ALTERNATIVE CONTROL SERVICES

METERING

UE BUS 12.01 – PUBLIC
2026–31 REGULATORY PROPOSAL

Table of contents

1. Background

In 2009, the Victorian Government mandated the Victorian distributors to roll-out advanced metering infrastructure (AMI) meters in residential and small commercial premises consuming up to 160MWh per annum.

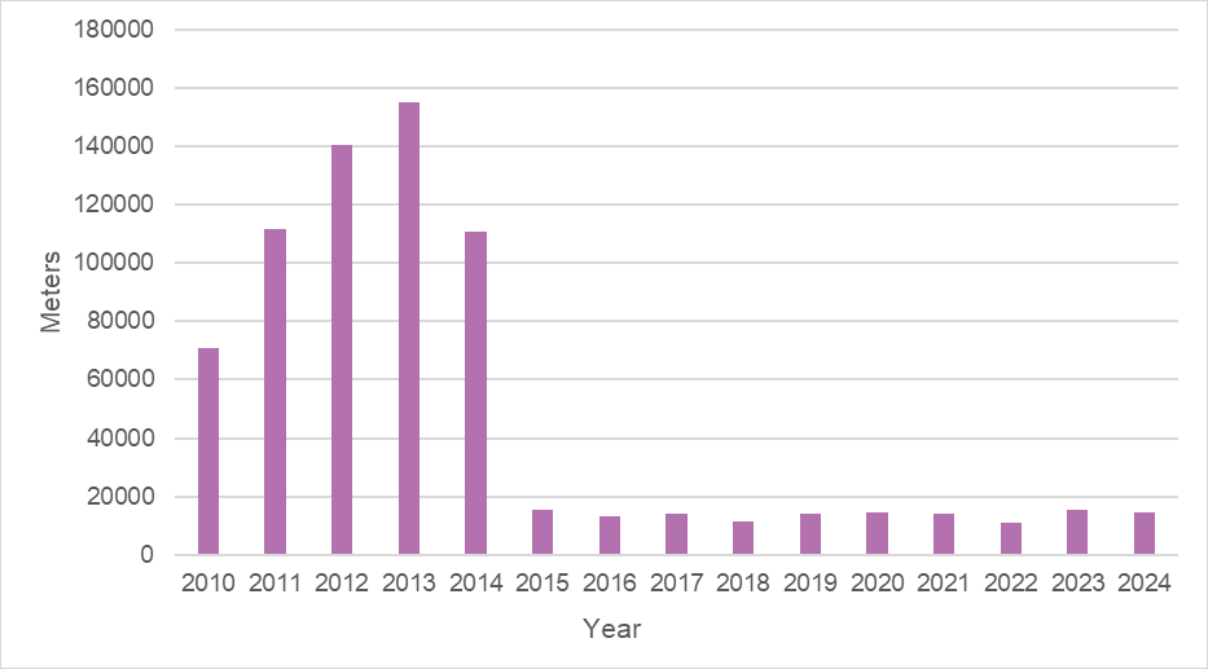
Our initial meter roll-out was completed between 2010–2014. To deliver on the Government's mandated rollout as efficiently and quickly as possible, a region-by-region approach was adopted, with the original 4-year AMI rollout dividing United Energy into 4 geographic regions as shown in Table 1. This delivered scale efficiency benefits, by allowing a 'street-by-street' rollout to occur.

TABLE 1 UNITED ENERGY'S ORIGINAL ROLLOUT

REGION	AREAS	METERS INSTALLED
Region 1	Blackburn, Doncaster, Elwood, Mount Waverley	173,791
Region 2	Bentley, Balwyn, Frankston, Clayton	245,161
Region 3	Glen iris, Mornington, Hastings, Sorrento	135,202
Region 4	Red hill, Kilsyth, Somers, Hallam	34,643
Total		**588,797**

Figure 1 shows the number of AMI meters that have been installed, by year, in United Energy's area, to 2024. Meters installed after 2014 have almost largely been for new connections with a smaller number of replacements and alterations.

FIGURE 1 TOTAL AMI METERS DEPLOYED BY YEAR



1.1 Benefits realised from existing AMI Meters

United Energy was required to install meters that comply with the Minimum AMI Functionality Specification (Victoria), 2008, which differed from the functionality that was later prescribed under the national Smart Meter Infrastructure Minimum Functionality Specification.

Our customers have benefitted from the lower costs and higher levels of service that have resulted from having had these meters installed. Whilst many of these benefits result from the functionality of the meter itself (for example, the ability to read the meter remotely as opposed to manually and the ability to remotely disconnect and reconnect a customer when a move in/move out situation occurs), several of the benefits stem from United Energy's proactive approach to intelligently leveraging the data that has become available from the meters to improve the level of service customers receives.

Table 2 provides a brief description of some of the benefits United Energy has been able to deliver by intelligently leveraging the data that has become available from the meters.

TABLE 2 BENEFITS UNITED ENERGY HAS REALISED FROM THE EXISTING AMI METERS

BENEFIT AREA	HOW UNITED ENERGY LEVERAGES METER DATA TO OBTAIN THAT BENEFIT?
Reliability of supply Quicker restoration of supply	Loss of supply allows resolution of issue and restoration of supply more quickly.
Customer notification and Life support customers Reduced exposure to loss of supply in emergencies	AMI data allows better rotation of load under emergency conditions Mapping of life-support customers' premises to LV transformers (currently in progress) allows more life-support customers to remain connected during emergency load shedding and to be provided with better communications regarding planned outages.
Customer safety Improved customer safety	AMI data identifies neutral faults at the customer premise, allowing us to identify unsafe conditions and undertake corrective actions, thereby preventing accidents from occurring.
Reliability of supply Better supply continuity	Information on voltage levels allows action to be taken that prevents load shedding under peak demand and excess PV export conditions.
Network planning and reduced spend Improved spatial demand forecasting	Information on loads (including PV export) at the local area level allows us to undertake more accurate assessment of the need for local network augmentation.
CER and demand response Digital network development	Use of AMI data in our Digital Network program enables a range of benefits including: better management of minimum demand conditions through load switching and reduction in PV export; enhanced ability to offer load control of customer appliances; the ability to monitor and optimise EV charging; the ability to provide more and better cost-reflective pricing incentives; better detection of electricity theft; avoiding blown fuses, which improves phase balancing and therefore better asset utilisation and reduced augmentation requirements; and better management of asset failures, reducing fire starts.
Improved quality of supply Better voltage management	AMI meter data is being used to monitor basic power quality levels at individual customer premises. Query and reporting tools have been developed that aggregate the data into meaningful sets of information and provide exception reporting to better manage the quality of supply to customers such as steady-state voltages, voltage sags and swells and phasing information.
Timely advice of outages	'Last gasp' information allows us to automatically advise customers of outages.

2. Meter failure rates

Our initial AMI roll-out population was completed in a concentrated four-year period. At the time of installation, their expected service life was around 15 years (consistent with expected life of the underlying componentry). To date, the actual engineering life of these meters remains uncertain, but they are the oldest and earliest forms of smart meters in service in Australia, and some of the oldest in the world.

That said, current failure data shows that current failure rates are relatively low, reflecting the fact that most meters are less than 15 years old, i.e., they have not yet reached their expected service life.

To the extent that there have been failures, these failures have tended to:

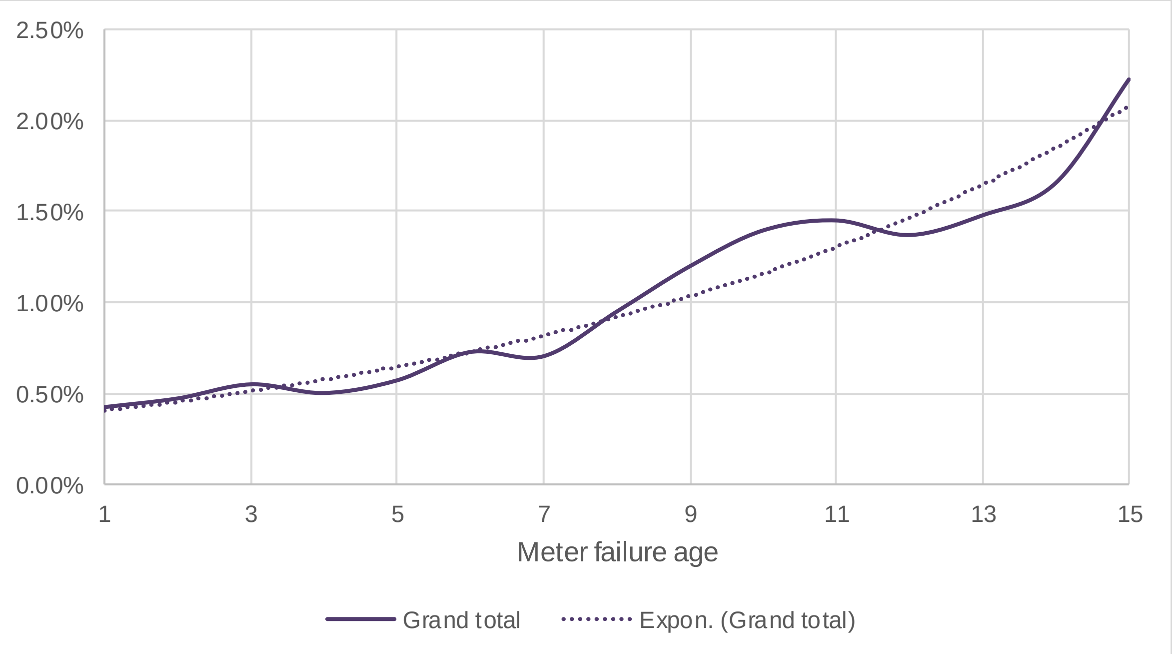
- be correlated with the age of the meter (see Figure 2); and
- reflect a failure of the componentry such as battery failures, data storage or communications failures (see Figure 3) as opposed to metrology errors (i.e. being inaccurate).

Meter failures broadly fit into 3 categories:

- **Category 1** - Immediate removal - This is where a key function has failed. This could be power supply or contactor failure where significant loss of functionality will occur. These will result in a meter no longer reading or a customer no longer getting hot water as the switching has failed on the meter.
- **Category 2** -Future removal - This is where the meter is likely to give significant issues in the near future. Examples are batteries or isolated memory failures. Memory failures are a good indicator that the memory is wearing out and corrupted readings and gradual communication signal degradation will become more common over time and should be removed in the near future.
- **Category 3** - Not serious enough to remove - This is where a function like the LCD screen has failed but can still be remotely read.

Figure 2 shows the failure rate, by failure age for our meters.

FIGURE 2 METER FAILURE, BY AGE



There is a significant correlation between the age of the meter and the likelihood of failure, especially increasing as the expected life of 15 years is approached.

FIGURE 3 FAILURE OF KEY COMPONENTS, BY AGE

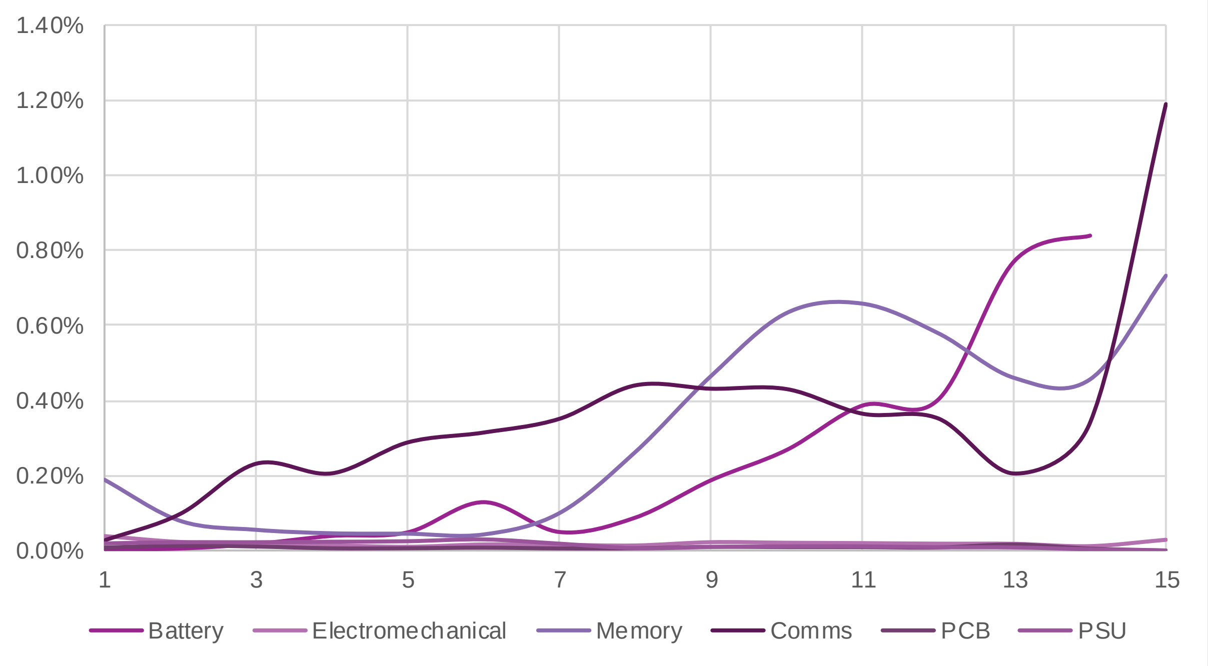


Figure 3 highlights that while some components, such as the electromechanical, power supply units (PSU) and circuit board (PCB) have experienced consistently negligible rates of failure over the course of the first 15 years of their operation, others are experiencing increasing rates of failure with time, most notably:

- **Batteries**: This is to be expected as batteries only last 10 to 15 years. Battery failure results in time-keeping issues and, in some cases, memory corruption.
- **Memory / Data storage**: This results in corrupted data and incorrect readings. Meter memory wears out over time and is generally related to the number of times the data in memory has been written to or erased. In this regard, it is worth noting that the meters were originally designed for 30-minute reads. However, United Energy is now required to record consumption and power quality every 5 minutes on a significant number of our meters. This is likely to accelerate memory failures.
- **Communications**: This results in the meter no longer being able to be read or controlled remotely.

