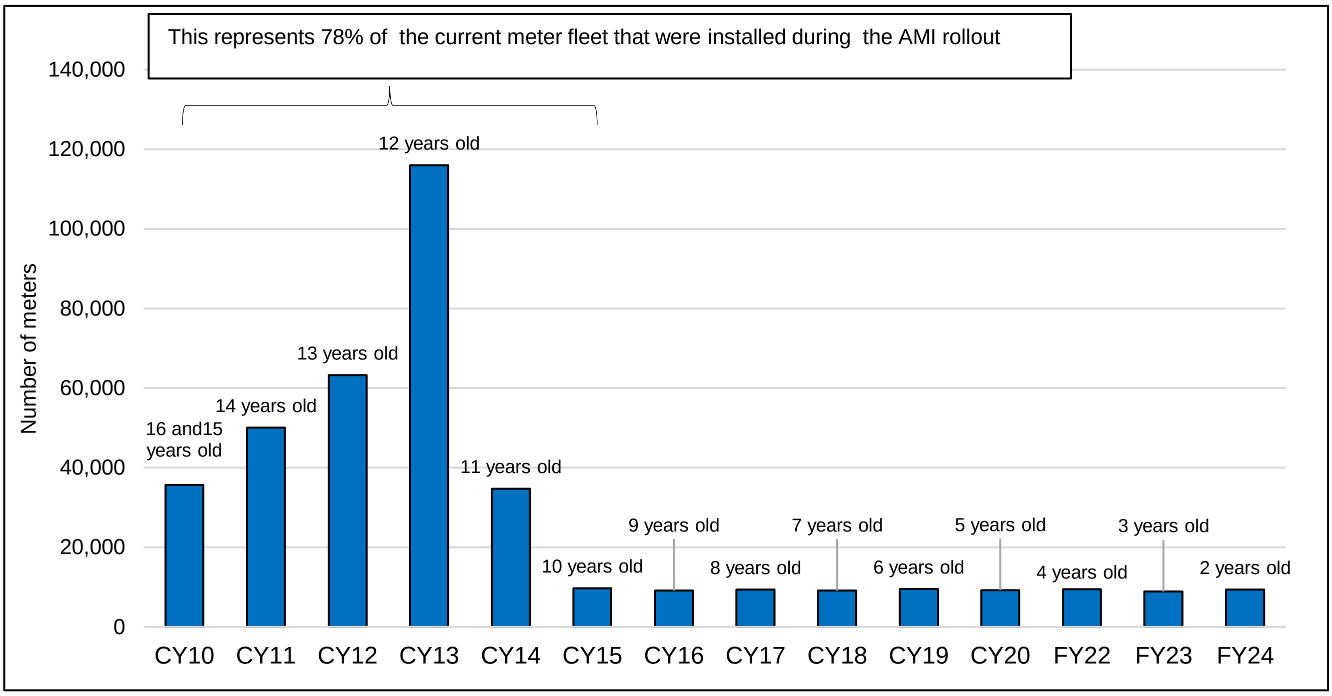
2.1 How our metering fleet has changed over the current regulatory period

Since the commencement of the 2021-26 regulatory control period (**current regulatory period**), our metering fleet has changed due to several key drivers:

- New connections growing the size of our meter fleet by approximately 7,000 – 9,000 customers per annum
- An increasing number of customers seeking three-phase meters due to the high electrification demands of customers who no longer use gas appliances or petrol vehicles, including in light of the Victorian government's ban on new residential gas connections
- Our targeted replacement program is to replace our remaining 4,031 legacy (non-AMI) meters with smart meters.

Figure 2-1 shows the age of our meters as of 2025 based on the recorded year of installation since the 2009 Victorian-mandated AMI rollout.

Figure 2–1: Number of AMI meters by age and installation years)[7]



2.2 Our expenditure and meter numbers over the current regulatory period

Figure 2-2 shows how our metering capital expenditure compares to the forecasts approved by the AER in our current regulatory period metering service allowances. The significant increase in the forecast capex for FY26 is due to JEN ramping up the replacement of approximately 3000 of our remaining legacy non-AMI meters (as shown in Figure 2-4).

7 JEN installed 5% of its then meter fleet in 2009.

Figure 2–2: Actual capital expenditure compared against allowance ($June 2026, millions)

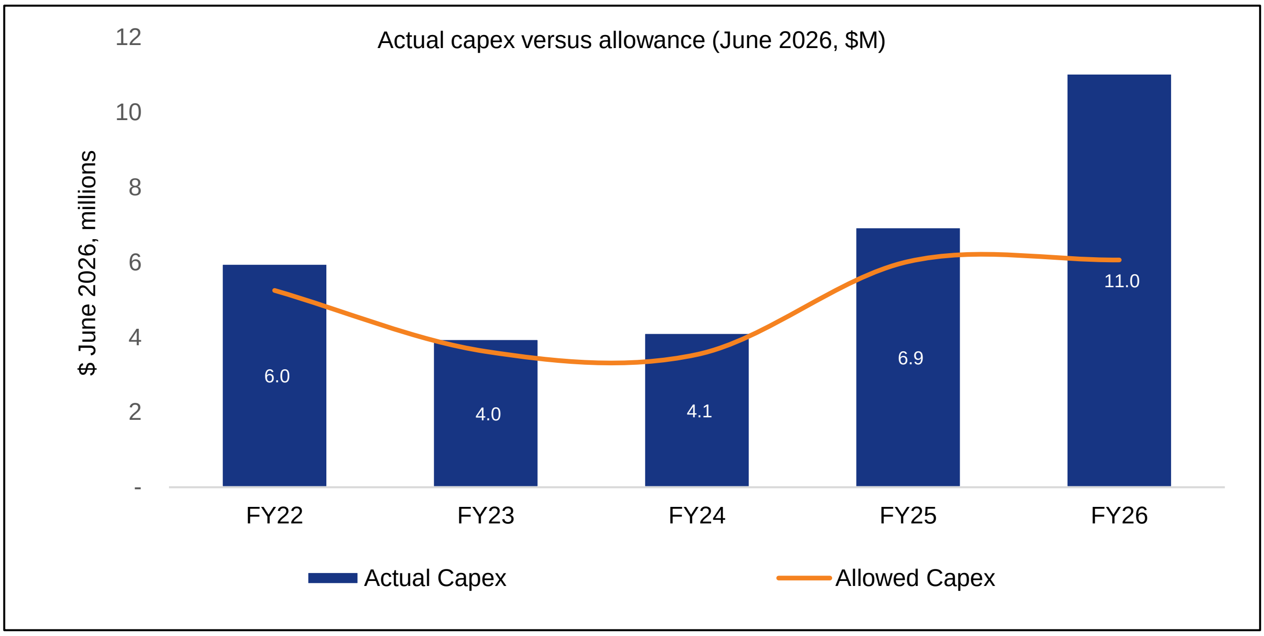


Figure 2-3 shows how our metering operating expenditure compares to the allowance approved by the AER in the current regulatory period.

Figure 2–3: Actual Operating expenditure compared against allowance ($June 2026, millions)

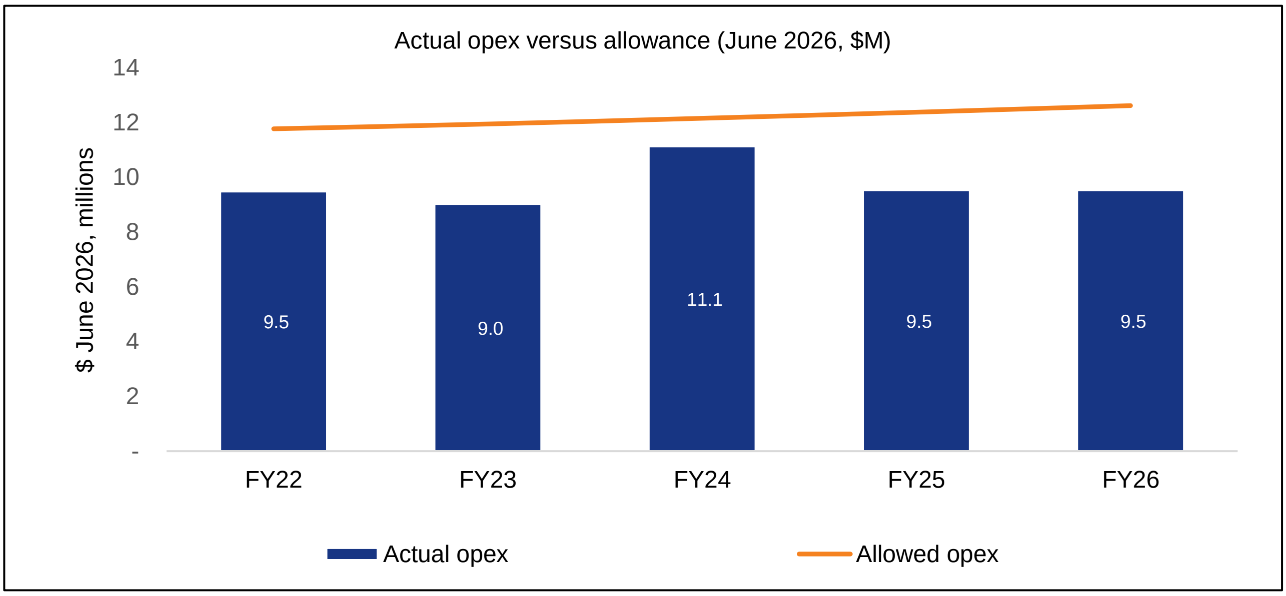


Figure 2-4 shows our meter installations and replacements by meter type during the current regulatory period. It shows that in addition to meeting significant annual new customer growth, our meter failure rates have begun to climb as the first generation AMI meters hit end of their design life, and that we will complete the replacement of our remaining legacy (non-AMI) meters by the end of FY26.