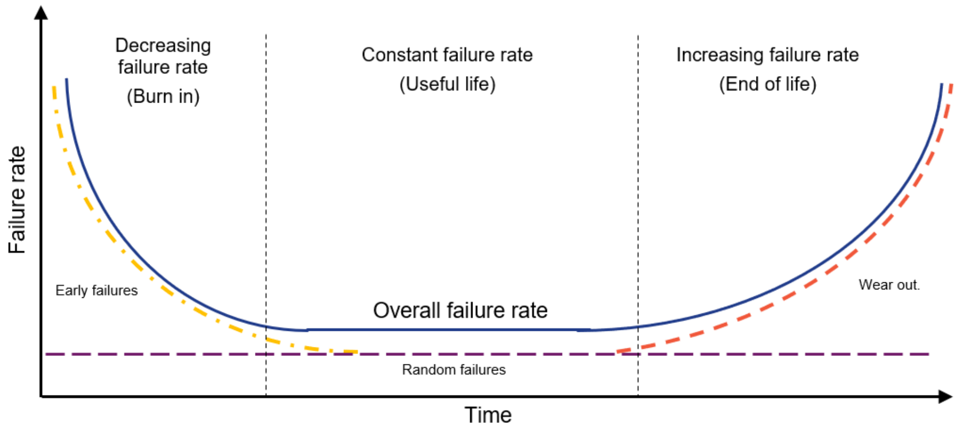
While meter failures can be corrected through refurbishment -- for example, if the battery fails, the meter can be removed, sent to the manufacturer and that battery replaced -- this only makes economic sense for younger meters. This is because most of the cost for fixing a meter failure is the cost of the labour involved in removing the meter and replacing the failed component. Based on these costs, United Energy has a policy of scrapping meters over 10 years old that experience any sort of failure.

The historic data supports the original thesis that it is the electronic components of the meter that will be more prone to failure than the metrology component. This aligns with the experience of many international jurisdictions, as is discussed in the following section.

2.1 How meter failure rates can be expected to change in the future

Meters, like many other engineering assets, can be described as experiencing a bathtub-shaped reliability profile. Failures tend to be relatively high in the earlier period of a meter type's deployment, with this primarily being driven by either manufacturing or installation defects. Failure rates then tend to plateau in the longer term, reflecting the fact that a new type of asset that successfully makes it through commissioning and the early phase of operation, tends to operate successfully in accordance with its design. Failure rates then tend to increase over time, as the individual assets approach the end of the asset type's design/engineering life. This is illustrated in Figure 4 below.

FIGURE 4 BATHTUB EFFECT



Source: See IJSRET_V7_issue2_209.pdf, pp 634-635 and The Bathtub Curve and Product Failure Behaviour (Part 1 of 2) for further information on the bathtub effect.

Drawing on information presented earlier, United Energy's current failure rates suggest that it is in the "useful life" period of the AMI Rollout Fleet. This is to be expected, based on the expected 15-year life of the underlying componentry. However, the data suggests that the oldest meters are approaching "wear out".

The difficulty is in determining the likely end of that "useful life" period before "wear out" begins, given that the vast majority of the meters we have deployed have not reached that period. That said, given that United Energy's metering fleet will be between 17–21 years of age by 2031 which exceeds the expected service life of the electrical components, it would be reasonable to expect that our metering population will begin to experience higher failure rates during the coming regulatory period. The historical data suggests this as well, given the:

- historical relationship between age and the failure of our meters
- the trend to higher failures in electrical components as they age.

It is also reflected in the experience other electricity businesses have had with smart metering. We engaged Blunomy to undertake a smart meter replacement benchmark study of international utilities. Blunomy identified international comparators for failure information and replacement drivers and strategies from the first wave of smart meters that have been rolled out internationally. All the comparators installed meters around the same time as United Energy, or earlier.

Blunomy's full report can be found in Appendix UE ATT 12.01 - Smart meters replacement benchmark study - Jan2025 - Public. We have distilled the key findings of that report below.

Amongst the smart meter owners interviewed with fleets that are approaching or have exceeded their design life, five out of eight have reported a noticeable increase in failure rates.

Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and Vattenfall, with meters installed between 2007-2010, 2008-2011 and 2003-2008 respectively, have all experienced increasing meter failure rates as the meters approached the end of their design life (15 years). PG&E and SCE both reported a recent increase in average failure rates, rising to approximately 2% for fleets aged 14-17 and 13-16 years, respectively. This is shown in Table 3 below. Previously, SCE's failure rates were below 0.5%. Vattenfall reported an increase in the average failure rate before its mass replacement program which started in 2021. During the plateau period of its initial fleet (between 5 to 10 years old), Vattenfall reported a failure rate of about 0.3%. As the meters went beyond 10 years of age and approached the end of their 15-year design life, failure rates increased by three to four times to approximately 1%-2%.

TABLE 3 REPORTED ANNUAL FAILURE RATE VS AVERAGE FLEET AGE FROM INTERVIEWEES

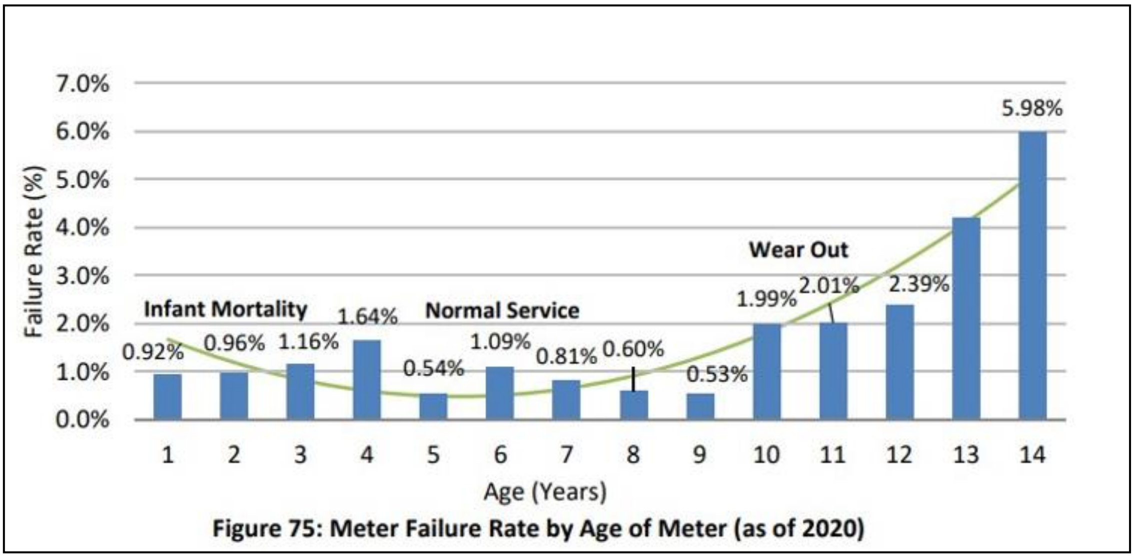
COMPANY	WHEN METERS WERE INSTALLED	AGE OF METERS IN 2020	AVERAGE ANNUAL FAILURE RATE DURING MOST OF USEFUL LIFE	AVERAGE ANNUAL FAILURE RATES NEAR END OF USEFUL LIFE
Vattenfall	2003 - 2008	15 - 18 years	Below 0.3%	Between 1% and 2%
PG&E	2007 - 2010	13 - 16 years	(Not available)	Approx 2%
SCE	2008 - 2011	14 - 17 years	Below 0.5%	Approx 2%

Source: Blunomy

Among the smart meter owners interviewed, Hydro One experienced the highest rate of failures. In 2020, the utility reported a failure rate of about 2% across its entire fleet, which has since risen to about 5% in 2024.

A closer analysis of Hydro One meter failure rates by age reveals a close correlation between increasing meter age and annual meter failure rates. As shown in the figure, which is taken from Hydro One's 2021 regulatory filing, meters between 5 and 10 years of age had annual failure rates that ranged from about 0.5% to 1%. By contrast, the annual failure rate for meters greater than 10 exceeded 2%. Notably, meters over 12 years of age showed consistently higher annual failure rates, reaching about 4% for meters aged 13 years and about 5% for those aged 14 years.

FIGURE 5 HYDRO ONE METER ANNUAL FAILURE RATE BY AGE AS OF 2020



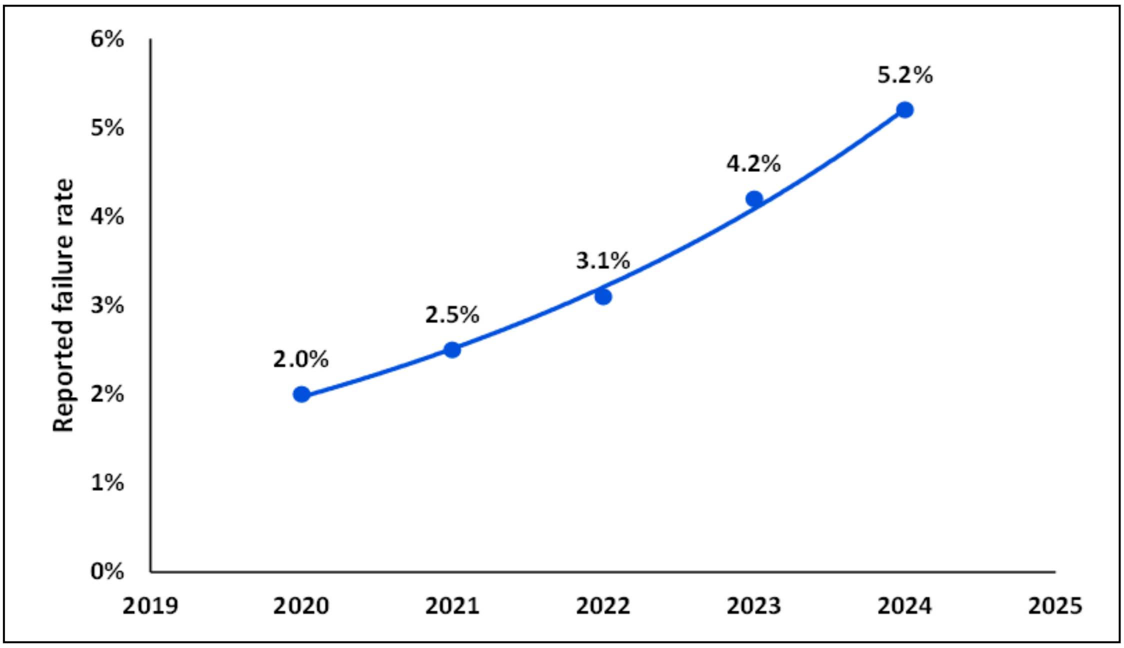
Source: Hydro One

Importantly, it should be noted that the shape of the failure rates shown in Figure 5 closely resembles the phases of the bathtub curve mentioned earlier, and can be divided into three distinct periods:

- an infant mortality period during the initial years (years 1-4) with a low and decreasing failure rate
- a plateau period during the middle years (years 5-9) with a low and constant failure rate (from about 0.5% to 1%); and
- a wear-out period during the latter years (year 10 onwards) with increasing failures as the meters reach the end of their design life.