Figure 2–4: 2022-26 meter installations and replacements by meter type

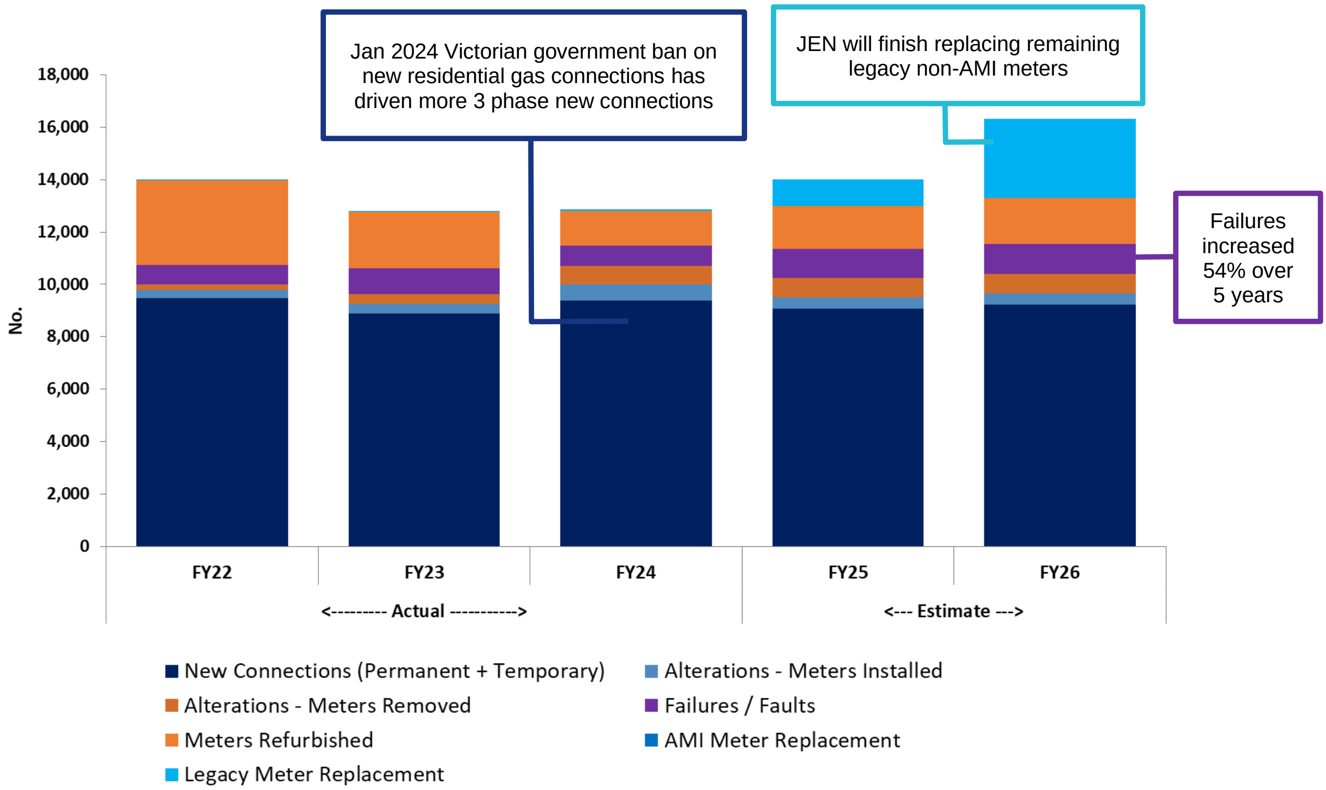
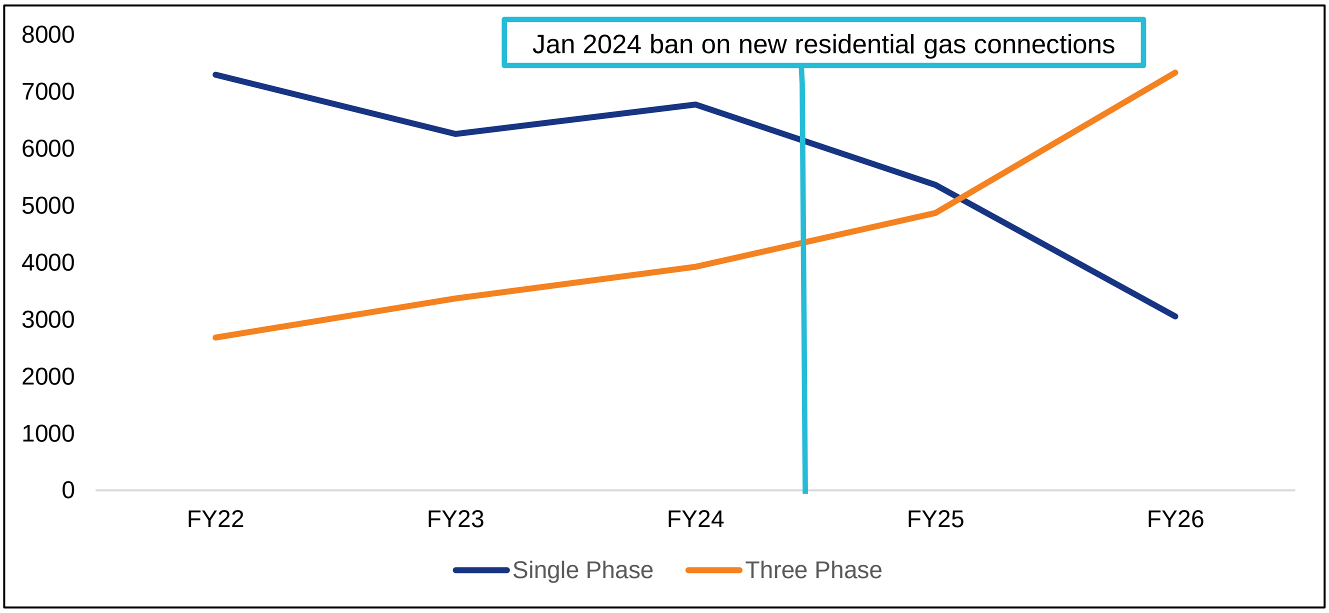


Figure 2–5 shows that the trend of more customers requesting three-phase meters was evident even before the compounding impact of Victorian electrification policies, discussed below.

Figure 2–5: Single versus three-phase meter trend



The nature of the Victorian government's policies for gas substitution mean the pace of three phase meter demand growth and single phase meter decline will hasten in comparison to current trends.

The following 2024 Victorian policies have been enacted or announced:

- on 14 December 2023, Victoria's Gas Substitution Roadmap annual update was published and committed the Government to investigate options to progressively electrify all new and existing residential and most commercial buildings, including through a Regulatory Impact Statement (**RIS**) and public consultation[8]
- from 1 January 2024, the Victorian Government has banned new gas connections for new dwellings, apartment buildings, and residential subdivisions requiring planning permits[9]
- from 1 January 2025, the Essential Services Commission's Gas Distribution Code of Practice (updated 1 October 2024) requires gas distributors to impose full upfront charging on customers for new gas connections[10]

The full effects of these policies are not yet evident in the Figure 2–5 because developments that already had planning approval before January 2024 were not affected by the ban. JEN expects that after these grandfathered developments are completed, all future greenfield developments will seek 3 phase metering to meet the needs of all electric homes.

2.3 Our customers' feedback

While our customers did not provide specific feedback regarding metering services, several of their recommendations require our smart metering fleet to remain operational and reliable. These recommendations included:

- Our Local Councils engagement identifying that these stakeholders felt that: '*JEN should be supporting smart networks and providing valuable energy usage data to Councils and communities to inform decision-making*'[11]
- Our Customer Voice Group expressed that: '*Young people want us to have fair and equitable tariffs for our customers and that customers who are exporting excess solar energy back into the electricity network, should have appropriate tariffs that reflect their needs versus customers without solar. This is important to young people so that customers without solar do not cross-subsidise those that have the benefits of solar*'[12]
- Our People's Panel recommended (recommendation #5) that we implement "*digitisation and automation to increase economic efficiency*".[13] By integrating AMI with other technologies, we are better able to meet the objective of efficient investment and operations of the electricity network.

JEN cannot deliver on these customer preferences without a reliable and well-maintained fleet of smart meters, which this proposal seeks to ensure will remain the case until 2031, at which point 78% of our first-generation smart meters will reach the end of their design life.

Many of our future network initiatives, aimed at connecting our customers to renewable sources of energy and accommodating more CER into our network, are integrated with our advanced metering infrastructure. We will only realise the benefits of those initiatives with our reliable and functioning smart meters. Given this, we believe that our proposed metering services and annual revenue requirements will address our customers' expectations of digitisation and automation and champion renewable energy generations.

In its response to our Draft Plan our ERG supported our co-optimised approach to jointly meeting our aged meter inspection obligations whilst proactively replacing first generation smart meters that are found to be high failure risk. This is discussed further in section 5.5 of this attachment.

8 Victoria's Gas Substitution Roadmap

9 Amendment VC250 was gazetted on 1 January 2024 and introduces new requirements for the construction of new dwellings, apartments and residential subdivisions that require a planning permit through a new particular provision at clause 53.03. No New Gas Connections in Victoria

10 Gas Distribution Code of Practice

11 Gauge Consulting Att 02-06 Local Council forum report – 20240106, p.8.

12 MosaicLab Att 02-04 Customer Voice Group process report - 20240107, p.20.

13 MosaicLab Att 02-09 Energy Reference Group process report - 20240105, p.44.

2.4 Implications for the next regulatory period

These trends mean that we enter the next regulatory period with:

- All our metering customers will be on smart meters by the end of the current regulatory period
- 78% of our meters reaching the end of their 15-year design life with failure rates climbing
- A clear customer preference for three-phase meters in light of the Victorian gas substitution roadmap and new residential connections ban, together with transport electrification, driving developer demand for all new meters to be three-phase meters.

3. Our revenue requirement for smart metering services

3.1 How we set our revenue requirement

Similar to our approach for calculating standard control services (**SCS**) revenue requirements in the next regulatory period, we have continued to use the AER's building block model to determine our annual revenue requirements (**ARR**) for the provision of smart metering services. Our proposed ARR is the sum of:

- return on capital (also known as the return on assets), which represents the benchmark financing costs of investing in our AMI comprising of smart meters, the communication network and related IT systems. The return on capital for a given year is calculated by multiplying the rate of return by our forecast metering asset base (**MAB**) at the start of that year
- regulatory depreciation (also known as the return of capital), which represents the payback of our investment in or MAB
- operating expenditure allowance, which represents the estimated prudent and efficient costs of operating and maintaining our metering system
- corporate income tax allowance, which represents the estimated cost of corporate income tax for a benchmark firm providing electricity distribution services.

Table 3-1 details our unsmoothed and smoothed ARR for the next regulatory period. We prepared this forecast using the metering Post Tax Revenue Model (**PTRM**), which is included in Attachment 10-02M.

Table 3–1: Annual revenue requirements for smart metering services ($ June 2026, millions)

	FY27	FY28	FY29	FY30	FY31	Total
Return on capital	2.8	3.3	4.0	4.7	5.7	20.4
Regulatory depreciation	5.5	6.9	8.1	9.5	11.4	41.4
Operating expenditure (including debt raising costs)	14.0	14.4	16.3	16.6	15.9	77.2
Revenue adjustments	-	-	-	-	-	-
Cost of corporate income tax	0.1	0.0	-	-	0.1	0.2
Annual revenue requirements (unsmoothed)	22.4	24.6	28.3	30.8	33.2	139.2
Annual revenue requirements (smoothed)	**25.0**	**25.5**	**27.4**	**29.4**	**31.6**	**138.8**

Source: *JEN - Att 10-02M ACS Metering PTRM - 20250131.*

Figure 3–1 shows our revenue requirements for each period and the trend in our metering revenue over the previous regulatory period, current regulatory period and next regulatory period. This figure shows that there has been a steady decrease in our metering revenue over the three regulatory periods, and illustrates the drivers of this.

The key drivers for our revenue requirement for metering services are meter replacements (capital expenditure) and in person inspections of meters (operating expenditure). Despite the new obligations affecting our operating costs for metering, the average metering cost per customer across the five years is forecast to remain at the current level of $25 (in real terms) per customer. Below we discuss each revenue building block which contributes to our ARR.

Figure 3–1: Revenue requirement for metering services, ($June 2026, millions)

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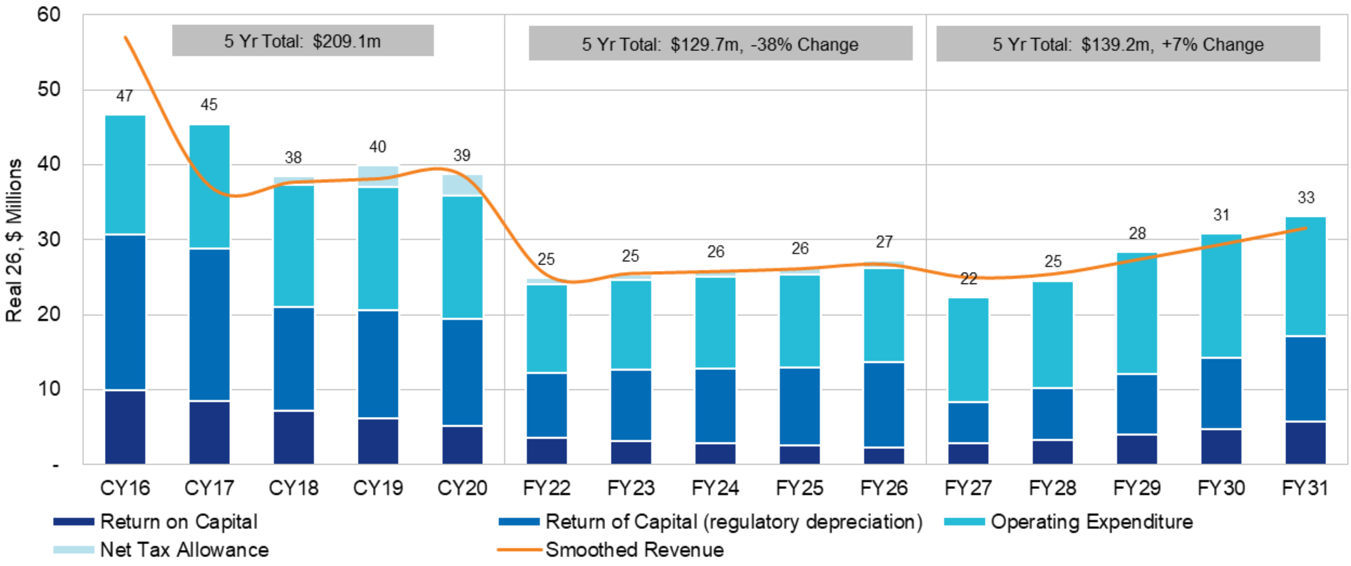


3.2 Return on capital

The forecast return on capital represents the cost of financing our investments in AMI, and it varies with the rate of return and the size of our MAB. To determine the forecast return on capital building block, we adopted the same approach as for rate of return for our SCS revenue requirements, which is described in Attachment 08-01. The return on capital shown in Table 3-1 will be updated each year annually to reflect changes in return on debt.