Hydro One's fleet failure rate has now increased to ~ 5% in 2024 (YTD data). This is shown in Figure 6 below.

FIGURE 6 HYDRO ONE FLEET FAILURE RATE EVOLUTION (2020-2024)



Source: Blunomy

Amongst the smart meter owners interviewed, failures of smart meters were predominantly noted in functional (electronic) components, with minimal issues reported in the metrology components. SCE, BC Hydro, and Hydro One identified clock battery, capacitors and digital display failures as the most common causes of failure. Notably, SCE reported that over 50% of its meter failures were related to clock batteries. None of the eight overseas electricity businesses interviewed[1] reported any issues with the metrology components.

Amongst interviewees with smart meters using a radio frequency (RF) mesh network, six out of six reported the failure of the communication module was not the primary failure mode.

Two smart meter owners explicitly mentioned that the increase in failure rates across their meter fleets was a primary reason for them undertaking a mass replacement. Rising failure rates, coupled with uncertainty about the future trajectory of these failures, led them to adopt a 'calendar-based' approach for future replacements (i.e., replacement based on age).

The introduction of new features/functionality in smart meters was unanimously stated as a key consideration for future meter replacement, driven by national directives (in the case of the EU) or based on economic analyses undertaken by the businesses to support future network utilisation and defer network investments.

Among the five meter owners with replacement plans, four have scheduled mass replacement programs that will be completed within three to five years, driven by factors such as high failure rates, legislative deadlines or costs optimisation, in contrast to a more gradual replacement.

The meter OEMs that were interviewed[2] highlighted increasing failure rates across fleets, particularly as meters exceed their design life, as a key reason for smart meter replacement.

The key conclusions we have drawn from the international scan are that:

- failures of smart meters predominantly occur in their electronic components, which is consistent with United Energy's experience; and
- failure rates increase as the average age of the meter population approaches the end of their design life (typically 15 years).

2.2 Potential future failure rates

Using the above information, United Energy has conceptualised several credible 'future failure rate profiles' which have been used to inform its cost benefit analysis and associated sensitivity analyses (see section 5). Each of those profiles aligns with the increasing failures experienced internationally as meters approach and exceed their original design life of 15 years. The failure-rate profiles are designed to reflect the variability that has been experienced internationally (e.g., the slope of the increase in failure rates), and more generally, to demonstrate the impact failure rates have on the underlying economics of replacing meters under different replacement program options.

The three future failure scenarios have been developed.

Figure 7 shows our base case failure rate scenario.

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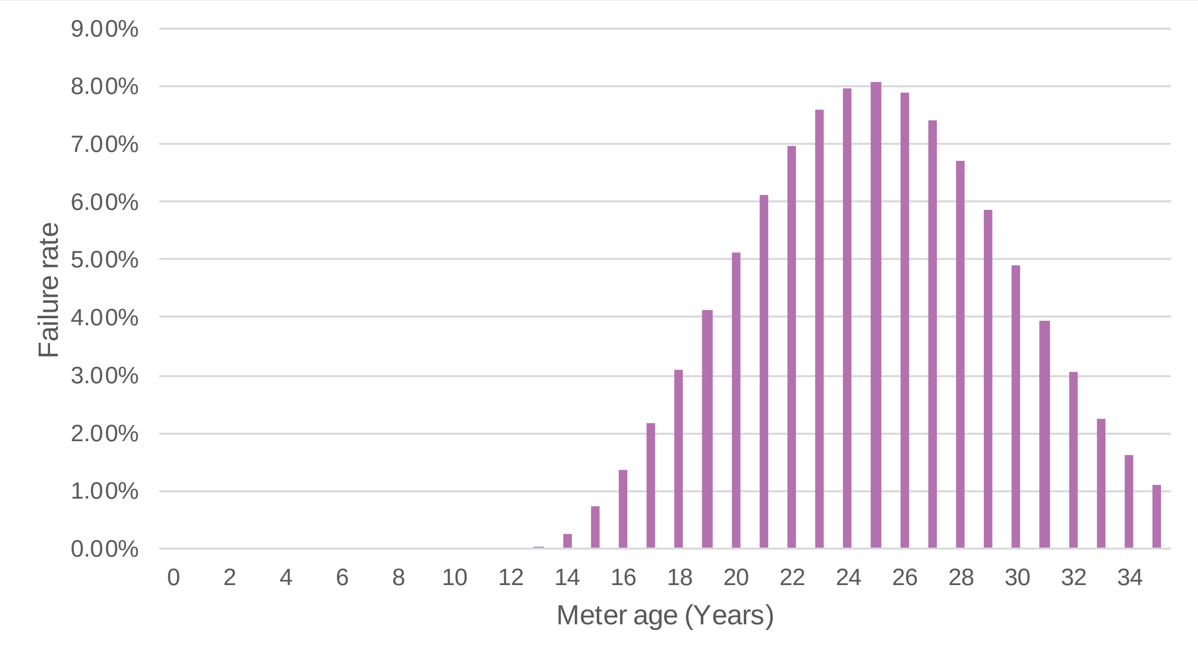
1 Those interviewed were: BC Hydro (British Columbia, Canada), Bluecurrent (New Zealand), Ellevio (Sweden), Enel (Italy), Hydro One (Ontario, Canada), Pacific Gas & Electric (PG&E, California, USA), Southern California Edison (SCE, California, USA) and Vattenfall (Sweden).

2 Those interviewed were EDMI and Landis & Gyr.

FIGURE 7 BASE CASE (EXPECTED ANNUAL FAILURE RATE)



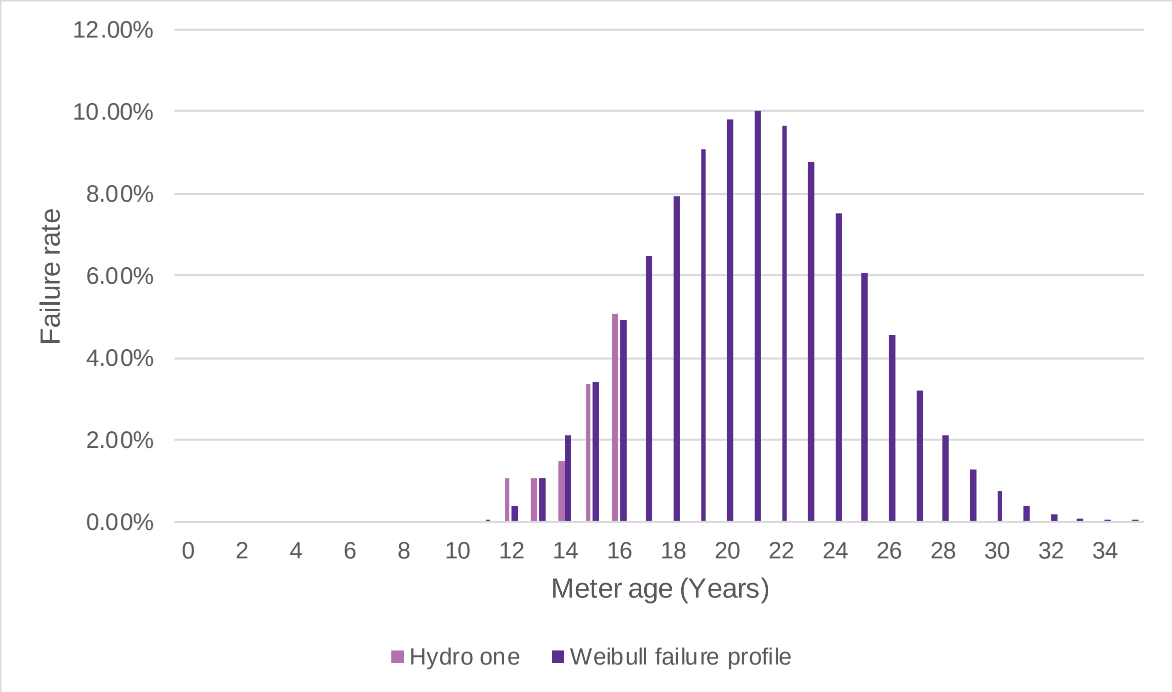
This failure profile has been created based on meter failure data and vendor information. More specifically the following inputs have been considered in developing this curve:

- **Historical data**: information on failure rates have been used as inputs into a Weibull analysis. Weibull Analysis is a methodology used to predict a product's life span. Weibull Analysis is a standard way of determining reliability characteristics and trends of a population. The data indicates that the meters are exiting their useful life at around 15 years and failure rates will start to increase from there.
- **Vendor consultation**: Meter vendors have indicated the meters are designed for a 20-year life span, however rates will increase from the 15-year mark due to components such as batteries having a shorter lifespan. Vendors have also indicated that meters in the majority are unlikely to last past 25 years.
- **International experiences**: Actual failure experiences for international companies have been used to align with real world curves.

We have adopted this profile as our base or expected case failure profile. In our opinion, this represents the expected (i.e., most likely) meter failure profile.

Figure 8 shows our faster failure profile scenario.

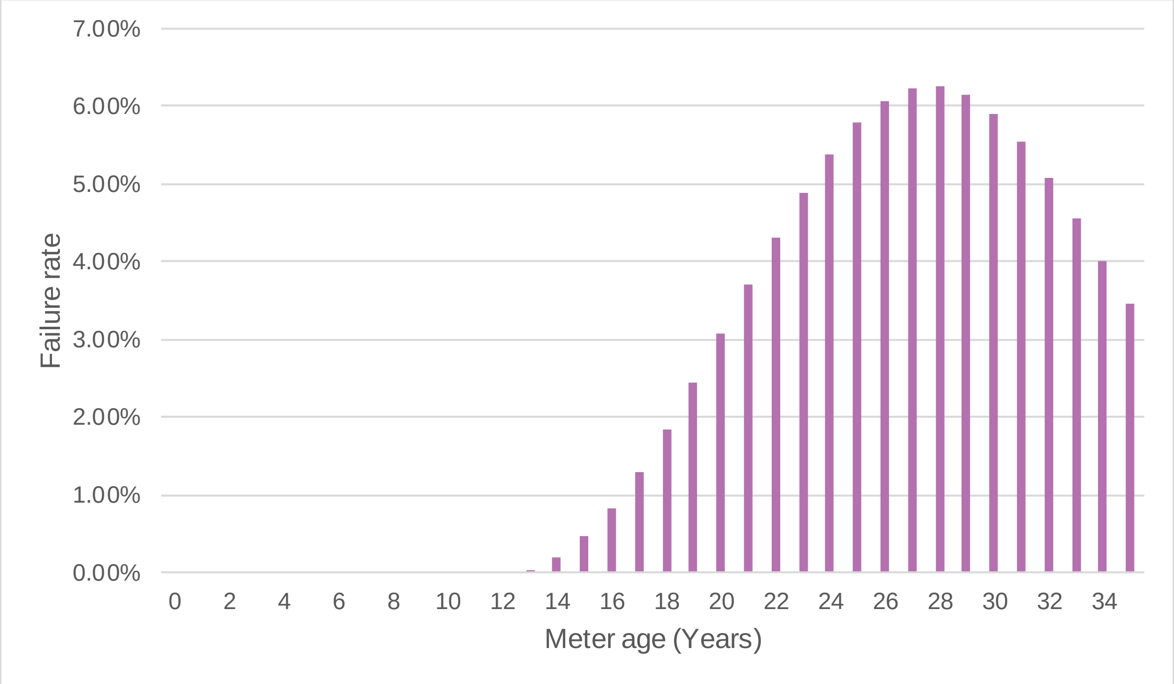
FIGURE 8 FASTER FAILURE PROFILE (BASED ON HYDRO ONE):



This faster failure profile is more aggressive than the expected profile, in that it assumes a larger increase in failures earlier on in the meter fleet's life. It is derived from the documented experience of Hydro One, which is Ontario's largest electricity transmission and distribution service provider and has been rolling out meters since 2006. In our opinion, given that it is real-world data, it represents a credible downside case. This failure curve is used to test the sensitivity of the results, if failure rates were higher and occurred earlier than what United Energy has experienced to date and that are forecast under the expected case, therefore requiring an earlier and more intensive replacement effort.

Figure 9 shows our slower failure profile scenario.