3.3 Regulatory depreciation

Depreciation represents the use or consumption of an asset over its service life. Including regulatory depreciation in our metering annual revenue requirement enables us to recover our investment in AMI over time in accordance with the economic lives of the assets. This approach allows us to fund the purchase of new and replacement assets so that we can continue to provide our metering services in the future.

The AER's framework and approach considers forecast depreciation is the most appropriate approach for rolling forward the MAB to the commencement of the next regulatory period.[14]

The AER's approach in the PTRM for the calculation of regulatory depreciation for the current regulatory period is to apply the straight-line depreciation. It involves using the forecast indexation on the MAB and then dividing the amount by the weighted average remaining asset lives.

We have maintained the same asset classes for the next regulatory period as used in the current regulatory period. We have also maintained the same asset lives for the next regulatory period as used in the current regulatory period.

As per the AER's preference, the standard asset life for equity raising costs is calculated for each regulatory period based on the weighted average life associated with the forecast capital expenditure profile.

Table 3-2 shows the current and proposed standard lives. Our AMI depreciation for the next regulatory period, which is shown in Table 3-1 is the sum of the depreciation on:

- existing assets in our opening MAB at the start of the current regulatory period based on their remaining asset lives

14 AER, *Framework and Approach AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026-31*, July 2024, p.22.

- forecast capital expenditure over the next regulatory period based on their standard asset lives.

Table 3–2: Current and proposed standard lives (years)

MAB Asset Class	Standard Life – Current Period	Standard Life – Next Period
Remotely read interval meters & transformers	15.0	15.0
IT	7.0	7.0
Communications	7.0	7.0
Other	7.0	7.0
In-house software (Standard life tax Depreciation)	5.0	5.0
Buildings (Standard life tax Deprecation)	40.0	40.0
Equity raising costs	11.0	12.8

3.4 Operating expenditure

Our forecast metering operating expenditure reflects the costs we expect to incur in operating and maintaining our metering and related information and communication systems and administering our metering obligations in accordance with regulatory requirements for providing regulated smart metering services.

We have forecast the operating expenditure that we would incur in the next regulatory period to:

- maintain our existing smart metering installations—expenditure related to alteration, testing, and refurbishment
- operate and maintain our AMI communication network and information systems—expenditure associated with metering data services that involve the collection, processing, storage and delivery of metering data to the NEM in accordance with our regulatory obligations
- meet our market and regulatory obligations
- conduct meter inspections for our end of design-life AMI meters that were installed over 15 years ago.

3.4.1 Operating expenditure forecasting methods

We used two methods to develop our forecast operating expenditure, which are:

First, the base, step and trend method for operation and maintenance of smart meters, AMI communication network, and operating the related information technology. This method uses a base year that reflects efficient and recurrent operating expenditure and adjusts this to account for future changes in our circumstances and operating environment (changes in output and other cost inputs) over the next regulatory period.

To forecast the AMI operating expenditure for the next regulatory period, we:

- propose FY25 as the efficient base year since it is based on our latest actual data that will be available for the AER’s determination. In the revised proposal, we will use the audited AMI operating expenditure in FY25, which will form the basis for our forecast operating expenditure over the next regulatory period.
- trend the base year costs forward by escalating or de-escalating the forecast to reflect changes in key cost inputs including, real price growth and output growth.

  - for price growth—we applied the benchmark labour proportion of 59.7% of total operating expenditure consistent with standard control service operating expenditure. The labour escalator we applied to labour reflects the average of forecasts by BIS Oxford Economics and Deloitte Access Economics[15] of wage-price indices for the utilities sector. A report from BIS Oxford Economics explaining its forecast is provided as Attachment 05-07 to our regulatory proposal.
  - for output growth—we scaled the AMI operating expenditure based on customer numbers because it is the best measure of changes in metering service output and thus a driver of operating expenditure costs.
- include step changes in operating expenditure for:
  - *Inspections* | This step-change relates to the obligation for a visual inspection of AMI meters that is triggered by them hitting the end of their 15 year service life. It covers the costs for the physical inspections by qualified electricians, and IT systems capability licensing (operating expenditure) to help minimise the cost of inspections activities.
  - *Meter disposals costs* | This step-change relates to the costs we will incur to dispose of our replaced meters in a compliant manner.

  Appendix A sets out the nature of these step changes, the obligations driving them, how JEN has minimised their costs and how JEN has forecast their costs.

Second, we use specific year-on-year method for debt raising costs where the use of the 'base, step and trend' method is not representative of future costs. We estimated the incremental forecast costs for each year of the next regulatory period within the PTRM using the benchmark debt raising cost.

3.4.2 Our forecast operating expenditure

Table 3-3 summarises our forecast operating expenditure for smart metering services over the next regulatory period. The calculations of these costs are detailed in the metering capital and operating expenditure model, Attachment 10-03.

Table 3–3: Forecast operating expenditure for metering services ($ June 2026, millions)

Metering services operating expenditure	FY27	FY28	FY29	FY30	FY31	Total
Base year total operating expenditure (excluding debt raising costs)	9.6	9.6	9.6	9.6	9.6	47.9
Price growth	0.1	0.2	0.2	0.3	0.3	1.2
Output growth	0.3	0.5	0.7	0.9	1.0	3.4
Productivity growth	-	-	-	-	-	-
Step changes	4.0	4.1	5.7	5.9	4.9	24.5
Debt raising costs[16]	0.0	0.0	0.0	0.0	0.0	0.2
Operating expenditure (including debt raising costs)	**14.0**	**14.4**	**16.3**	**16.6**	**15.9**	**77.2**

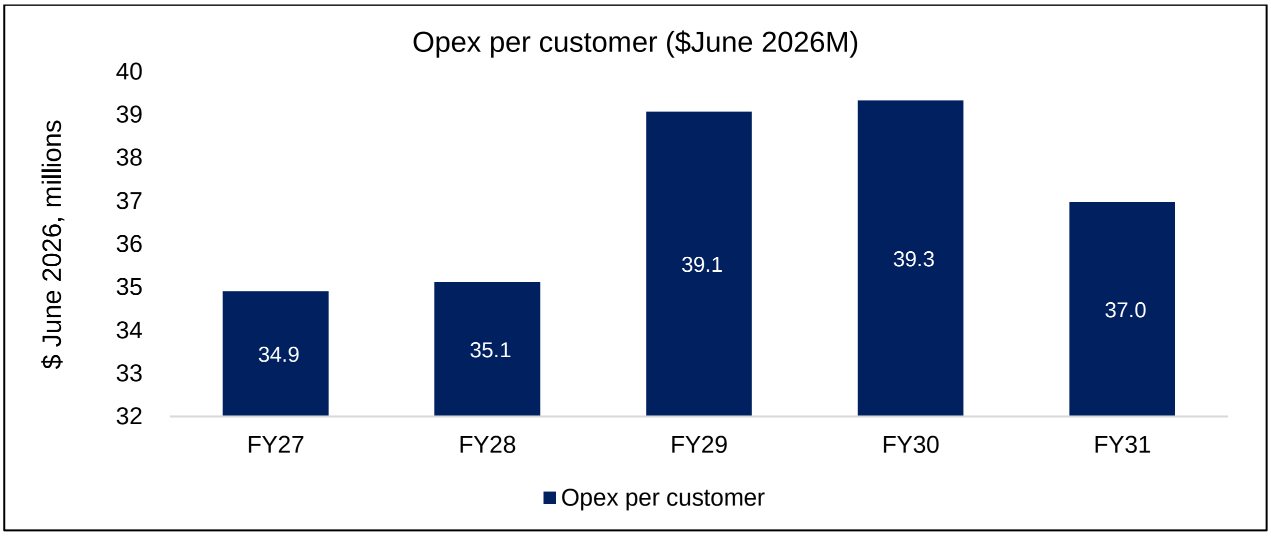
[15] JEN has used Oxford Economics' forecast Wage Price Index of the Victorian Electricity, Gas, Water and Waste Services ('Utilities') sector, sourced from Attachment 05-07.

[16] See *Attachment 10-04M.*

Source: *JEN - Att 10-03M ACS Metering opex and capex model - 20250131.*

3.4.3 Our operating expenditure is efficient

As Figure 3–1 shows, our base operating expenditure has declined since the previous regulatory period and base operating expenditure has remained low at $9.6 million ($2026), which has been achieved even amid significant inflationary and wage pressures over that period.



Our step changes proposed for the next period have efficiently co-optimised our capital expenditure and operating expenditure for lowest total cost of ownership in the ongoing provision of AMI metering services as evidenced in RIN-4.6.1.

3.5 Cost of corporate income tax

Our proposed approach to the calculation of corporate income tax allowance for smart metering services is the same as that for SCS. The corporate income tax allowance for smart metering services is calculated using four components:

- pre-tax revenues – any factor that changes our revenues will change these pre-tax revenues
- tax expenses, including tax depreciation, interest and operating expenditure
- the statutory corporate tax rate, which is set at 30%
- gamma, which is the expected proportion of company tax that is returned to investors through the utilisation of imputation credits.

Net taxable income is derived from pre-tax revenues less tax expenses. Applying the statutory corporate tax rate to net taxable income leads to forecast tax payable. The forecast tax costs are then adjusted to remove the estimated value of imputation credits (gamma) created by paying tax to set the allowance for corporate income tax.

We have forecast our corporate income tax allowance using the AER's PTRM. Table 3-4 outlines the calculation of our estimated corporate income tax.

Table 3–4: Estimated corporate income tax ($ June 2026, millions)

Corporate income tax	FY27	FY28	FY29	FY30	FY31	Total
Tax payable	0.3	0.1	0.0	0.0	0.2	0.5
Less value of imputation credits	-0.1	-0.0	0.0	0.0	-0.1	-0.3

Corporate income tax	FY27	FY28	FY29	FY30	FY31	Total
Estimated corporate income tax	**0.1**	**0.0**	**0.0**	**0.0**	**0.1**	**0.2**

Source: *JEN - Att 10-02M ACS Metering PTRM 20250131.*

4. Our metering asset base

The value of the AMI asset base we use in providing our smart metering services is known as the metering asset base (**MAB**). The MAB represents the as yet unrecovered capital expenditure that we have incurred to provide smart metering services to our customers consuming less than 160 MWh per annum.[26] Our MAB changes from year to year by:

- adding indexation
- adding metering capital expenditure
- deducting straight-line depreciation
- deducting the residual value of asset disposals.

The MAB is used to calculate two elements of our ARR for the provision of smart metering services; these are:

- return on capital—this is calculated by multiplying the opening MAB and the rate of return for a given year. It reflects the financing costs of our investments in the MAB
- regulatory depreciation—this reflects the payback of our investments in the MAB using the asset lives provided above in Table 3-2.

The MAB is also used to determine the debt raising cost allowance in the forecast operating expenditure forecast.

4.1 Opening metering asset base as at 1 July 2026

We have used the AER's Roll-Forward Model (**RFM**) to roll-forward our MAB for smart metering services of our current regulatory period. This approach to rolling forward the MAB is consistent with the approach used by the AER in its decision for this service in the previous regulatory period.

Table 4–1 details the outcomes of our MAB roll-forward calculation.

Table 4–1: Opening MAB as at 1 July 2026 ($ Nominal, millions)

	FY22	FY23	FY24	FY25	FY26
Opening MAB	60.6	57.7	53.7	51.3	48.9
Plus capex	5.1	3.5	3.9	6.9	11.2
Plus indexation	0.5	2.0	4.2	2.1	1.3
Less straight-line depreciation	-8.5	-9.4	-10.5	-11.3	-12.1
Adjustment	0.0	0.0	0.0	0.0	-1.3
Closing MAB	57.7	53.7	51.3	48.9	48.0
Opening MAB as at 1 July 2026					**48.0**

Source: *JEN - Att 10-04M ACS Metering RFM - 20250131.*

The components in Table 4-1 have been sourced as follows:

- The opening value of the MAB for FY22 is based on the closing of the June 2021 value from the AER's final decision on the AMI transition charges application.
- The forecast closing MAB on 30 June 2026 is our forecast opening MAB on 1 July 2026, which is $48.0 M[17]

17 *See JEN - Att 10-04M ACS Metering RFM - 20250131.*

- The indexation is based on actual inflation
- The capital expenditure used in the roll forward model is our actual for FY22 to FY24 and our forecast for FY25 and FY26. In our revised regulatory proposal, we will replace our forecast capital expenditure for FY25 with our actual FY25 capital expenditure.