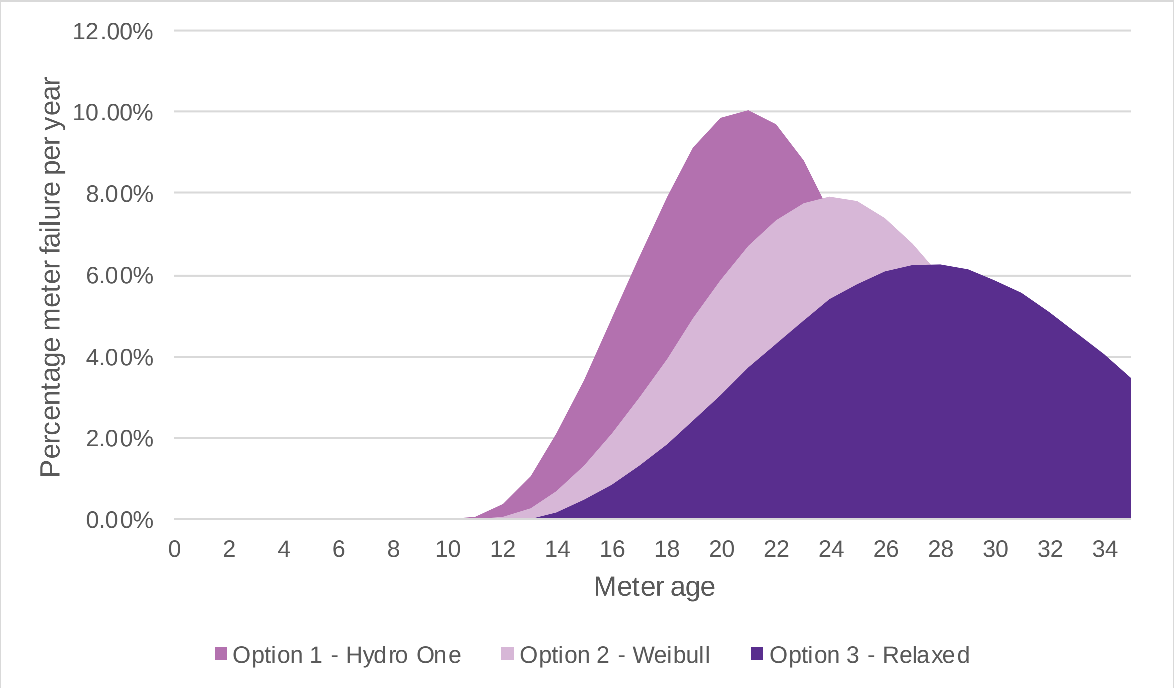
FIGURE 9 SENSITIVITY 2: SLOWER UPLIFT IN FAILURE RATES



This slower failure profile is characterised by a slower uplift in failure rates as meters age as compared to the expected case. It reflects a "longest life" scenario, where meters last significantly longer than their design life. We consider this unlikely to occur, however, as the slower failure profile results in some meters lasting more than 40 years, with a mid-point of 28 years.

Figure 10 below shows the three failure profiles on the same graph for easy comparison.

FIGURE 10 THREE FAILURE PROFILES



3. Responding to expected increasing failure rates

If we leave the AMI rollout fleet in service into the “wear out” period we will be forced into a “reactive replacement” program suffering from a lack of planning, and inefficient use of field resources, and significant disruption to customer billing and market settlements. Table 4 outlines the potential implications if increased failure rates eventuate.

TABLE 4 POTENTIAL IMPACTS OF INCREASED FAILURES

IMPACT	DESCRIPTION OF IMPACT
Increasing levels of reactive meter replacement	Increased OPEX / CAPEX, with a loss in economies of scale resulting from: • Travel time - Reactive meter failures are random in nature and therefore geographically spread, significantly increasing travel time. • On site time - Reactive replacement involves some level of fault finding, which increases on-site time. The amount of on-site triage time will depend on the failure rates and meter age.[3] A blanket rule to reactively remove meters without triage results in good / new meters being removed for no reason. • Higher labour charge - Specialist crews are required to carry out triage on meters. They have a higher hourly rate than an A grade electrician (which is the qualification needed to do replacement only). • Higher fault call outs - Approximately 10% of meter failures result in a fault call out. This is due to customers calling for heating and hot water issues. Also, faulty measurement leads to false detection of electricity network faults.

Compliance risks	As failures increase, the risk of non-compliance also rises. There are 3 compliance aspects that are at risk:
	• Minimum AMI Functionality Specification (Victoria), section 4.1 requires:
	  ◦ 99% of data collected within 4 hours of midnight
	  ◦ 99.9% of data collected within 24 hours of midnight.
	• NER Rules 7.8.10 requires that:
	  ◦ Repairs must be made to a malfunctioned meter within 10 days
	• AEMO - Service Level Procedure: Metering Data Provider Services, section 3.12.4. Delivery of settlement-ready data requires that:
	  ◦ 99% final reads be available by 5pm.

[3] Triage time consists of the time required to identify the cause of the fault and to fix it. However, when the failure rate of the meters is high and the meter is old, the meter will be replaced rather than triage being undertaken.

	All of these compliance aspects are significantly at risk if faults increase, >1% over a year. [4] Two main factors affect our ability to meet these compliance aspects in the face of rising failure rates: • Onboarding labour resources: it takes around 2 to 3 months to find and train additional resources. This is often due to the resources not being immediately available. Unlike a planned program the onboarding process is not as efficient and cannot be ramped up quickly. If failure rates increase rapidly then any spare capacity in the current crew will be exhausted quickly. • Meter supply: Currently meters have a long lead time, with orders being placed 9 months in advance. Any buffer stock would be quickly exhausted if failure rates increase, and we would need to wait around 9 months for additional stock.
Increased safety risk	With significant numbers of meters failing there is loss of visibility of neutral integrity and high voltage issues on the network.
Electricity network performance degradation	AMI meters are currently used for outage detection and voltage regulation. Loss of visibility results in poorer outcomes in these areas. Increased failure rates may result in an increase in the amount of time during which the customer does not have a functioning meter[5]. Where the customer uses meter data to influence consumption or export behaviour (for example where the customer is enrolled in a VPP or demand response arrangement) this can result in a financial loss to the customer and a reduction in allocative efficiency for the electricity system.

3.1 How we could potentially respond to increased failures

Broadly, there are two credible approaches that we consider could be adopted in response to increased meter failure:

- **Reactive** replacement approach, which involves simply replacing the meters as they fail. This represents a continuation of our existing approach, and is well-suited to situations where meter failure rates (as a percentage of the broader meter fleet) are low, and remain relatively consistent over time; or

- **Proactive** replacement approach, which involves developing a structured replacement program, targeting areas where meters are considered more likely to fail. This approach is well-suited to situations where meter failure rates are either high, or expected to increase significantly, and failures are generally correlated to a known/measurable variable such as age[6].

4 Based on United Energy research of the failure rate at which removal and replacement would not be able to be completed within the compliance period.

5 This is likely to be the case given that maintaining the current response time to meter failures would require United Energy to expand its meter replacement workforce to reflect the meter failure rate.

6 If there is a known explanatory variable driving failures (i.e., failures are not random), this allows a proactive replacement program to be created and structured in accordance with that variable, increasing the probability that a proactive replacement program targets meters that would have otherwise failed anyway in due course.

The following table summarises the potential options available, if failure rates are forecast to increase under any of the failure profiles discussed in section 2.2 above.

TABLE 5 OPTIONS FOR RESPONDING TO INCREASED FAILURES

OPTION NAME	HIGH-LEVEL DESCRIPTION OF OPTION
Reactive replacement (BaU)	Continue our existing approach of replacing meters when they fail
Option 1: Accelerated replacement	Proactive replacement of meters, removing meters based on age and meter type with known issues where such information is available.
Option 2: BaU to 2031, moving to proactive replacement from 2031 period onwards	Reactive replacement over the 2026 regulatory period followed by a proactive accelerated replacement program from 2031 onwards

Conceptually, each has some advantages and some disadvantages. These are summarised below.

3.1.1 Reactive approach

The advantage of adopting a reactive approach (i.e., in which meters are replaced when they fail) is that it reduces (essentially to zero) the risk that United Energy will replace a meter before the end of its useful life. This means that capital spend is delayed as we would be removing the meter only once it fails (i.e., "just in time").

The disadvantages of the reactive approach include:

- Reactive labour component is much higher due to longer travel times having to be incurred as a result of meter installers having to travel longer distances between the locations where replacements are needed.
- Increased risk of labour and materials shortages. If failure rates increase unexpectedly, and over a relatively short period, it will require a ramp up in labour and/or materials (or both) with only short lead times to obtain these resources. The risk is increased by the fact that:
    - There is likely to be significant competition for this type of labour, given that all the Victorian distribution businesses are likely to see similar increases in their failure rates as their meters age at the rate as United Energy's. This is heightened by the fact that this type of labour is in strong demand from government construction and interstate meter programs, driven by the AEMC's recent rule change requiring NEM-wide deployment of smart meters by 2030.[7]
    - Materials need to be ordered 9 months in advanced from the manufacturers due to long lead time components and components that are in high demand. Unexpected increases in failure rates will likely increase the risk of the supply of materials falling short of requirements for at least some period.

[7] https://www.aemc.gov.au/rule-changes/accelerating-smart-meter-deployment

- As failures increase, the risk of non-compliance also rises. United Energy has assessed that if meter failures increase above 1% per year, then the following compliance requirements are at risk:
  - 99% of data collected within 4 hours of midnight (Victoria)
  - 99.9% of data collected within 24 hours of midnight (Victoria)
  - repairs must be made to a malfunctioned meter within 10 days (NEM)
  - 99% final reads be available by 5pm (NEM).

3.1.2 Proactive

Under a proactive meter replacement approach the meters would be replaced based on their age (with geographic location as a proxy for age, given that the meters were originally installed on an area-by-area basis as shown in Table 1).

The key conceptual advantage of a proactive replacement is that it will:

- increase the efficiency of the installation process by materially reducing the amount of travel time required per meter replacement (due to the pragmatic nature of the rollout (i.e., house-by-house; street-by-street)
- to a lesser extent, decrease the amount of on-site time required per meter replacement (due to the fact that no triage will be undertaken).

Proactive replacement programs are also planned, as a result significantly reducing the risk of both material and labour shortages as they are secured ahead of time. Recent supply chain issues due to COVID and tight labour market have demonstrated the importance of not relying on a “just in time” approach.

The potential disadvantage of a proactive replacement program is that it increases the risk that United Energy will replace a meter before the end of its useful life. This risk increases to the extent that future failure rates turn out to be lower for longer than expected.

Another potential disadvantage is where there is no single variable that solely and perfectly drives meter failure. While age has been shown to be the best predictor of meter failure, it is not a perfect predictor and there will be a distribution of failures around the average failure rate in any year for a particular age cohort of meter. A proactive replacement program will significantly reduce the number of meters that fail and need to be replaced outside the proactive replacement schedule. This will result in there being a relatively low "residual failure volume" (i.e., meters that still need to be replaced reactively). However, there will still be some level of residual meter replacement requirement under any proactive replacement program.

3.2 Distributed intelligence - AMI 2.0

AMI technology -- like almost every other data technology -- is improving in the functionality it provides at the same time it experiences relatively modest increases or in some cases reductions in unit costs.

The most recently available AMI technology and associated software allows significantly more analysis and decision-making at the meter and transformer level than has been possible previously. This is of increasing value as distributed energy resources (DER) and customer energy resources (CER) are being deployed in increasing numbers. The enhanced visibility of and control capability over the low- and medium-voltage distribution networks -- generally referred to as distributed intelligence -- available from AMI 2.0 technology allows better and faster management of the grid and DER and CER assets, with benefits for the owners of these assets and all customers.

This technology is already being used and delivering benefits in distribution networks in North America and Japan. United Energy is monitoring developments in this technology and has conducted an RFI process to get detailed cost, functionality and performance information about it to ensure it can be incorporated appropriately in the company's accelerated AMI replacement program.

The availability of this new level of functionality has been an important secondary component of the decisions of several electricity businesses overseas to undertake a mass replacement of aging smart meters. Examples of the improved functionality that these businesses valued include real-time data, fault and outage detection, and edge computing capabilities.

AMI 2.0 meters are also wi-fi enabled which allows real time metering data through internet connectivity and easy integration with other systems. This will allow a greater range of metering services to be provided to customers compared to the zigbee protocol embedded in existing AMI meters used in Victoria.

United Energy will be performing their due diligence on these products to ensure we choose the most suitable product to cover the customer and business requirements for the next 20+ years.

4. Stakeholder consultation

Stakeholders' views on a reactive and proactive replacement of smart meters were canvassed as part of Test and Validate programs in September - October 2024. Customers were posed the following question:

> "Electricity networks install and maintain smart meters in homes and businesses. Many smart meters are approaching an age where failure may increase in the coming years. In the event a customer's meter fails, this could lead to billing inaccuracies and potentially higher replacement costs.
>
> Which of the following options do you prefer for the timing and approach of these meter upgrades?"
>
> 1. Start proactively replacing meters from 2026. This prevents the likelihood of failures in the coming years. This results in maintaining current meter charges of about $5 per month.
>
> 2. Delay proactive replacement until after 2031. This means there might be an increase in failures in the coming years. This option would result in meter charges of around $4 per month from 2026 to 2031 (a decrease of about $1 per from the current $5 per month), but potentially increasing from 2031.

Option 1 - to start proactively replacing meters from 2026 (referred to below as the Accelerated Replacement Program) -- was preferred by 70.2% and 68.5% respectively of United Energy's residential and business customers who participated in the consultation process.

The group discussions held as part of the consultation process provided additional insight into customers' views about the rollout. Participants noted that a proactive meter replacement program would have both immediate and long-term benefits. Specific feedback included the following:

- participants agreed on the importance and value of upgrading meters without interruptions
- a targeted rollout approach was seen as the best way to optimise the effectiveness of the rollout without compromising the benefits the meters provide
- a proactive rollout approach was considered reasonable as it would provide both immediate benefits, such as the continued reliability of meter performance, as well as long-term visibility benefits
- participants wanted clear and transparent communications on the purpose and benefits of the rollout
- customers note the importance of maintaining privacy throughout the rollout
- the enhanced data and monitoring capabilities that could be provided by the new generation of meters were seen as benefits the rollout could provide.

5. Economic assessment of replacement options

We have undertaken an economic cost-benefit analysis of three different replacement options:

- **Reactive**: meters are replaced as they fail.
- **Proactive**: meters would be replaced on a geographic basis starting in the upcoming regulatory period (i.e., in 2026).
- **Delayed Proactive**: meters would be replaced as they fail in the upcoming 2026–31 regulatory period and on a proactive geographic basis starting in 2031-36 regulatory period.

Further detail on these replacement options can be found in our confidential attached metering model.[8]

We have then determined the net present value of the costs of each replacement program option, with the option that has the lowest NPV of costs considered to be the solution that is in the long-term interests of consumers. We consider this approach to be consistent with the Rules, particularly the National Electricity Objective (NEO).

The analysis does has not quantified potential benefits which include:

- **Bring forward of new meter functionality**: The benefits of the replacement meter itself are assumed to be the same as those provided by the old meter, however, we expect that the new generation of meters will provide benefits.
- **Reduction in non-compliance risk**: Non-compliance risk will increase under all scenarios, however, the earlier proactive replacement the greater the benefit of reduced non-compliance risk relative to reactive replant.

This makes the results of the analysis that has been undertaken conservative

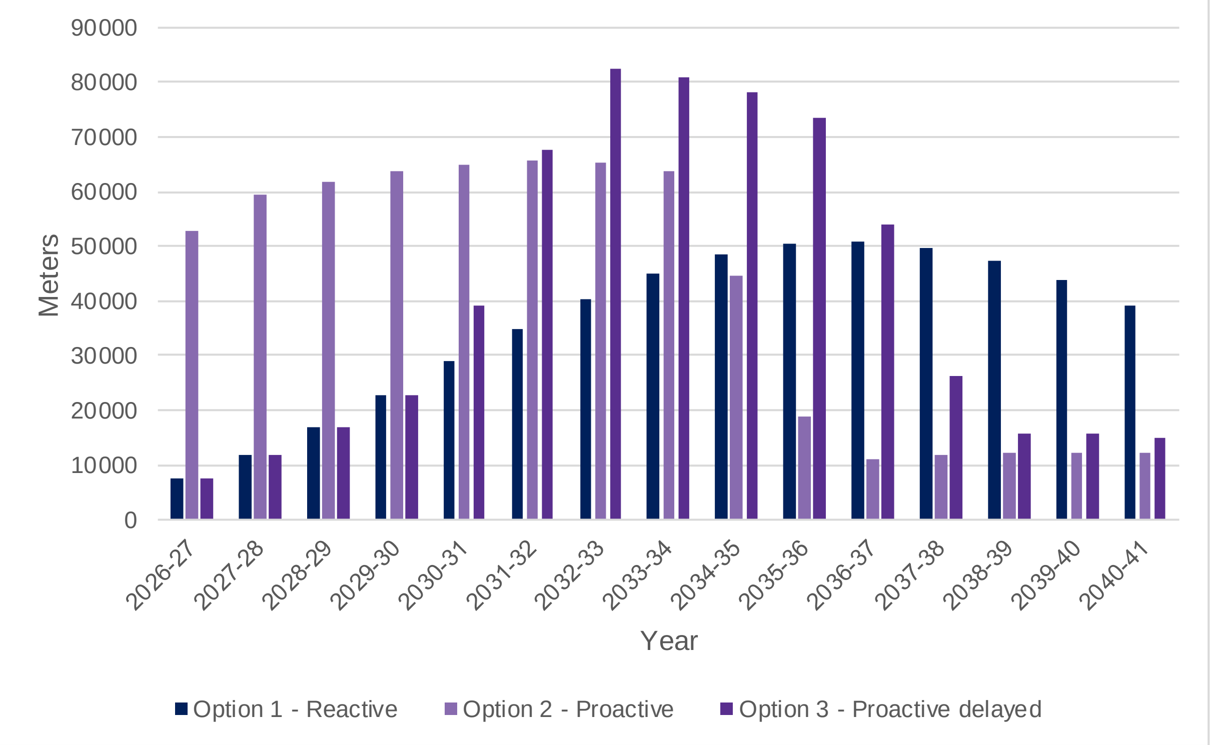
The NEO deliberately takes a longer-term view of meter replacement costs; it is not bounded by the artificial timeframe that results from the adoption of a series of 5-year regulatory control periods. By taking a longer-term view of costs and benefits, we are adopting an assessment framework that will produce results that are consistent with lower overall costs in the long term, which will translate to lower overall meter costs having to be recovered from customers in the long run.

5.1 Number, type and timing of meters to be replaced under each replacement program option

Figure 11 show the number of meters per annum United Energy would expect to install under each of the replacement programs modelled. All figures are based on the base case failure rate that was discussed earlier in section 2.1, noting that that failure rate is our "expected case".

[8] See UE MOD 12.04 - Metering business case - Jan2025 - Confidential

FIGURE 11 METER INSTALLATION NUMBERS PER ANNUM, BY REPLACEMENT PROGRAM OPTION



Note that in the figure above:

- Meters replaced are a combination of proactive replacement and residual failures and that is why meter replacements continue past 2039. In the proactive replacement we are only replacing the majority of the mass rollout meters. There will continue to be residual failures as the non-mass rollout meters get older.
- Proactive replacement is planned and therefore has a significantly higher chance of getting the level of resource (i.e., meter replacement labour) needed for it. It is also predominantly carried out by external resources that are not specifically metering technicians and only need to be grade A electricians, which significantly increases the available labour pool.

Figure 12 shows the number of meters that are replaced proactively versus reactively under each of the meter replacement program options. This demonstrates the relationship between proactive replacement and reactive replacement. It also shows that the delayed accelerated replacement option results in a much higher number of residual reactive replacements as compared to an accelerated replacement option that starts in 2026.

Note also that the number of meters expected to be replaced under the BaU reactive replacement approach is about 12% less than in either of proactive replacement program options. This is because some meters can be expected to remain operational for 20 or more years, so are not captured in the 15-year analysis timeframe.[9] By contrast, both proactive replacement program options would bring forward the replacement of all meters based on their age, so none of the original meters would remain in place beyond 2039.

[9] This also has implications of the results of the CBA assessment as discussed in section 15.2

FIGURE 12 METER INSTALLATION NUMBERS, BY REPLACEMENT PROGRAM OPTION

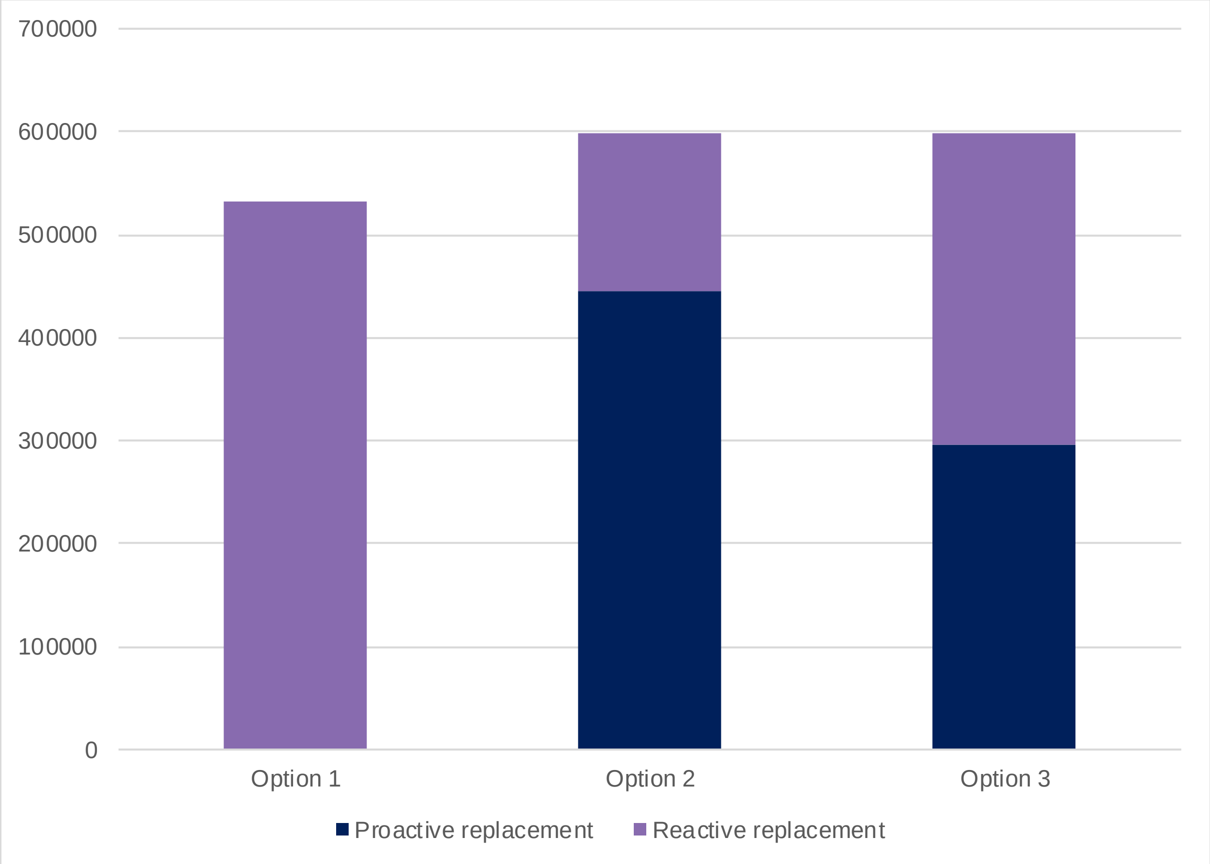


Figure 13 and Figure 14 demonstrate how the accelerated and proactive replacement programs are assumed to lower the residual probability of failure significantly:

- The blue area in each of the two following figures shows the annual failure volumes that would be expected to occur if no proactive program is undertaken. All of these replacements would be reactive.
- The orange area shows the number of meters that would be replaced monthly under the accelerated proactive replacement program option.
- The red shows the number of residual failures that would be expected to occur under the accelerated proactive replacement program option is undertaken. These would also need to be addressed reactively.

To be clear, the total number of meter replacements that would be required per month under the accelerated and proactive replacement programs would be the sum of proactive and residual replacement.