The straight-line depreciation is based on our forecast capital expenditure in the current regulatory period.

4.2 Forecast metering asset base to 30 June 2031

We have taken the opening MAB as at 1 July 2026 and rolled it forward for each regulatory year of the next regulatory period using the AER's PTRM. This approach involves:

- adding forecast indexation
- adding forecast capital expenditure
- depreciation
- deducting proceeds from asset disposals.

Table 4-2 details the calculation of our forecast opening and closing MAB for the next regulatory period.

Table 4–2: Forecast MAB ($ Nominal, millions)

	FY27	FY28	FY29	FY30	FY31
Opening MAB	48.0	57.7	70.4	83.9	101.9
Inflation on opening MAB	1.2	1.4	1.8	2.1	2.5
plus capital expenditure	15.4	19.9	22.2	28.4	30.1
less straight-line depreciation	-6.8	-8.7	-10.5	-12.6	-15.5
Closing RAB	**57.7**	**70.4**	**84.0**	**101.9**	**119.0**

Source: *JEN - Att10-02M ACS Metering PTRM 20250131.*

5. Our smart metering capital expenditure

Metering capital expenditure relates to augmentation and replacements of JEN's AMI assets. AMI assets comprise meters, a propriety communication network which includes a head-end network management system (**NMS**) and related back-end IT systems.

5.1 Our technology solution

5.1.1.1 Our AMI meter solution

JEN manages approximately 387,000 Victorian AMI functionality-compliant meters installed at its customer installations. JEN has established a multiple meter supplier model to ensure the reliability and security of meter supply. Our metering assets include:

- Direct Connected Meters (AMI and legacy)
- CT-connected Meters (AMI and HV meters).

JEN meters provide the following capabilities:

- Metering of main and auxiliary supply
- Power quality
- Remote control of main and auxiliary loads
- Customer connections neutral integrity.

5.1.1.2 Our AMI communications network

The JEN communications network provides the two-way connectivity platform between metering endpoints in the RF Mesh Network and the back-office NMS. Communications devices (Access Points, Relays and Next G backbone platform) are crucial in managing data traffic between downstream devices (Meters, Smart sensors, etc.) and the backend systems.

The AMI mesh network operates on the 915-928 MHz unlicensed bandwidth, it is based on IPv6, IEEE 802.15.4g, and Wi-SUN compatible. Currently, JEN manages approximately 584 communication devices within JEN's electricity network, enabling communications between AMI meters and the NMS.

Electricity measurement communications assets must:

- Ensure communications availability for all metering and network management communications, enabling new connections and abolishment/alterations
- Be economical to purchase and maintain
- Support supply investigations; and
- Prudently support future customer experience pathways ('advanced services').

5.1.1.3 Our NMS

JEN collects meter data from AMI meters via the AMI communication network, and the data enters our back-end IT system via the head-end product known as NMS. We then use a suite of products, collectively called the Meter Data Management systems, to validate that metering data is managed in accordance with AEMO's metrology procedures and deliver it to the various market participants.

5.1.1.4 Leveraging our technology for continuous improvement

JEN is continuing to develop and enhance its utilisation of the AMI communications network for advanced network monitoring and management functions. This includes localised and area power outage monitoring and detections, customer site and service safety monitoring and mitigations, network and power supply quality and distributed generation management.

5.2 Our investment drivers and volumes

5.2.1 Metering investment drivers

The following drivers drive our metering investment:

5.2.1.1 Lifecycle replacements

In the next regulatory period, the most significant driver for our metering capital expenditure is the replacement of JEN's aging smart meters. JEN's current generation of AMI meters were installed between 2009 and 2013, as shown in Figure 2–1. These were designed for a 15-year operational life. So many of them are now reaching the end of their technical life. This is when their failure rates are expected to rapidly increase in line with the commonly seen bathtub curb.[18]

Our analysis of the failure rate trends shows we need to replace 22% of our total AMI meters in the next regulatory period. If not replaced, we expect a large majority of these aged meters to fail by 2031 critically affecting ability to meet our metrology obligations and triggering a disorderly mass replacement program within mandated replacement times for in field meter failures.

Box 5.1 | Smart meter aged failure experience of other early smart meter deployments

Distributors in Canda[19] and Italy[20] who commenced their first generation smart meter deployments ahead of Victoria's in 2007 and 2008 respectively have already commenced their smart meter end of life replacements.

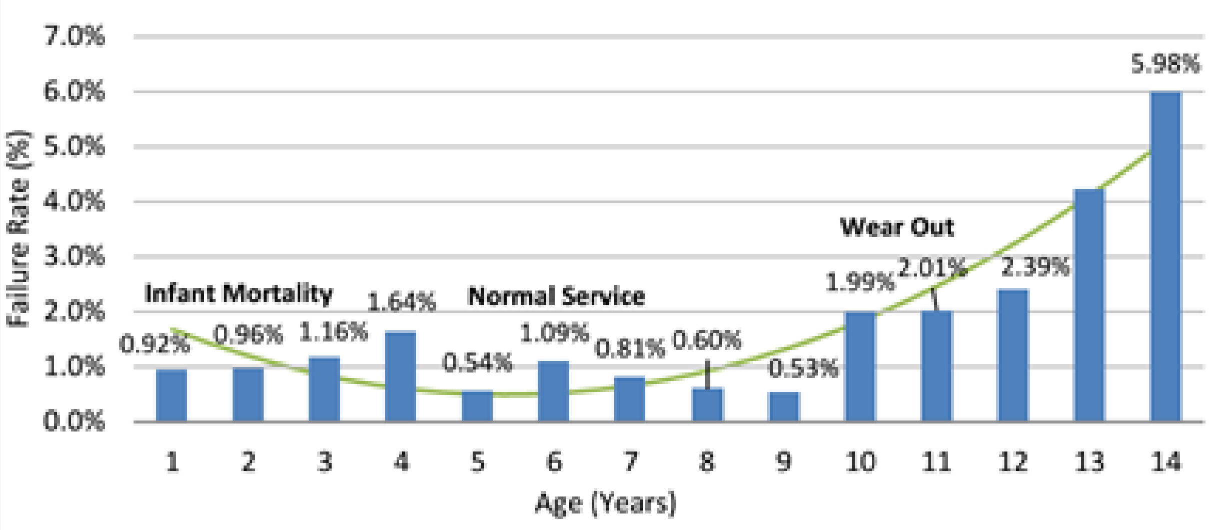
In proposing its meter replacement program back in 2021, Canadian distribution network business Hydro One provides data on the rapid end of life increase in smart meters in years 13 and 14 of their 15 year design life as shown below.

18 See Ignoring a bath curve is a slippery slope | Energy Networks Australia, 18 Mar 2021.

19 Hydro One Networks Inc. (Hydro One), Distribution System Plan for the 2023 to 2027 period – Exhibit B-3-1 Section 3.0, 5 Aug 2021.

20 Smart Energy International, Italy's SET Distribuzione launches second-generation smart meter programme, 22 Sep 2021.

Figure 5–1: Canadian first generation smart meter failure data by meter age as of 2020



Source: Hydro One Networks Inc. (Hydro One), Distribution System Plan for the 2023 to 2027 period – Exhibit B-3-1 Section 3.0, 5 Aug 2021, Section 3.2 Figure 75 p.97.

This trend of failure before the end of the design life is exacerbated by technical obsolescence in the first generation smart meters and their electronic componentry. The Ontario Auditor General, in its report on Ontario's smart meter initiative, found a 15-year service life estimate for meters is likely overly optimistic given technological obsolescence considerations.[21]

Being semiconductor-based electronic equipment, our AMI meters have a shorter life than conventional electromechanical meters. They also exhibit more abrupt failure modes (i.e. such equipment and componentry works well until total failure, unlike conventional meters that gradually lose accuracy). Factors contributing to this pattern of failures include that:

- The lithium-ion battery installed inside every AMI meter is non-rechargeable and was designed for a 15-year service life, under "normal supply" operation. However, the life of the meter battery is significantly reduced by the "off supply" time and the ambient temperature of the meter surroundings.
- It is not uncommon that meters installed inside a metal meter box under direct sunlight will be subjected to operating temperatures more than 60-70ºC. High ambient temperature degrades many semiconductor components in the meters.
- The memory chips used in AMI meters are designed for a finite number of write and read cycles, which presents the possibility of correlated failures of meters deployed in the same year the risk of which is exacerbated by 78% of JEN's current smart meters having been all installed between 2009 and 2013.
- Correlated failures risk is further compounded by the fact that all AMI meters in Victoria are produced by the same two manufacturers and were installed within the same timeframe.

The communication module of the AMI meters uses the same AMI mesh network interface cards (**AMI NICs**) across all AMI meters in Victoria, which is also (separately) designed for an expected 15 year service life.

The risk of concurrent meter failures and excessive costs of replacing the meters under such scenarios is significant. JEN (and the Victorian industry) is neither well positioned to be agile in mounting large meter replacement programs in response to concurrent failure of large numbers of meters (e.g. meter family failures), nor would such a disorderly replacement approach be consistent with the least cost. Moreover, the NER

[21] Auditor General of Ontario, 2014 Annual Report of the Auditor General of Ontario, 2014, p. 391.

prescribed replacement timeframes which are as soon as practicable and no later than 10 business days after JEN has been notified of malfunction[22] for meters that do fail are much more onerous and therefore costly, than where replacements are proactively managed in an orderly fashion.

AMI meters and AMI NICs have long procurement lead items with a relatively short (5-year) manufacturer's warranty making holding large inventories undesirable. JEN's recent experience shows that the current lead time is up to 12 months, and JEN's supplier requires an advance forecast for production capacity planning.

To mitigate these risks and enable efficient replacement of the AMI meters installed en-masse during the 2009-2013 period, a proactive condition-driven meter replacement program is proposed to optimise the costs of proactive replacement with JEN's 15 year meter physical inspection obligations. This co-optimised program prudently leverages our required metering installation inspection program, where meters that are found to be in poor state are proactively replaced in lieu of inspections during the inspection process.

Our replacement forecasts include the expected increase in supply upgrades from single to three-phase meters that we anticipate driven by electrification and the Victorian government ban for new residential gas connections.[23] Whilst we do not plan to replace all our AMI meters on their 15th anniversary, we expect that a portion of these meters will be replaced, and we intend to replace those as part of the meter inspection program, prioritising meters that exhibit signs of excessive wear and tear and/or produced measured technical indicators that the meters are no longer complaint (e.g. failed battery, LCD, damaged terminals). This approach will help identify and prioritise the meters most likely to fail while confirming the compliant operation of the remaining fleet of aged meters, thereby allowing us to minimise the number of required replacements.

JEN has developed an AMI meter inspection and replacement business case.[24] This business case also explains options we considered including testing if component replacements were feasible. A summary of the component replacement option considerations is provided in Box 5.2 below.

Box 5.2 | Replacement of meter components versus the whole meter

Replacing components of a meter as compared to the whole meter would not be a viable option given the cost of labour involved in the process of replacing part of it is significantly higher than the costs of the meter unit itself:

Total cost = cost of meter removal + cost of meter repair + cost of the failed component (varies depending on component) + costs of meter re-verification + costs of meter redeployment

In addition, a failed component represents the lead indicator of the deteriorated condition of the meter in that metering installation. That is, a failed meter component is likely to be the first indicator of the deteriorated condition of the overall meter installation, with the likelihood of failures in other components to follow suit. Replacing a failed meter component is not likely to significantly extend the expected residual life of the meter. Therefore, it is more efficient to replace the whole meter unit instead of the components that have failed.