FIGURE 13 RESIDUAL FAILURES UNDER A PROACTIVE REPLACEMENT PROGRAM

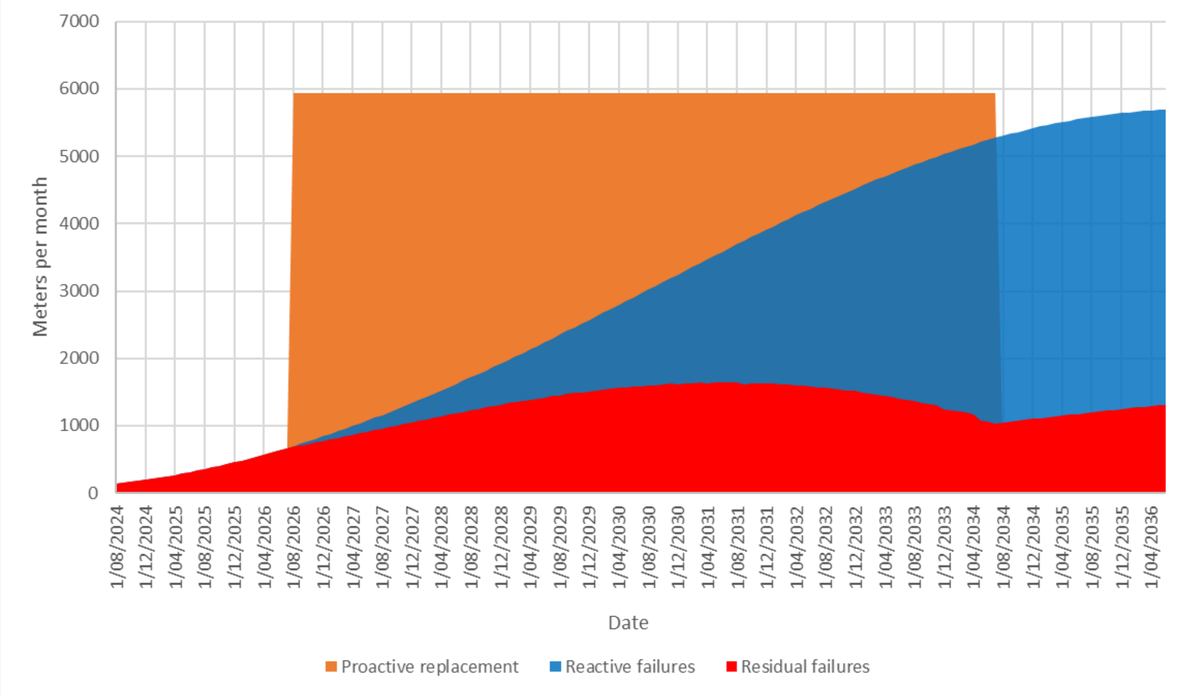
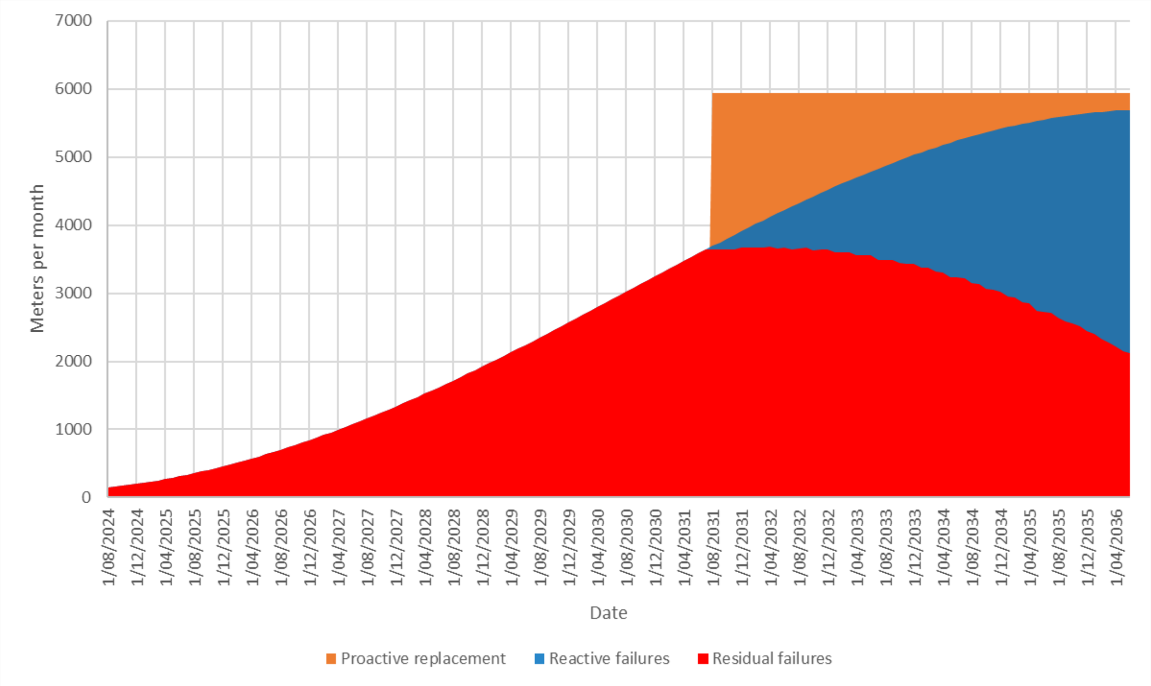


Figure 14 shows how a delayed proactive replacement program would affect the number of residual replacements that would be expected to occur under a delayed proactive replacement program. The nature of the replacements is the same as in Figure 13:

- The blue shows the resulting failure volumes if no proactive program is undertaken.
- The orange shows the number of proactive replacements.
- The red shows the residual failures that would be expected even though the delayed proactive replacement program had been undertaken.

FIGURE 14 RESIDUAL FAILURES UNDER A DELAYED PROACTIVE REPLACEMENT PROGRAM



Many more reactive replacements would be expected to be needed under the delayed proactive replacement program than if the accelerated program commenced in 2026.

5.2 Key assumptions underpinning the modelling of the meter replacement options

We have adopted several common assumptions, including:

- An evaluation period of 15 years (which is associated with the expected life of a smart meter)
- A real pre-tax WACC of 3.64%
- All prices are in AUD$2026
- Labour rates are escalated according to the negotiated ETU EBA.
- Material costs are escalated according to inflation calculations.

The following table summarises the key assumptions underpinning the modelling of the replacement program options.

TABLE 6 KEY ASSUMPTIONS UNDERPINNING THE MODELLING OF ALL OPTIONS ASSESSED

OPTION	SINGLE PHASE UNIT RATE
Capital Cost - Meter	$295.96/meter
Proactive replacement labour	$144.83/meter
Reactive failure (base rate)	$378.01/meter
Faults labour	$850.40/meter
Reactive failure / Faults labour (blended)*	$493.29/meter

*: Assumed 10% faults, 15% two person crew

Table 7 contains additional information concerning the costs that would be incurred under each of the three replacement program options. The analysis assumes that all replacement meters to be installed will be single phase meters. Single-phase meters represent approximately 75% of the meters that are expected to be replaced. While the analysis was based on the expected proportion of each type of meter that would be included in the rollout, for ease of presentation and improved readability here we have only shown the assumptions related to the single-phase meter type.

TABLE 7 BASIS FOR KEY ASSUMPTIONS

ASSUMPTION	BASIS FOR ASSUMPTION
Capital Cost - Meter	• Assumed current Landis and Gyr meter pricing (purchased in USD) • Exchange rate 1.61 AUD/USD • Store handling, storage and shipping 15% • Inflation from Jun $2024 to Jun $2026 - 7.17% over the 2 years
Proactive replacement labour	• Labour escalated according to ETU EBA (13.1%, Jun $2024 to Jun $2026) • 100% single person crews • Average travel time - 12 minutes • Minimal travel time as meters will be largely replaced based on a geographic basis as a proxy for age. The average takes into account the fact that there may be some distance between proactive replacements, for example in rural areas or where some meters of the original installation cohort have already been replaced, thereby imposing more travel time between replacement sites. • On job time - 48 minutes

	• Contact with customer is made. JSEA assessment carried out. Meter is not triaged, it is simply removed and replaced. Any antennas are re-connected. NST test carried out.[10]

Reactive failure labour	• Labour escalated according to ETU EBA (13.1%, Jun $2024 to Jun $2026)
	• 15% - 2-person crews as per EBA
	• Average travel time - 44 minutes
	  ◦ Travel time is longer due to distance between failed meters.
	• On job time - 69 minutes
	  ◦ Parking found, contact with customer is made. JSEA assessment carried out. Meter is triaged to determine the cause of failure.[11] Once the issue has been determined the meter will be removed and replaced. Any antennas are re-connected. NST test carried out.
	• Modelling assumes that as the failure rate goes up the travel time between meters will reduce. We have assumed a 25% reduction in travel time and that triage will no longer be undertaken when the failure rate gets higher, resulting in a 19% reduction in on-site time).

Faults labour	• Assumes that 10% of meter failures will result in faults (as per current data) • Labour escalated according to ETU EBA (13.1%, Jun $2024 to Jun $2026) • Faults crew are 2-person linesmen. • Time calculation assumes the same as reactive meter failure.

5.3 Results of economic modelling

The following table summarises the results of the modelling.

[10] Job Safety and Environmental Analysis (JSEA) and Neutral Supply Test (NST) are safety procedures which must be undertaken.

[11] Triage is undertaken because it is possible for meter readings to cease even when the meter has not failed. In many cases the loss of readings can be the result of communication issues, which can be readily addressed. Replacing the meter in such instances would be much more costly than the time required to identify and rectify the problem.

TABLE 8 RESULTS OF MODELLING ($M 2026)

REPLACEMENT OPTION	PV COSTS	NET BENEFIT
Reactive (replace on failure)	290.5	-
Proactive	274.7	15.8
Delayed Proactive	285.2	5.3

Figure 15 and Figure 16 show the impact of each item (different types of labour and material costs) in terms of their impact on the overall costs of the Proactive and the Delayed Proactive replacement options as compared to the Reactive Replacement case.

Figure 15 shows that:

- Materials costs (i.e., the capital cost of the meters installed), are higher in NPV terms under the Proactive approach as compared to the Reactive approach. This is entirely expected because more meters are replaced, and those replacements occur materially sooner, on average, under the Proactive approach as compared to the business-as-usual Reactive approach.
- Labour costs are much lower under the Proactive approach due to the substantial economies of scale that accrue from undertaking meter replacements on a programmatic, geographic basis.

On balance, the costs of the Proactive replacement option are $15.8m lower, in NPV terms, as compared to the costs of the Reactive replacement option.

FIGURE 15 DRIVERS OF COSTS AND BENEFITS - REACTIVE VS PROACTIVE REPLACEMENT

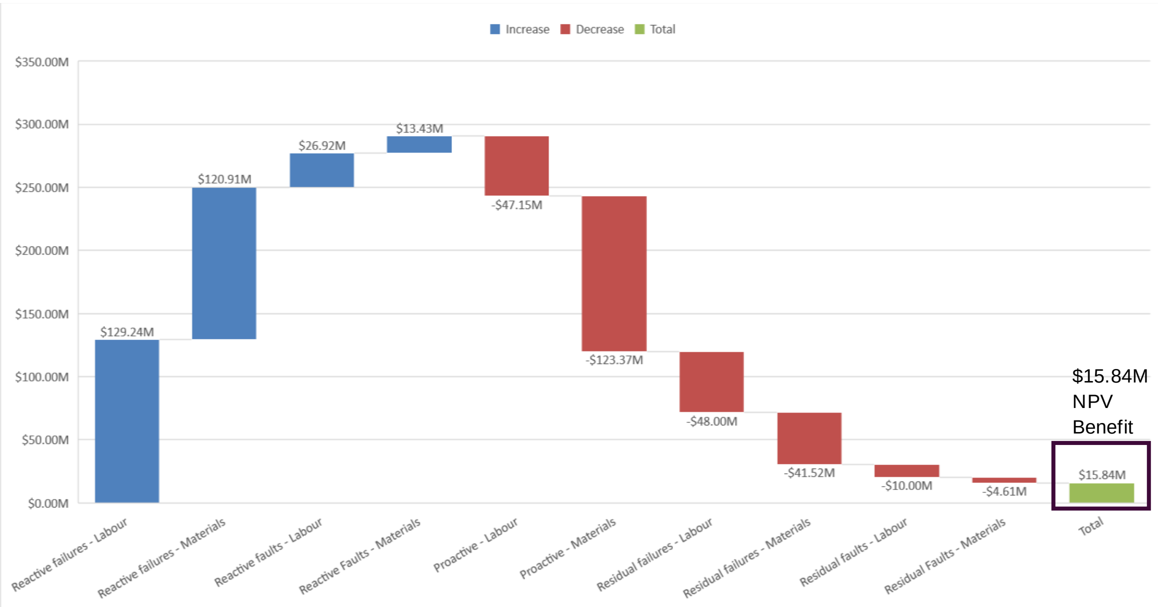
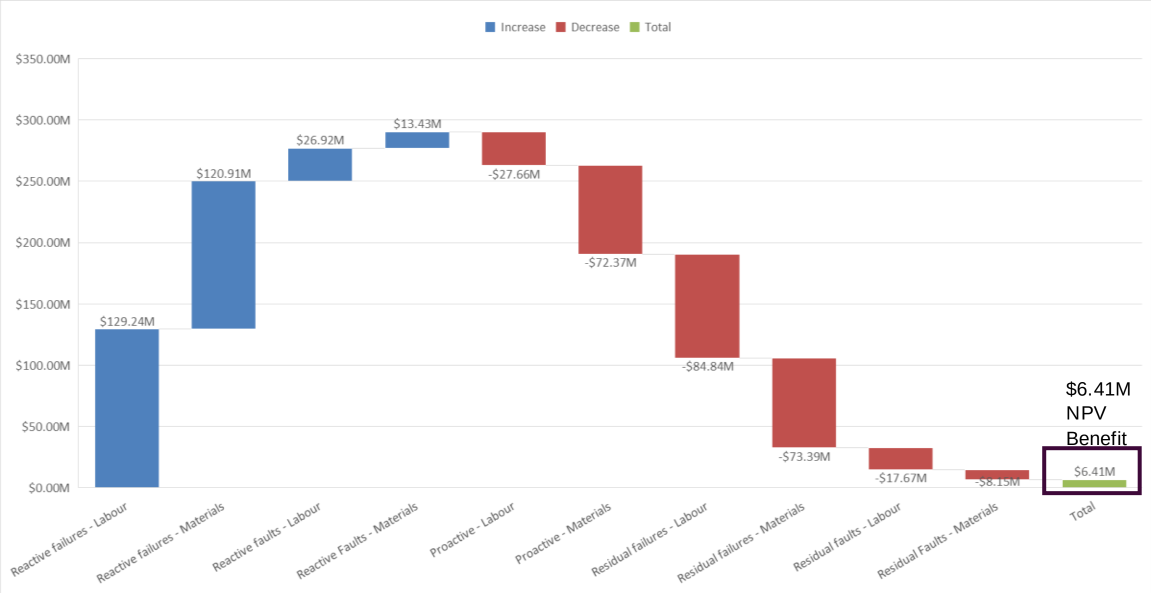


Figure 16 provides the same comparison between the costs of the Reactive and the Delayed Proactive replacement options.