Table 5-1 sets out our proposed forecast conditioned-based meter replacement volumes:

Table 5–1: Proactive (condition-based) replacement volumes by year

	FY27	FY28	FY29	FY30	FY31	Total
Lifecycle replacement meter volume	1,910	11,460	19,101	22,921	26,741	**82,133**

Source: *Att 10-03M ACS Metering opex and capex model FY26 – 31*.

[22] NER Clause 7.8.10(a)(3). Refer Box 5.3 below.

[23]. Victoria's Gas Substitution Roadmap

[24] *JEN - RIN - 4.6.1 - Business Case - Inspection of Metering Installations - 20250131*

5.2.1.2 Faulty meter replacements

In addition to our proactive replacements, the scale and age of our meter fleet mean JEN will continue to see a level of meter failures from its AMI meters that are in service. Our forecasts of the volumes of such failures informed by Frontier Economics' analysis[25] of our failure rate trends and the impact of our co-optimised inspection and proactive replacement program.

Absent our proactive lifecycle replacement program being delivered concurrent with our inspection program, we expect the reactively reported in-service meter failure volumes to be significantly higher than presented in Table 5.2 climbing to 8.11% of meters in FY31, giving a cumulative failure figure of 22% over the next regulatory period. This would significantly impede our ability to comply with prescribed AMI performance obligations and to meet our replacement obligations for meters that malfunction whilst in service (see Box 5.3).

Table 5-2 sets out our proposed forecast meter failure replacement volumes.

Table 5–2: Reactive meter replacement volumes by year

	FY27	FY28	FY29	FY30	FY31	Total
Faulty replacement meter volume	1,294	1,582	2,093	2,981	4,549	**12,499**

Source: *Att 10-03M ACS Metering opex and capex model FY26 – 31*.

Box 5.3 | Our obligations if a meter fails in the field

What is the obligation?

Victorian DNSPs face a more onerous fault meter replacement obligation of 10 business days for repair or replacement than the 15 business days for other NEM metering service providers.

How does this difference arise?

NER 7.8.10(a)(2)(i) requires notified meter malfunctions to be repaired within 15 business days for a 'metering installation at a small customer's premises'. However, a 2017 Ministerial Order under section 16BA of the Victorian National Electricity (Victoria) Act 2005 varies application of the NER in Victoria. Specifically, among other things, this order disapplies the NER clauses for small customer metering. This makes JEN's metering obligations as regards malfunctioning Victorian AMI meter installations those in NER 7.8.10(a)(3)(i) for other metering installations, which requires 10 business days from the malfunction notification.

In total, JEN forecasts using its own linear extrapolation of failure rates that 22% of our AMI meters will need to be replaced by the end of next regulatory period (comprising both proactive and reactive replacements). The 22% forecast is informed by:

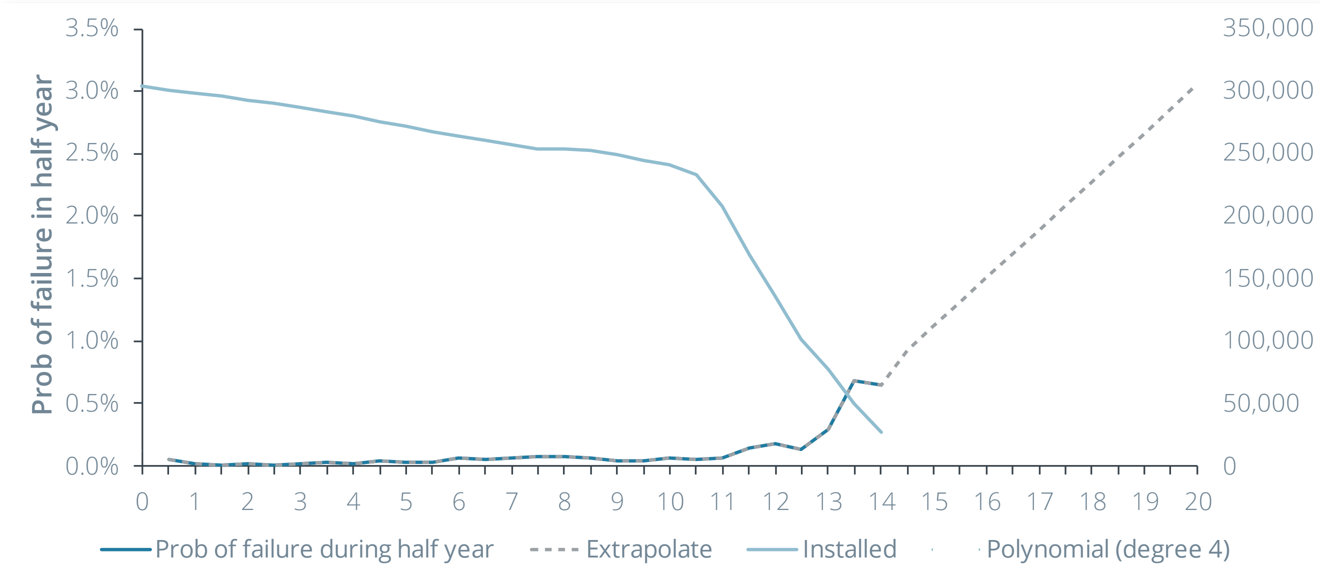
- JEN's observed growth in the rate of meter failures and associated analysis shown in Appendix D of the meter inspection and replacement business case *JEN - RIN - 4.6.1 - Business Case - Inspection of Metering Installations - 20250131.*
- An expected increase in failures when JEN starts inspections of 15-year-old Vic AMI meters
- Review of local and international experience (see Box 5.1) and discussions with meter manufacturers and other Victorian Distribution Network Service Providers (**DNSP**s) who have equivalent AMI meters

[25] *JEN - Frontier Economics Att 10-07 - Forecast replacement of smart meters - 20241220*

- JEN commissioned study by Frontier Economics, delivering a detailed quantitative projections of failure rates and maximum acceptable failure rate levels for JEN to be able to comply with its obligations.

Notably, using more sophisticated statistical techniques than our internal extrapolations, Frontier Economics projects that by the end of the next regulatory period we will need to replace a minimum of 115,442 (27% of JEN meters population) for JEN to meet its metering performance obligations. We outline the projected meter failure rates in Figure 5–2 below.

Figure 5–2: Analysing JEN's failure rate trends



Source: Frontier Economics

Notwithstanding this higher forecast from Frontier Economics, we have retained our projections for the purpose of this proposal.[26]

5.2.1.3 Connections

Our forecasts of AMI meter volumes for new connections are based on JEN's historical trend and applying our forecast customer growth rate.[27] The independence and expertise of Blunomy, who prepared our demand forecasts, ensures transparency and robustness of our forecasted volumes.

Consistent with the economy-wide transition to greater electrification of homes, businesses and cars, and in light of Victoria's ban on gas connections to new buildings, our developer customers are currently requesting 3 phase meters as the default for new connections. JEN has therefore forecast 3 phase meters for all new connections.

Table 5-3 sets out our proposed forecast conditioned-based meter replacement volumes:

[26] JEN has just completed 2024 which is the first full year that the original 5% of meters deployed in 2009 as first generation AMI meter will have turned 15 years old. With the benefit of this data and data received as they turn 16 years in 2025, we will review the experienced failure rates and account for these in our revised regulatory proposal should they prove to be closer to the Frontier Economics projections.

[27] See Attachment 05-04.

Table 5–3: New connection volumes by year

	FY27	FY28	FY29	FY30	FY31	Total
New connections volume	9,387	9,560	9,730	9,901	10,072	**48,650**

Source: *Att 10-03M ACS Metering opex and capex model FY26 – 31*.

5.2.1.4 Additions and alternations

Forecast of AMI meter volumes for alterations and refurbishments are based on JEN's historical trend and applying our forecast customer growth rate. Table 5-4 sets out our proposed forecast meter alteration and addition volumes:

Table 5–4: Alterations and refurbishment volumes by year

	FY27	FY28	FY29	FY30	FY31	Total
Alterations (meters installed and removed)	1,192	1,213	1,235	1,257	1,278	**6,175**
Abolishment	2,329	2,371	2,414	2,456	2,499	**12,069**
Refurbishment	1,867	1,995	2,131	2,277	2,433	**10,703**
Total	**5,388**	**5,579**	**5,780**	**5,990**	**6,210**	**28,947**

Source: *Att 10-03M ACS Metering opex and capex model FY26 – 31*.

5.2.2 ICT investment drivers

5.2.2.1 Augmentation of our AMI communication network

As our customer base and market and regulatory data requirements grow, we need to augment the AMI communication network to ensure our metering communication capabilities grows to provide coverage, data throughput and capacity requirements. This augmentation involves adding access points, relays, antennas, and dedicated poles to which AMI communication components are attached.

We have forecast capital expenditure for the augmentation of our AMI communication network to support the forecast growth of new connections as well as demands for additional data and networks monitoring and management capabilities over the next regulatory period using our forecast customer growth rate and our current contracted unit rates for the procurement and installations of our AMI communication network equipment.

5.2.2.2 Lifecycle replacements of batteries in our AMI communication network

Our AMI communication network equipment requires periodic lifecycle renewal of batteries in the access points and relay equipment to ensure capacity, performance and reliability are maintained in line with our obligations under the AMI functional specification order in council. Our lifecycle forecasts allow for risk-based replacements of AMI communication assets through the period.

Access points and relays need batteries so they can continue to operate during a power outage. These batteries have a service life of five years and must be replaced at the end of their service life. Accordingly, we have forecast cyclical replacement of battery packs in the access points and relays.

5.2.2.3 Lifecycle management of our network management system

The stability of our metering network management system is important in allowing us to continue delivering safe and efficient metering services to customers from delivery of the energy consumption data to our customers to providing them insights on their electricity usage as well as the capability to monitor and manage our customer connections to ensure reliability and continuous supply.

JEN collects meter data from AMI meters via the AMI communication network, and the collected data enters our back-end IT system via the NMS. We then use a suite of products collectively called the Meter Data Management systems to validate metering data in accordance with AEMO's metrology procedures and deliver it to the market (AEMO and retailers) to calculate and recover network charges. We also use other connection points' status and power quality data collected by the meters to assess and manage any connection and network issues.

These systems, including the network management system, all have a finite expected useful life and periodically require maintenance, testing, and upgrading, in accordance with the application manufacturer guidelines and recommendations, to ensure JEN can continue to provide services as obligated under Victoria's AMI functional specification and national metrology procedures and as expected by our customers.

JEN's IT applications are subject to regular review to assess whether they maintain fit for purpose as evaluated against a range of criteria, including performance, security, cost-effectiveness, serviceability, end-of-life timeframes and overall risk. These systems are reaching an unacceptable level of support risk at various times during the next regulatory period. We also make decisions to replace these systems by taking into account the optimum time for an upgrade or replacement based on the historical performance and serviceability of the components and interdependent systems and processes.

Table 5-5 shows the IT project capital expenditure for the lifecycle upgrade.

Table 5–5: Lifecycle upgrade ($ June 2026, millions)

	FY27	FY28	FY29	FY30	FY31	Total
Lifecycle upgrade	2.19	-	-	2.19	-	4.38

Source: *JEN - Att 10-03M ACS Metering opex and capex model - 20250131*.

5.2.2.4 ICT systems capacity enhancement

We propose changes to our systems in order to support the large-scale meter inspections and replacements program during the next regulatory period. This involves enabling the auto close out function of new scenario build, including meter modification updates to be uploaded onto our systems. Our forecast costs for this activity include testing for:

- New order type
- New activity types
- Maintenance plan configuration/creation (multiple - cycles) by installation date
- Order create/processing workflow change
- Order auto-create/release via plan
- SAP download order change
- Order completion process
- New measurement documents/points for test points/results
- Placeholder for any additional minor changes.

Table 5-6 shows the capital expenditure for auto close-out functionality.

Table 5–6: Changes and mobility solution for inspections and replacements ($ June 2026, millions)

	FY27	FY28	FY29	FY30	FY31	Total
Changes and mobility solution	0.7	0.7	-	-	-	1.4

Source: *JEN - Att 10-03M ACS Metering opex and capex model - 20250131*

5.3 Our procurement approach

JEN's procurement strategy and process align with our overall asset management strategy and vision to deliver optimal value for money and maintain an efficient procurement system. These practices are built on solid business risk management principles. The key elements of our procurement approach include:

- Regularly running open market tender processes for technologies that have a multi-vendor market and offer interoperable products
- Ensuring product specifications meet current and anticipated regulatory requirements, including mandated programs such as the AMI Orders in Council issued by the Victorian Government
- Proactively addressing advancements in metering technology by adopting cost-effective strategies to minimise the risk of obsolescence, reduce the need for future asset upgrades, and support efficient lifecycle management
- Providing customers with technologies and insights into their energy consumption (either in real-time or periodically) to encourage improved energy usage practices.

Currently, our AMI meters are procured through a contract established via an open market tender process. The unit rate prices for the metering communication network components are procured from the vendor.

5.3.1 Capital expenditure forecasting method(s)

The section below describes how we forecast our capital expenditure in Attachment 10-02M.[28]

AMI meters

The forecasted capital expenditure for AMI meters is calculated as the sum of meter costs (labour and non-labour components):

- The labour component is calculated by multiplying total meter volumes (new connections, alterations, failures/faults and replacements) by the total independent benchmarked labour costs for carrying out those metering activities, with lower labour effort assumed for meters deployed under the proactive AMI sections and replacement program. The labour rates are escalated annually for labour escalators forecast by BIS Oxford Economics.[29]
- The non-labour component is calculated by multiplying total meter volumes by the unit cost of AMI meters, which was established through JEN's most competitive tender process.

AMI communications network

The capital expenditure forecast for AMI communication network is based on the forecast volumes of communication components required to meet the growth of customer connections, replace batteries, replace communication equipment as they approach the end of their technical life and address anticipated equipment failures.

28 *See JEN - Att 10-02M ACS Metering PTRM - 20250131.*

29 Provided as Attachment 05-07.

For each replacement communication equipment type we adopt a different approach to end-of-life management to minimise lifecycle cost:

- Access points and relays are replaced at the end of their 7 year technical life
- Batteries have a 5 year life.

We multiply the forecast volumes of the communication network components by unit rates which are based on the process of the components and independent benchmarked labour costs (as discussed in section 5.3).

NMS

The capital expenditure forecast for our NSM is based on infrastructure lifecycle replacement and forecast application upgrades as follows:

- Infrastructure – All NMS infrastructures and related management systems hardware are maintained in external Tier 1 data centres and their performance is monitored and managed in accordance with Tier 1 data centre management requirements and processes (e.g. dedicated infrastructure with 99.671% uptime).
- Application—JEN's dedicated digital support team monitors NMS application performance. Application performance and capabilities are reviewed annually and upgraded as required and mandated under the application support and licence agreement with the application vendor.

Network overheads

Consistent with the approach for the current regulatory period and in accordance with our AER-approved Cost Allocation Methodology, network overheads are assumed to be zero. This is because no network overheads are allocated to ACS metering activities.

Equity raising costs

Equity raising costs are calculated using the AER's PTRM model once all inputs have been included.

5.4 Our capital expenditure forecast

Table 5-7 sets out our proposed forecast metering services capital expenditure for the next regulatory period. It represents the prudent and efficient costs required to provide ongoing smart meter services to our customers.

Table 5–7: Forecast capital expenditure ($ June 2026, millions)

Category	FY27	FY28	FY29	FY30	FY31	Total
Remotely read interval meters & transformers	6.6	12.0	16.6	19.4	22.7	77.2
IT	0.1	0.3	0.3	0.4	0.5	1.7
Communications	2.3	3.2	3.4	3.3	2.9	15.1
Other	2.4	2.4	-	-	-	4.9
Inhouse Software	2.9	0.7	-	2.2	-	5.8
Equity raising costs[30]	0.4					0.4
Total	**14.7**	**18.6**	**20.3**	**25.3**	**26.1**	**105.1**

Source: *Att 10-02M ACS Metering PTRM FY26-31*.

5.4.1 Our capital expenditure is efficient

JEN's asset management and procurement practices combine to ensure our capital program costs are both prudent and efficient. JEN maintains ISO 55000 accreditation which the AER's capital expenditure incentive guideline identifies as a means for DNSPs to demonstrate:

- Appropriate project management plans and processes including asset management, project delivery controls, procurement strategies, asset lifecycle management, resourcing strategies, program management and risk management
- Appropriate project governance and capital governance.[31]

Table 5-8 sets out how we ensure the costs used in preparing our forecasts are efficient.

Table 5–8: Sourcing efficient cost inputs

Cost type	Source of cost
Labour rates	Based upon independent benchmarks
Metering equipment unit cost	Derived directly from competitive tender processes
Metering communication equipment cost	Based upon estimates obtained from contractors or manufacturers
ICT systems capacity enhancement cost	Based upon competitive tender processes for similar projects

We believe our capital expenditure for procurement and installation of AMI meters and enabling communication network is efficient because:

- The forecast of AMI meter volumes for new connections is based on JEN's historical trend and applies Blunomy's forecast customer growth rate. Blunomy's independence and expertise ensure the transparency and robustness of our forecasted volumes.

30 See Attachment 10-04M

31 AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, April 2023, p.14.

- meter installation costs for new connections, alterations and refurbishments are funded through relevant fixed-fee ACS charges and hence not included in the shared AMI capital forecast
- installation labour unit rates are based on independent benchmark rates. Our methodology follows Marsden Jacob's approach to setting the labour rates for ancillary network services as part of its report to the AER in June 2020.[32] The AER has since adopted Marsden Jacob's recommended approach during the 2021 electricity distribution price review for the Victorian DNSPs and in its most recent price determination for New South Wales DNSPs. The base salary used in the labour rate calculation is based on Hays 2024-25 published salary guide and the escalator used for wages are based on Bis Oxford Economics forecasts
- installation costs for metering communications are based on independent benchmarked labour unit rates (described in the dot point above) and effort provided by JEN's contractors
- ICT systems capacity enhancement costs are based upon JEN's competitive tender processes for similar projects
- JEN is co-optimising physical meter inspections (operating expenditure) and replacement activities (capital expenditure) as detailed in RIN-4.6.1.

5.5 Our capital expenditure plan is supported by our Energy Reference Group

In its response to our Draft Plan, our ERG supported our co-optimised approach to jointly meeting our aged meter inspection obligations whilst proactively replacing first-generation smart meters that are found to be high failure risk. The ERG stated:

> *The Energy Reference Group support the strategic replacement of ageing Advanced Metering Infrastructure (AMI) meters and the extension of replacement timeframes to ensure prudent use of resources. We find the proposed approach to meter replacement both reasonable and well-structured. Aligning in-person inspections with meter replacements is deemed highly efficient, and we appreciate the proactive stance on maintaining compliance with new smart meter inspection obligations.*[33]

The ERG went on to make the further items of feedback summarised in Table 5-9, in which we show how we have responded to each item in this proposal.

Table 5–9: ERG Draft Plan metering feedback

Feedback item	How our proposal responds
Communicating JEN's approach | We also stress the importance of clear communication with the community to alleviate any concerns regarding the meter replacement process. It is crucial to outline the issues, present viable alternatives, and explain the rationale behind the chosen approach to maintain public trust and support.	Our business case[34] for age-based inspections and replacement option assessment incorporates a communication plan.
3-phase meter upgrades | Furthermore, we recommend a clear alignment of the meter replacement timelines with the three proposed electrification scenarios (High, Medium, Low) and the corresponding upgrades to 3-phase power necessary for increased demand from induction cooktops and electric vehicle chargers.	Whilst there would be some efficiency in coordinating an individual's customer upgrade with the timing of the roll-out, there is little chance of this occurring as the coincidence of the timing of the customer need with the optimised rollout program would need extensive cooperation of client-side activities (for example, electricians installing new appliances). This level of collaboration would be disruptive and would be more costly for all customers. To improve efficiency and customer equity, we will address customer needs to install a three-phase supply (and therefore three-phase metering) at the time the customer seeks an upgrade

32 *JEN - Att 11-03M 2024-25 ACS Labour rate mode.*

33 *JEN - Att 02-23 Energy Reference Group Report*, Feedback on Jemena's 2026-2031 draft plan, 2024, Pg 21.

34 JEN – *RIN – 4.6.1 – Inspection of Metering Installations – Business Case.*

Feedback item	How our proposal responds
	and charge the requesting customer for this increased level of services. The alternative of pre-emptively upgrading supply at the time of the rollout will be more costly and less equitable.
Customer Communication and Scheduling | It is important to give every customer forewarning of the upcoming metering upgrade and the opportunity to reschedule. This will allow customers to combine the truck visit with any planned electrical upgrades, such as moving to three-phase to install a premium induction hob.	Customer notifications are delivered via multiple methods: Emails, letter or card drops or phone communications to organise appointments. Customer communications commence for any planned works at the customer site that may lead to customer supply being disrupted. There are specific timeframes that set mandatory notification periods. Planned interruptions require a minimum 4 business days written notice (hard copy or electronic form) for non-life support customers and a minimum 4 business days written notice for life support customers with additional time if specified by the customer.[35] Additional notification of one business day prior to the interruption is required if notification is done electronically.
Data Security and Privacy | Smart meters capture vast amounts of data. While this data supports valuable products and services, it is crucial to ensure that customer privacy is maintained. We recommend addressing potential data security risks and taking steps to ensure compliance with privacy regulations.	JEN is obligated to ensure its fully complies with data protection and privacy requirements. JEN holds and handles customer personal information and consumption data which are both sensitive in nature and JEN has processes and procedure in place which define and control how the data is kept, handled and disposed of. JEN has an established data security platform implementing ISO 27001 security frameworks.
Cost Transparency | While the overall revenue requirement is forecast to decrease, it is essential that the associated costs of smart meter services are transparent to customers. Ensuring clarity on how price reductions will be reflected in customer bills will help build trust.	This attachment provides our full cost breakdown for our ACS metering charges, and is supported by our ACS metering PTRM available at Attachment 10-02M. JEN does not control how Victorian retailers pass on our charges, however through setting the annual Victorian Default Offer, the Essential Services Commission will adjust the capped retail offer for customers in our network area at an amount that accounts for changes in our metering costs.
Customer Experience during Meter Replacement | As ageing AMI meters are replaced, there may be interruptions in service. It is vital to inform customers about the process and minimise disruptions, particularly with the recent rise in people working from home. Clear communication should be prioritised to avoid confusion.	JEN's notifications are administered in accordance with our obligations in the EDCoP which among other things include requirements for unplanned outage notifications to be: – Notified at least 4 business days prior – In each customers nominated preferred communication format (i.e. writing, electronically or both) – In plain English – With details for them to contact us We also have separate obligations for life support customers.
Future-proofing Smart Meters | With the rapid advancement of technology, it is important to ensure that the new smart meters are future-proof. They should be adaptable to upcoming technologies or standards to avoid frequent replacements.	JEN will install our second generation of smart meters that meet the current Victorian functional specification. JEN and other Victorian DNSPs are working actively with DEECA to ensure this specification remains current for emerging market needs.
Data Governance and Efficiency | Data governance related to AMI meter data and other network data is under represented in the current documentation. We recommend including an assessment of the increase in efficiency,	JEN will uplift its JEN's Data Governance and Efficiency relating to AMI meter data as well as other data sources as part of the Data Visibility and Analytics Program within JEN's Future Network Strategy.

35 ESC, *Electricity Distribution Code of Practice (EDCoP)*, clause 11.5, May 2023.

Feedback item	How our proposal responds
particularly regarding CER management through enhanced data insight capabilities.	The existing network analytics prototype platform will be replaced by a Data Hub that includes a management layer for data governance, access control, security, performance monitoring

6. Pricing

6.1 Smart metering prices

We propose to continue setting separate prices for our four meter types for the next regulatory period. The charge types are consistent with the previous regulatory period and the current regulatory period. The benefit of continuing with the four charge types is that IT billing systems do not have to be changed and retailers and customers are familiar with the four charge types. There has not been any new information that warrants changing to an alternative approach.

To determine smart metering prices we apply the price control formulae.[36] We have applied the revenue cap formula and inputs set out in the previous sections to calculate metering charges for the next regulatory period. The key inputs—as described in price control formula and calculated using the metering PTRM—are:

- the smoothed annual revenue requirement for the first regulatory year of the next regulatory period
- the real price movement in the annual revenue requirement (x-factors) for setting prices in the remaining regulatory years of the next regulatory period.

Table 6-1 shows our indicative metering charges for the next regulatory period.