It shows that the costs of Delayed Proactive approach are also lower than the costs of the Reactive approach, but not as low as those of the (non-delayed) Proactive approach.

FIGURE 16 DRIVERS OF COSTS AND BENEFITS - REACTIVE VS DELAYED PROACTIVE REPLACEMENT



5.4 Results of sensitivity analysis

The following table summarises the results of the sensitivity analysis. Each value result reflects the gross NPV of the costs of the parameter under each scenario, and it only reflects the changed parameter(s) discussed. Green cells indicate the replacement option with the lowest NPV cost (i.e., the preferred solution), whilst orange cells indicate the option with the highest NPV of costs.

TABLE 9 COST NPV SENSITIVITY ANALYSIS OF THE THREE REPLACEMENT PROGRAM OPTIONS

PARAMETER	REACTIVE REPLACEMENT	PROACTIVE REPLACEMENT	DELAYED PROACTIVE REPLACEMENT
Adopting the higher failure rate profile	358.0	317.1	347.2
Adopting the lower failure rate profile	193.4	243.2	236.6
+10% change in reactive replacement installation costs	303.7	281.3	296.6
-10% change in reactive replacement installation costs	272.9	270.5	276.9
+10% change in current tech capital costs	301.8	293.2	302.6
-10% change in current tech capital costs	274.9	258.5	270.9
6% WACC	236.7	243.2	241.3

The sensitivity results highlight that Proactive replacement is the preferred option under most conditions, except if the relaxed, slower underlying failure rate scenario were to eventuate or if a 6% WACC is used.

The effect of the above conditions is logical, as the former reduces the costs of the Reactive replacement approach (because underlying failures are lower) while not reducing the costs of the Proactive approach almost at all.

6. Meter testing

Under NER rule S7.6.2, a 100 per cent periodic physical meter inspection is mandated after a specified period, requiring visits to all sites to ensure compliance. This approach represents a significant operational challenge and financial burden.

United Energy has adopted an advanced "Digital Inspection" approach. This strategy utilises remote communication capabilities and power quality measurements embedded within the meters to conduct real-time remote monitoring and analysis across all sites.

The "Digital Inspection" method delivers superior outcomes compared to traditional physical inspections. It enables comprehensive, continuous monitoring, enhances operational efficiency, and reduces the need for costly, time-consuming physical site visits. This innovation has been accepted by AEMO as a viable alternative to the 100% physical inspection requirement, resulting in substantial cost savings for United Energy and, ultimately, lower bills for customers.

United Energy does not expect any material change in its inspection costs.

Meter testing

In addition to meter inspection, United Energy is also required under the NER to undertake sample meter testing at 3, 10 and 15 years after a meter is installed.

The costs we incurred in undertaking meter testing in the 2024 base year are abnormally low, and not representative of the costs we expect to incur over the next regulatory control period. This results from only being required to sample test a relatively small number of meters in 2024, due to the combination of the required meter testing timeframes and the age profile of the meter population. This same combination of factors will drive higher meter testing costs in the next regulatory control period, with an increasing number of meter families reaching the ages where testing is required.

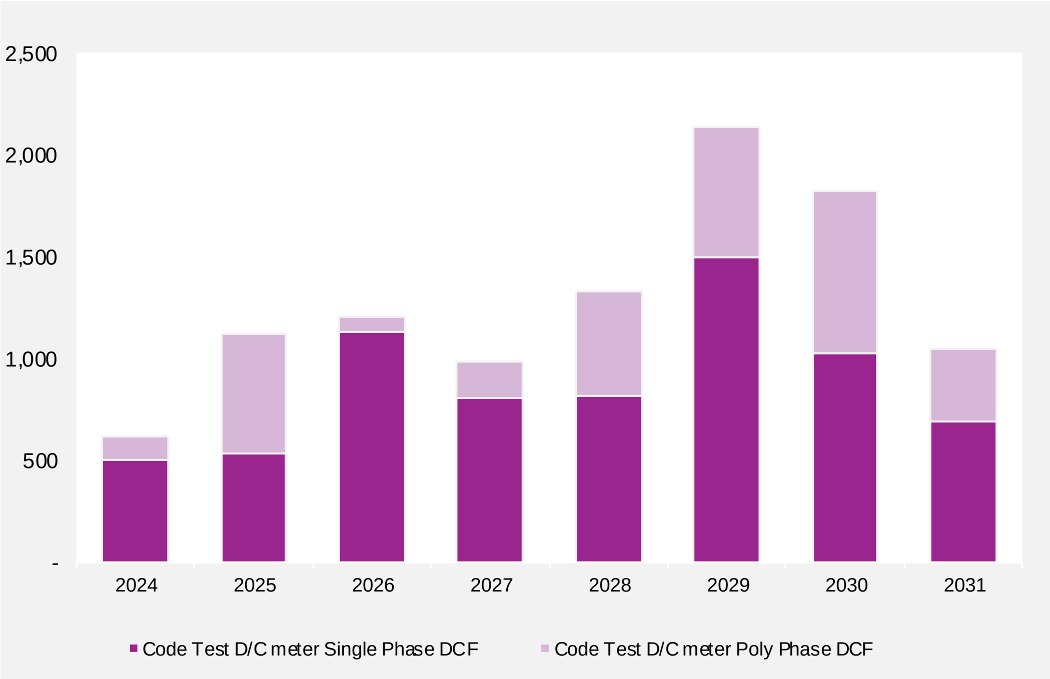
In addition to the above factors, United Energy is forecasting higher meter testing costs:

- in response to a family failure
- as a result of introducing new meter makes and models
- the impact of our proposed proactive replacement program.

6.1 Basis of opex step change

Figure 17 shows the step change in required meter testing volumes.

FIGURE 17 METER VOLUMES FOR TESTING



Our meter testing step change has been calculated in accordance with our attached confidential meter asset management strategy, which is approved by AEMO.[12] Our meter testing criteria are encrypted into our SAP based Meter Asset Management System (MAMS) which automatically generates testing requirements.

[12] See UE ATT 12.04 – Meter asset management strategy – Jan2025 – Confidential

Table 10 steps through the different components that make up our proposed meter testing step change, and how we estimated the impact of each of those components.

TABLE 10 BASIS FOR UNITED ENERGY'S STEP CHANGE ESTIMATE

DRIVER OF STEP CHANGE	DISCUSSION	APPROACH USED TO ESTIMATE STEP CHANGE AMOUNT
Family testing	United Energy's concentrated 4-year rollout of the first AMI Meters from 2010 to 2013 results in a significant peaking of testing volumes under the Rules[13]: • Between 2013 to 2016 - driven by the 3-year testing timeframe • From 2020 to 2023 - driven by the 10-year testing timeframe • From 2025 to 2028 - driven by the re-testing of those AMI Rollout Families after 15 years. The counterpoint to this is that the original 4-year rollout also resulted in a trough in testing volumes, due to the much smaller volumes of meters installed in the years from 2014 onwards; very little 3-year testing was required from 2017 to 2019, and very little 10-year testing was required in 2014. 2024 (base year for the 2026–31 opex) is a “trough Year” between the end of the 10 Year testing in 2023 of the 2013 AMI Rollout Meters, and the 15 Year testing in 2025 of the 2010 AMI Rollout Meters. This trough results in a step change in opex required for meter testing in the upcoming regulatory period.	Estimation of the step change amount requires calculation of the Unit Cost of testing and the number of tests that will need to be conducted. • The Unit Costs are based on existing labour durations for existing testing programs and escalated hourly rates based on economic forecast. • The testing volumes are based on the existing meter Make/Model/Year family volumes from 2009 to 2023 and applying the AS1284 Part 13 “Attributes” sample testing volumes on 3-year initial, 10-year and subsequent 5-year routine testing cycles (i.e. years 15 and 20).

[13] For example, Rule 7.6 in conjunction with the approved meter asset management strategy.

Impact of New Meter Makes and Models	The business will need to introduce new meter models due to obsolescence by current vendor’s legacy models and we may introduce a third manufacturer in addition to, or replace an existing manufacturer, to access the features that are being made available in new meter technology (see section 3.2 for further detail). That would then trigger the need for 3-year Initial Testing to be undertaken for up to 6 Models of each new Make of meter that are introduced in the 2026-2031 period for each year in which those meters were produced. The sample sizes that would be required would be dependent on the Make / Model / Year Family population, and the requirements described for Attributes Testing under AS1284 Part 13.	Estimation of the impact of new meter makes and models requires calculation of the Unit Cost of testing and the number of tests that will need to be conducted due to the introduction of new meter makes and models. • The Unit Costs are based on existing labour durations for existing testing programs and escalated hourly rates based on the economic forecast. • The testing volumes are based on the existing meter Make/Model/Year family volumes from 2009 to 2023 and applying the AS1284 Part 13 “Attributes” sample testing volumes on 3-year initial, and 10 -year and subsequent 5-year routine testing cycles (i.e., years 15 and 20). • Since 2021 and the impact of Covid on meter manufacturer supply chains, the business has been re-introducing dual supplier arrangements. This results, under AS1284 Part 13 “Attributes” sample testing volumes on 3-year initial tests of 2 Makes / x 5 Models per year (10 Families). • If a third manufacturer were to be introduced it would require the 3-year initial testing to being based on 3 Makes / x 5 Models per year (15 Families), meaning that 3-year testing would need to be conducted on 5 new models.

Impact of Proactive Meter Replacements	The significant rollout volumes will trigger significant initial sample testing of each Make / Model / Year. To this end, we expect to maintain our existing requirement to have at least two Makes or Suppliers to avoid interruptions to production / supply as had occurred during the Covid period. Due to the very high volumes, and to identify any design or manufacturing problems as soon as possible and under the warranty period, the business proposes to revise its Meter Asset Management Strategy to undertake the Initial Tests at Year 2, rather than Year 3 after installation, as is allowed for under AS1284 Part 13.	Estimation of the impact of undertaking the Initial Test of new meter makes and models in Year 2 instead of Year 3 after installation requires an estimate of the Unit Cost of testing, the number of meters that will need to be tested in Year 2 rather than Year 3 after installation and the economic costs of conducting those tests earlier than they otherwise would have. • The Unit Costs are based on existing labour durations for existing testing programs and escalated hourly rates based on economic forecast. • The existing testing volumes are based on the existing meter Make/Model/Year family volumes from 2009 to 2023 and application of the AS1284 Part 13 “Attributes” sample testing volumes on 3 year initial, and 10 Year and subsequent 5-year routine testing cycles (i.e., years 15 and 20). • Since 2021 and the impact of Covid on meter manufacturer supply chains the business has been re-introducing dual supplier arrangements. Under AS1284 Part 13 “Attributes” this results in sample testing volumes for 3-year initial tests of 2 Makes / x 5 Models per year (i.e., 10 Families). • If a Proactive Replacement program is commenced, the new makes and models would likely consist of two manufacturers and the 2-year initial testing would be based on 2 Makes / x 5 Models per year (10 Families) but the installation volumes of each Make/Model would be significant and result in significant testing volumes. The Australian Standards allow for testing to be undertaken in either year 2 or 3. Due to the high volume of installations of new make models that would occur under a proactive replacement, the businesses would move to a 2-year initial testing period to capture problems earlier than a testing in year 3 would provide.