Table 6–1: Proposed indicative metering charges per meter, per year ($ June 2026, millions)

AMI meter charges (<160 MWh per annum per meter)	FY26	FY27	FY28	FY29	FY30	FY31
Single-phase non-off peak per meter per annum	62.03	62.00	62.00	65.47	69.13	72.99
Single-phase off-peak per meter per annum	62.03	62.00	62.00	65.47	69.13	72.99
Multi-phase direct connect per meter per annum	75.73	75.69	75.69	79.93	84.40	89.12
Multi-phase CT per meter per annum	84.35	84.31	84.31	89.02	94.00	99.26

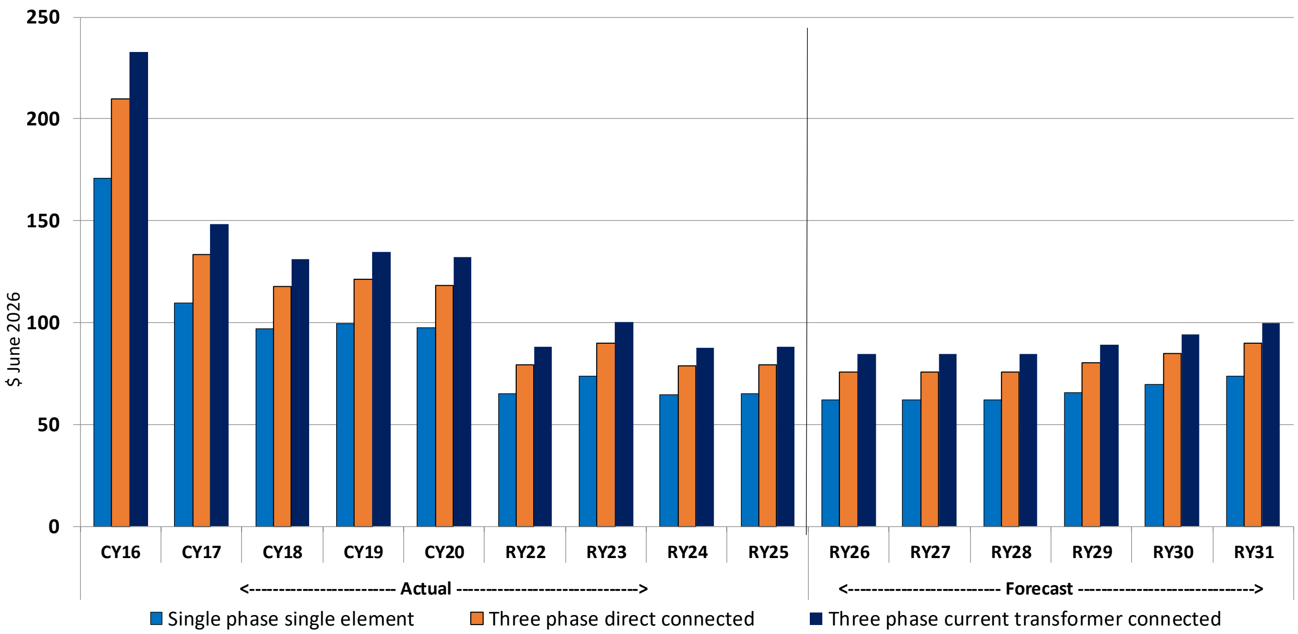
Source: *Att 10-02M ACS Metering PTRM FY26-31 – 20250131.*

These prices are indicative only, and actual prices may vary because of a number of factors, including under or over collection of revenue from year to year, or some tariff rebalancing. Prices will be submitted to the AER for its consideration and approval as a part of the annual pricing approval process.

Figure 6-1 shows the historical and forecast trend in JEN's metering charges.

36 See Attachment 04-02.

Figure 6–1: Metering charges per annum ($ June 2026)



Further, analysis of the three options in AMI meter inspections and replacements business case[37] shows that our proposed option (Option 2) of co-optimising our inspection and replacements supports the lowest AMS metering prices. This can be seen by the indicative metering charges for the other options considered in the business case (shown in Table 6-2 and Table 6-3), which are higher than those JEN is proposing (shown in Table 6-1).

Table 6-2 shows our indicative metering charges using option 1 for the next regulatory period. This option involves conducting the prescribed age-based metering inspections of every installation in operations and only reactive replacement of faulty meters.

Table 6–2: Indicative metering charges per meter, per year ($ June 2026, millions)-Option 1

AMI meter charges (<160 MWh per annum per meter)	FY26	FY27	FY28	FY29	FY30	FY31
Single-phase non-off peak per meter per annum	62.03	62.00	62.00	69.76	78.49	88.31
Single-phase off-peak per meter per annum	62.03	62.00	62.00	69.76	78.49	88.31
Multi-phase direct connect per meter per annum	75.73	75.69	75.69	85.17	95.83	107.82
Multi-phase CT per meter per annum	84.35	84.31	84.31	94.86	106.73	120.09

Table 6-3 shows our indicative metering charges using option 3 for the next regulatory period. This option only replaces all meters requiring inspection. No age-based site inspections are carried out under option 3.

Table 6–3: Indicative metering charges per meter, per year ($ June 2026, millions)-Option 3

AMI meter charges (<160 MWh per annum per meter)	FY26	FY27	FY28	FY29	FY30	FY31
Single-phase non-off peak per meter per annum	62.03	62.00	62.00	67.83	74.20	81.17

[37] JEN, *Inspection of Metering Installation Business Case*. See RIN-4.6.1.

AMI meter charges (<160 MWh per annum per meter)	FY26	FY27	FY28	FY29	FY30	FY31
Single-phase off-peak per meter per annum	62.03	62.00	62.00	67.83	74.20	81.17
Multi-phase direct connect per meter per annum	75.73	75.69	75.69	82.74	90.43	98.85
Multi-phase CT per meter per annum	84.35	84.31	84.31	92.15	100.72	110.09

6.2 Revenue path

As demonstrated in Table 6–4 our forecast smoothed and unsmoothed revenue over the next regulatory period has the same net present value (**NPV**) demonstrating that our building block proposal does not over-compensate us because of smoothing.

The smoothed revenue profile is calculated using the AER's PTRM (by making smoothed revenues equal to required (i.e. unsmothered) revenues in net present value terms) and is summarised in Table 6-4.

Table 6–4: Proposed Alternative Control Services revenue and revenue path ($ June 2026, millions)

	FY27	FY28	FY29	FY30	FY31	NPV
Unsmoothed revenue requirement	22.4	24.6	28.3	30.8	33.2	125.0
Smoothed revenue requirement	25.0	25.5	27.4	29.4	31.6	125.0
Revenue path change (% pa) (1)	**1.7%**	**1.8%**	**7.5%**	**7.4%**	**7.4%**	**N/A**

(1) Relative to FY26 revenue.

Source: *Att 10-02M ACS Metering PTRM FY26-31 – 20250131.*

6.3 Revenue cap for smart metering services

We propose to apply the revenue cap form of control to annual metering charges as outlined in our price control proposal.[38] Under this form of price control, our annual AMI revenue is capped for each year of the next regulatory period and any under or over recovery of actual revenue collected in a regulatory year being trued-up—along with time value of money adjustment—in subsequent regulatory years.

We outline the revenue cap pricing formula we propose in section Attachment 08-01.

6.3.1 Metering pass-throughs

We note that the AER's revenue cap formula for the current period and that proposed in its framework and approach for the next period include a pass-through mechanism. Specifically, it states that:

> *C_t is the approved metering pass-through amounts (positive or negative) for year t, as determined by the AER. It will also include any annual or end of period adjustments for year t. To be decided in the distribution determination.*[39]

The pace of technology and regulatory change affecting JEN's metering fleet has increased significantly as a result of numerous rule changes seeking to:

- Empower customers with real-time data access and regulate how this is provided
- Adapt the functionality required for integrating various forms of CER and DER
- Manage the low voltage power system consequences of system minimum demand

38 See Attachment 04-02.

39 AER, *Framework and Approach AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026-31*, July 2024, p.13.

- Implement new AEMO guidance for metering asset management plans.

While it is not possible to foresee all of these developments, it is important that the mechanism to account for these ACS metering service cost variances can be administered efficiently and predictably. JEN therefore proposes that the ACS metering pass-through process should follow the equivalent procedural elements of NER 6.6.1 for the purpose of a DNSP submitting and the AER considering an ACS metering pass through for a positive or negative pass through event.

Appendix A
Operating expenditure step changes

A1. Inspection of metering installations

A1.1 Nature of the step change

This step-change relates to the NER obligation to inspect metering installations (including AMI meters), as per the NER chapter 7, AEMO metrology procedures and JEN's AEMO-approved Metering Asset Management Strategy (**MAMS**).

Our inspection obligations

JEN's AEMO-approved MAMS establishes our obligations for meter inspections and testing. Section 4.2.2.2 on Type 4-6 installations states:

> *All Type 4, 5 and 6 metering installations are to be inspected at the time of testing in accordance with NER Schedule 7.6, table S7.6.1.3. A qualified meter technician shall inspect all metering installations as per the inspection procedure at the time of meter testing. Furthermore, all meters remaining in service for more than 15 years will be 100% inspected within the 5 years following their 15-year anniversary of installation.*

These MAMS requirements reflect how JEN complies with the NER chapter 7.

JEN currently tests every CT-connected meter on a 5-yearly basis. For these meters, JEN does not have to provide a separate metering installation inspection program, because AEMO guidelines allow for the practice of inspecting meters “at the time of testing” when all meters are 100% tested at NER-defined time-based periods (time-based testing). However, 99.4% of JEN's Vic AMI meters are whole current (direct connected) meters. These meters are not tested using time-based testing. Instead, direct-connected meters are tested using a sample-based approach (for example, testing of a small sample of these meters), with the vast majority of these meters never having been physically visited/inspected by a technician since their original installation. AEMO guidelines make it clear that these meters should be subject to a standalone inspection program in order to meet the intent of relevant clauses of NER.

The NER (S7.6.1(c)) requires provision of inspections and testing in line with the prescribed minimum frequencies or an AEMO-approved metering asset management strategy. The NER do not set default minimums for whole current meters, which means JEN must rely on its AEMO-approved MAMS and its test plan, which has been registered with AEMO[40] for compliance.

In Oct 2019 AEMO published a Position Paper on Whole Current Metering Installation Testing & Inspections outlining the expectations for a typical metering inspection. Relevant AEMO guidance is:

> *“For inspection of metering installations, the intent of Schedule 7.6 for an inspection is:*
>
> - *a physical site visit to confirm compliance of the metering installation*
> - *a practice of inspecting meters when tested only applies if testing of meters is time based.“*
>
> *“Traditionally a typical inspection would result in a physical site visit to conduct an inspection of the metering installation…”*

Whilst acknowledging that modern advanced metering systems and VIC AMI systems provide functionality to deliver a degree of remote monitoring of smart meters, it clearly states that:

> *“AEMO does not consider an inspection practice based solely on remote monitoring will meet the intent of Schedule 7.6. (emphases added)*

40 JEN's metering test plan is in its MAMS.

Our inspections approach

As part of its asset management and market responsibilities JEN is required to carry out inspection of all its metering installations, to assure integrity of JEN metering installations and metering services in compliance with NER.

Hence, to comply with NER and assure integrity of JEN metering installations, JEN performs two types of inspections of its metering installations on a business as usual basis, they are:

- *Physical inspections* | Metering installations inspection program outlined in in our MAMS (discussed further below).
- *Remote monitoring* | In addition to the inspections at the time of testing and aged based plans, JEN also developing/enhancing additional systems and processes for remote monitoring of the installation and meter performance and conditions, leveraging the AMI capabilities.

This physical inspection program for our AMI meter fleet deployed between 2009 and 2013 is the trigger for this operating expenditure step change.

Because of the age of our meters (78% most of them were installed during 2009-2013), the volume of metering inspections we are required to conduct during the next regulatory period is unprecedented. But it is still necessary to assure integrity of our metering installations and address AEMO guidelines relating to physical site visits.[41] For this reason JEN has established coordinated plans to perform physical inspection program co-optimised with aged meter replacement of first generation AMI meters. The program must ensure that every whole-current meter on JEN is physically examined (via a site visit) within the five-year period following the 15-year anniversary of the meter installation and every 15 years thereafter. The aim of the metering installations inspections program is to monitor electricity meter installations integrity, safety, security and functionalities.

How we have minimised our inspections costs

Our AMI meter inspection and replacement business case[42] demonstrates how we have prudently planned to co-optimise this inspection obligation with a proactive replacement of failing meters. This approach minimises the combines cost of inspection (operating expenditure) and end of life replacements (capital expenditure) and minimises the installation costs of the end of life replacement relative to the default alternative of doing these in an uncoordinated way where they fail in the field and require ad hoc replacement within 10 days of the failure.

JEN has therefore worked to minimise its operating expenditure costs of meeting the physical inspection obligation of its MAMS by:

- co-optimising inspections with our end of life replacement program to lessen inspection numbers where a meter is replaced instead and the site visit labour costs are therefore capitalised
- adopting a geographically coordinated inspection program across our network area following the lessons learned from the equivalent coordinated smart meter deployment between 2009 and 2012
- investing in field mobility devices and software to improve the efficiency of our inspectors.

A1.2 Quantification of the step change

Our forecast step change is set out in Table A1-1.

Table A1-1: Meter inspection step change ($ June 2026, millions)

	FY27	FY28	FY29	FY30	FY31	Total
Field inspections (including testing and inspection program management)	3.82	3.66	5.07	5.07	3.93	**21.55**

41 AEMO, *Position Paper Whole Current Meter Testing and Inspection*, October 2019.

42 JEN, *Inspection of Metering Installation Business Case*. See RIN-4.6.1.

	FY27	FY28	FY29	FY30	FY31	Total
Software licences to support field mobility			0.03	0.03	0.03	**0.09**
Total	**3.82**	**3.66**	**5.10**	**5.10**	**3.96**	**21.65**

Source: *JEN - Att 10-03M ACS Metering opex and capex model - 20250131*.

Forecast method for inspections

JEN's AMI meter and communications assets population began operational life in 2009 when JEN began installing AMI meters as part of the state wide AMI rollout project, Based on this, the age profile of our AMI meters indicates that approximately 127,126 AMI meters are now due for physical inspection over the next regulatory period. This is calculated by multiplying the volumes of the meters by the labour rate after deducting the number of meter replacements from the number of the required inspections.

Metering Assets:

Meter installation inspection plan is based on the age of the metering installations. The plan is developed taking into considerations the historical site activities/events such as customer churns, meter and service installations, testing and maintenance works and the site condition information gathered during those activities.

The plan calls for all metering installations to be physically visited and technically inspected within five years following the 15-year anniversary of their original installation (unless the meter is scheduled to be replaced in that 5-year period) and every 15 years thereafter. This meter inspection plan is outlined in JEN's MAMS.

Communications Assets:

AMI communication assets inspections, maintenance, and replacement is determined by the age, condition and performance of each individual assets. JEN is using communication network performance management and modelling software provided by JEN's AMI communication supplier and third-party specialised software to determine the performance of our AMI communications assets. The performance review and assessment is done annually with aged based inspections plans additional review when required as a result of changes to the network topology and configurations.

Forecast method for metering and communications asset inspections testing and program management

We forecast 3 FTE which is the minimum headcount required to provide program management expertise to coordinate and deliver such an unprecedent physical inspection program. The labour rates for the 3 FTE are based on independent benchmark rates.[43] The total labour cost was calculated by multiplying the labour rates and the 46 week plan and assumed 37.5 hours per week.

The capitalised component of inspections testing and program management element is calculated by multiplying the total labour cost with the portion of meters requiring inspection lifecycle and meter failure replacement out of the total meters that are due for inspections.

Forecast method for enabling software

Enabling software costs is based on the contracted base and growth volume of end nodes (Meters and Communications devices) to be managed in additions to the required infrastructure, applications and software licence costs, estimated number of software updates and maintenance and testing requirements. All new proprietary and non-proprietary applications and software's cost estimated upon scaling of historical estimates, vendor price and JEN's competitive tender processes.

[43] See Attachment 11-05M.

A2. Meter disposal costs

A2.1 Nature of the step change

This step-change relates to the costs we will incur to dispose of our replaced meters in a compliant manner.

Our disposal obligations

Our obligations to prudently dispose of decommissioned AMI meters arising from:

- The Essential Services Commission's Electricity Distribution Code Of Practice (2023)
- The Environment Protection Act 2017/2021 (the Act) provisions for the Management of Priority Industrial Waste and General Environmental Duty.

Our disposal approach

When JEN performs end to end life cycle management of its AMI metering and communications assets, the removed meters and communications equipment from the network that are no longer suitable to be reused/recommissioned within the network are permanently decommissioned and disposed of in accordance to JEN asset management policies and procedures.

JEN complies with its obligations cited above by engaging an accredited disposal and recycling agent to undertake the disposal of all electricity metering and metering communications assets. In most instances, this involves returning the decommissioned assets to the manufacturer for disposal or materials recovery. This disposal practice is supported by monitoring, auditing and reporting processes to ensure traceability and full compliance is maintained and demonstrable to the relevant enforcing agency (i.e. the ESC or EPA).

How we have minimised our disposal costs

JEN has established meter and communications asset assessment and disposal processes to ensure the following:

- Asset life cycle extensions to avoid unnecessary and premature disposal of the asset
- Establish cost-optimised contractual agreement (Service Packaging) with the service providers

Decommissioned meter and communications assets are collected and disposed of by authorised, certified, and qualified entities (meter and communications equipment manufacturers, their agents, or subcontractors) with JEN oversight.

A2.2 Quantification of the step change

Our forecast step change is set out in Table A1-.

Table A1-2: Meter disposal step change ($ June 2026, millions)

	FY27	FY28	FY29	FY30	FY31	Total
Meter disposals	0.15	0.41	0.63	0.75	0.89	**2.84**

Source: *JEN - Att 10-03M ACS Metering opex and capex model - 20250131*.

Forecast method

JEN's forecasted meter disposal cost is calculated by multiplying the sum of meter abolishments and lifecycle replacement volumes with the disposal unit rate.[44] Unit rates are sourced from JEN's contract with its metering manufacturer.

[44] Cost of a fixed price per transportation pallet, with changes in volume not affecting the disposal price.

Appendix B
Our site visit unit rates

Jemena
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B1. Our site visit unit rates

This appendix explains the basis of the unit rates used in our operating and capital expenditure forecasts for ACS metering services. It is supported by the attached metering activities unit rate model.[45] (See attachment 11-03M) that provides the quantitative build-up of these unit rates.

B1.1 What forms of site visit are we forecasting?

This section explains the unique unit rates we have used when building our forecasts. The rates that are used in our forecasts are rates for:

- Proactive lifecycle meter replacement – meters that are replaced as part of our coordinated metering inspection program based on the assessed conditions of the metering installation.
- Failed meter replacement – meters that are replaced based on forecasted failure rates in the next regulatory period.
- Abolishments/service removed –removing a meter from the site
- Metering inspections - meters for our AMI meters that were installed over 15 years ago

B1.2 What is the scope of each form of site visit?

Each form of site visit involves a series of activities. Table B1-1 provides a detailed breakdown into the different sub-activities that are involved for each form of site visit.

Table B1–1: Breakdown of activities for each type of site visit

Form of site visit	Proactive lifecycle meter replacement	Faults and Failures	Abolishments / service removal	Metering inspections
Activities	Travel to site 10 minutes required Coordinated co-located multi-site visit (Two field workers)	Travel to site 25 minutes required Single-site back-to-base visit (Two field workers)	Travel to site 25 minutes required Single-site back-to-base visit (Two field workers)	Travel to site 10 minutes required Coordinated co-located multi-site visit (Two field workers)
	Field crew to complete JSA 10 minutes required (One field worker)	Field crew to complete JSA 10 minutes required (Two field workers)	Field crew to complete JSA 10 minutes required (Two field workers)	Field crew to complete JSA 10 minutes required (Two field workers)
	Setup traffic management 10 minutes required (One field worker)	Setup traffic management 10 minutes required (One field worker)	Setup traffic management 10 minutes required (One field worker)	Setup traffic management 10 minutes required (One field worker)
	Inspect and record service status and condition 5 minutes required (One field worker)	Inspect and record service status and condition 5 minutes required (One field worker)	Remove the service wire, and point of attachment and make it safe (if applicable) Time on task dependent on the meter type that's	Meter installation inspection Time and number of field workers on task dependent on the meter type that's being inspected

[45] See : *JEN - Att 10-01A Appendix B Metering unit rate model - 20250131*

Form of site visit	Proactive lifecycle meter replacement	Faults and Failures	Abolishments / service removal	Metering inspections
			being replaced (between 20 to 120 minutes) (One field worker)	(between 5 to 15 minutes) (One field worker for single phase meters and two field workers for 3 phase CT connect meters)
	Inspect and record the point of attachment status and condition 5 minutes required (One field worker)	Inspect and record the point of attachment status and condition 5 minutes required (One field worker)	Remove the meter board and make it safe Time on task dependent on the meter type that's being replaced (between 10 to 120 minutes) (One field worker)	Inspect and record the point of attachment status and condition 5 minutes required (One field worker)
	Replace the meter and perform post-installation safety and load test Time on task dependent on the meter type that's being replaced (between 30 to 120 minutes) (One field worker)	Replace the meter and perform post-installation safety and load test Time on task dependent on the meter type that's being replaced (between 20 to 60 minutes) (Two field workers)	The field crew completes paperwork, work activity records (WAR), records meter numbers, and removes traffic control devices. Time on task dependent on the meter type that's being removed (between 10 to 35 minutes) (Two field workers)	The field crew completes paperwork, WAR, records meter numbers, and removes traffic control devices. 5 minutes required (Two field workers)
	The field crew completes paperwork, WAR, records meter numbers, and removes traffic control devices. 10 minutes required (One field worker)	The field crew completes paperwork, WAR, records meter numbers, and removes traffic control devices. (Two field workers)		

B1.3 How have these been costed?

Installation labour unit rates

As discussed in section 5.4.1, the installation labour unit rates are based on independent benchmark rates. Our methodology follows Marsden Jacob's approach to setting the labour rates for ancillary network services as part of its report to the AER in June 2020[46]. The base salary used in the labour rate calculation is based on Hays 2024-25 published salary guide and the escalator used for wages are based on Bis Oxford Economics forecasts.

Number of workers required for metering activities

JEN has explored the option to utilise one crew member to undertake the metering activities. However, the works carried out for any meter replacement would involve live apparatus in the vicinity such as exposed live meter terminals and neutral link. In order to comply with Section 16.4 of the ETU Victorian Electricity Enterprise Agreement 2023,[47] two field crews are used to carry out the metering activities when calculating the metering unit rates.

Time on metering sub-activity tasks

To avoid duplication of labour activities, we have taken the maximum minutes of the two people used to carry out those sub-activities. From there, the total effort used to carry out the metering activities are calculated by multiplying the maximum total minutes by the two field workers and dividing the minutes by 60 to convert into the number of hours.

B1.4 What are our unit rates?

Table B1-2 summarises the unit rates for each of the metering activities used in our operating and capital expenditure forecasts for ACS metering services.

Table B1–2: Unit rates ($ June 2026, per activity conducted)[48]

Meter Type	Proactive lifecycle meter replacement	Faults and Failures	Abolishments/service removed	Meter visual inspections
AMI - Single Phase, single element	249.94	340.83	340.83	136.33
AMI - Single Phase, two elements with 31.5A load control	249.94	340.83	340.83	136.33
AMI - 3 Phase with no load control	295.39	363.56	431.72	136.33

[46] See *JEN - Att 10-03M ACS Metering opex and capex model - 20250131*.

[47] ETU, *Victorian Electricity Enterprise Agreement*, 2023.

[48] Rates escalated from Real June $2024.

Meter Type	Proactive lifecycle meter replacement	Faults and Failures	Abolishments/service removed	Meter visual inspections
AMI - Single Phase, single element, with 31.5A load control	249.94	340.83	340.83	136.33
AMI - 3 Phase with 31.5A and 2A load control	295.39	386.28	431.72	159.06
AMI - 3 Phase CT connect	477.17	431.72	522.61	159.06
AMI - 3 Phase CT & VT connect	658.95	522.61	795.28	159.06

Source: *JEN - Att 10-01A Appendix B Metering activities unit rate model - 20250131*