7. Impact of electrification

We forecast that the Victorian Government's gas-related policies, including its gas substitution plan, will affect the mix of meter configurations used in new connections. As the remaining vacant land in existing urban residential developments (URD) estates that have rights to connect to the gas network is exhausted, there will be a shift to all-electric homes which will affect the supply and metering configurations.

On average, this will lead to a reduction in single phase non-contacting meters and an increase in either single phase, two element meters, or three phase meters. The change is expected to be both significant and permanent.

We also forecast that more of our existing customers will choose to retrofit electric space heating and electric water heating into their homes (and possibly induction electric cooking), leading to an increase in the volume of supply upgrades (Adds/Alts) which will also affect the mix of meter configurations relative to the historical mix that is reflected in our base year costs.

We've also seen more new houses proactively prepare for an increase in EV uptake and the existing plug-in-hybrid boom. This results in more houses connecting directly as a 3-phase connection. We also expect to see bigger solar connections coming online as the energy density of solar panels improve and the costs of batteries come down.

7.1 Basis of our proposed change in meter mix

The following table steps through the different components that make up our proposed electrification-driven change in meter mix, and how we estimated the impact of each of those components.

It should be noted that under the proposed Proactive replacement program, meters will be replaced with the same type of meter. The change in meter mix due to electrification is reflected in our forecast of new connections and meter upgrades.[14]

[14] A step change in installation costs associated with these meters is not claimed as it is fixed-fee alternative control service.

TABLE 11 BASIS FOR CHANGE IN METER MIX

DRIVER OF CHANGE	DISCUSSION	APPROACH USED TO ESTIMATE COST
New Connections	Currently, most new developments allow homes to connect to the gas network, with most customers taking up that opportunity. The Victorian Government now requires all new developments requiring a planning permit to be all-electric from 1 January 2024. The Victorian Government Gas Substitution Road Map – Update 2024 – figure 2, page 19, shows All-Electric Residential Permits per month increasing from 100 per month in 2024 to 300 per month by June 2024. While this does not change the number of meters that United Energy will be called on to install in new residential construction, it is expected to change the mix of meter types to be installed, with fewer single-phase meters (which to date have accounted for the largest proportion of meters) to other, more expensive meter types. This will result in higher meter capital costs than would have been evidenced in 2023 as the base year.	Estimation of the impact of the impact of the Victorian government's policy requiring new homes that require a planning permit to be all-electric requires estimating how this policy will affect the nature of the end-use equipment in these homes and the flow-on effect that will have on the overall mix of meter types that United Energy needs to install. • The existing meter type volumes are based on the historical trends of New Connections which saw a significant use of Single Phase Single Element Meters on Residential Customers who were using Gas for Space Heating and Hot Water. • The Victorian Government's Gas Electrification policy will see a significant fall in New Connections of Residential "Gas" customers and hence it is expected a greater demand for Electric Hot Water Load Control Metering and 3 Phase connections to support All Electric Homes. • All Electric Homes are expected to have, at a minimum, (a) Reverse Cycle Air Conditioning for Space Heating and Cooling (ducted three phase or multiple single phase units), and (b) Single Phase controlled load Electric Storage Hot Water • Some premises will also have (a) one or more induction cook tops, and either electric vehicle trickle charging or 3-phase fast charging. • This will result in a reduction in Single Phase Single Element "non-contacting" meters and a corresponding increase in Single Phase Two Element Meters (Load Control) and Three Phase Meters even though the total volume of New Connections is expected to remain the same (subject to the overall level of economic activity).

Meter upgrades	The Victorian government is providing significant subsidies to existing customers to replace Gas Hot Water units and Gas Space Heating.[15] These subsidies -- along with gas price increases, and the possibility of supply shortages -- are likely to increase the change-out of gas fired end-use equipment in favour of electric equipment. The nature and size of these end-use devices is expected to change the number of Add/Alt meter changes as well as the proportion of meter types used in these installations as compared to previous experience	Estimation of the impact of the government subsidies being offered to customers to replace gas water heating and gas space heating equipment requires estimating how its incremental impact on the number of Adds/Alts that will occur and the mix of meter types that will be required in those installations. • The availability of the subsidies along with gas supply constraints and consequent price increases will result in a significant increase in the total aggregate number of Adds/Alts. • The existing meter type volumes are based on the historical trends of Adds/Alts whereby meter replacements are largely driven by customer requested changes in Supply Configurations (the most common being from single phase to three phase. • The Victorian Government's Gas Electrification policy will see a greater demand for Electric Hot Water Load Control Metering and 3 Phase connections to support homes that are converting from Gas to All Electric. The projected "gas shortage" and resulting price increase will accelerate that further. • Adds/Alts are expected to have, at a minimum: (a) Reverse Cycle Air Conditioning for Space Heating and Cooling (ducted three phase or multiple single phase units), and (b) Single Phase controlled load Electric Storage Hot Water. This will result in an increase in Single Phase Two Element Meters (Load Control) and Three Phase Meters.

[15] The Victorian Government is also considering mandating that gas hot water units and gas space heating equipment in residential and small business facilities be replaced with electric equipment. The impact of the introduction of this sort of policy has not been assessed in this step change proposal.

8. Revenue and control mechanisms

8.1 Form of control mechanism

The AER decided in its final 2026–31 Framework & Approach paper for the Victorian distributors (F&A paper) that metering services are to continue to be regulated via a revenue cap form of control as an alternative control service.

8.2 Proposed control mechanisms

The AER decided in its F&A paper that the control mechanism would remain the same as for the current regulatory control period.

Appendix A replicates the control mechanisms in the AER F&A paper.

8.3 Proposed annual revenue requirements

Table 12 shows our proposed annual revenue requirements and revenue X factors for standard control services calculated applying the building block approach required by the National Electricity Rules (NER) using the AER's standard post-tax revenue model. Our metering PTRM is attached.[16]

TABLE 12 REVENUE REQUIREMENT ($M NOMINAL)

BUILDING BLOCK	2026/27	2027/28	2028/29	2029/30	2030/31
Return on assets	6	8	10	13	15
Regulatory depreciation	12	16	19	23	27
Operating expenditure	8	8	9	10	10
Corporate income tax	1	-	0	1	0
Unsmoothed revenue requirement	26	32	38	46	53
Smoothed revenue requirement	35	37	38	40	42
Forecast CPI (%)	2.75%	2.75%	2.75%	2.75%	2.75%
Revenue X factor (%)	12.39%	-2.00%	-2.00%	-2.00%	-2.00%

We have used the same forecast inflation, rate of return, value of imputation credits and debt raising rate as the values used for standard control services.

[16] See UE MOD 12.01 - Metering PTRM - Jan2025 - Public

8.4 Prices and price path

Table 13 shows the average resulting real prices calculated using our forecast annual smoothed revenue requirement and forecast NMI growth.

TABLE 13 FORECAST PRICES ($M 2026)

	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Single phase single element	52	45	45	45	45	46
Single phase two element	52	45	45	45	45	46
Three phase direct connected	58	50	51	51	51	51
Three phase CT connected	62	53	54	54	54	55

8.5 Forecast capital expenditure

Table 14 shows our forecast capital expenditure, which has been built up in the attached standardised metering capex and opex model.[17]

TABLE 14 FORECAST CAPITAL EXPENDITURE ($M 2026)

CATEGORY	2026/27	2027/28	2028/29	2029/30	2030/31
Metering	40	42	45	45	46
IT	8	3	1	2	0
Communications	2	2	2	2	3
Other	-	-	-	-	-
Total	**50**	**47**	**48**	**50**	**49**

8.6 Roll forward of the RAB to 1 July 2026

Table 15 shows roll forward of the regulatory asset base (RAB) to 1 July 2026 using the AER's roll forward model (RFM) which is attached.[18] Regulatory depreciation for the purpose of the roll forward of the RAB over 2021-26 is based on straight line depreciation of forecast net capital expenditure and the weighted average remaining life method, consistent with the AER's 2021-26 distribution determination.

Inflation indexation of the RAB is based on actual lagged inflation using an estimate for 2025-26.

[17] See UE MOD 12.03 - Standardised metering capex and opex - Jan2025 - Public
[18] See UE MOD 12.02 - Metering RFM - Jan2025 - Public

Net capital expenditure is based on actual net capex from 2021-22 to 2023-24, and estimated capex for 2024-25 and 2025-26.

Net capex and inflation estimates will be updated with the latest available information for the purposes of the AER's draft and final determinations.

TABLE 15 ROLL FORWARD OF THE RAB TO 1 JULY 2026 ($M NOMINAL)

STEP	TOTAL
1 July 2021 opening RAB from previous determination	134
Add: True-up for 2020 and 1H 2021 capital expenditure	0.3
Add: Actual/estimated net capital expenditure for 2021–2026 (including half-year WACC)	60
Less: Forecast straight-line depreciation for 2021–2026	97
Add: Adjustment for actual inflation for 2021–2026	0.1
1 July 2026 opening RAB	**98**

8.7 Asset classes and standard asset lives

We propose to apply the same asset classes and standard asset lives for 2026–31 as applied over 2021–26.

Table 16 shows our proposed asset classes and standard asset lives.

TABLE 16 PROPOSED STANDARD ASSETS LIVES FOR 2026–31

ASSET CLASS	YEARS
Metering	15
IT	7
Communications	7
Other	7

8.8 Forecast regulatory depreciation

We propose to use the same depreciation approach for 2026–31 as 2021-26, including that regulatory depreciation for establishing the closing RAB value as at 30 June 2031 be based on straight-line depreciation of actual net capital expenditure using the weighted average remaining life method and actual lagged inflation indexation of the RAB. This is consistent with the final 2026–31 AER F&A paper.

Table 17 show forecast regulatory depreciation calculated in the AER's PTRM which is attached.[19]

TABLE 17 FORECAST REGULATORY DEPRECIATION ($M NOMINAL)

DEPRECIATION	2026/27	2027/28	2028/29	2029/30	2030/31
Straight-line depreciation	14	19	24	28	33
Less: inflation indexation on opening RAB	3	4	5	6	7
Regulatory depreciation	**12**	**16**	**19**	**23**	**27**

8.9 Forecast RAB roll forward

Table 18 shows our forecast RAB roll forward from 1 July 2026 to 30 June 2031 using the AER's PTRM which is attached.[20]

TABLE 18 ROLL FORWARD OF THE RAB OVER 2026–31 ($M NOMINAL)

RAB	2026/27	2027/28	2028/29	2029/30	2030/31
Opening RAB	98	140	174	208	242
Forecast net capital expenditure	54	50	53	56	57
Forecast regulatory depreciation	12	16	19	23	27
Closing RAB	140	174	208	242	272

8.10 Meter exit fees

Meter exit fees are charged for each meter at a premises where the customer moves to a competitive meter services provider, or when a site is converted to an embedded network.

Meter exit fees are calculated in a sheet which has been added to the AER's PTRM which is attached.[21]

Table 19 shows proposed meter exit fees which would be charged over the 2026–31 regulatory period.

[19] See UE MOD 12.01 - Metering PTRM - Jan2025 - Public
[20] See UE MOD 12.01 - Metering PTRM - Jan2025 - Public
[21] See UE MOD 12.01 - Metering PTRM - Jan2025 - Public

TABLE 19 METER EXIT FEES ($ NOMINAL, GST EXCLUSIVE)

	2026/27	2027/28	2028/29	2029/30	2030/31
Single phase meter	297	347	390	431	470
Three phase DC	356	422	481	538	591
Three phase CT	481	581	675	766	851
Basic or MRIM all	68	70	73	76	79

A Appendix: control mechanism for metering services

The following control mechanism for metering services is extracted from the final AER F&A paper.

Formula	Equation	where
1.	$\mathrm{TARM_t} \geq \sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij}\, q_t^{ij}$	$i = 1, \dots, n$ $j = 1, \dots, m$ $t = 1, 2, 3, 4, 5$
2.	$\mathrm{TARM_t} = \mathrm{AAR_t} + \mathrm{B_t} + \mathrm{C_t}$	$t = 1, 2, 3, 4, 5$
3.	$\mathrm{AAR_t} = \mathrm{AR_t}$	$t = 1$
4.	$\mathrm{AAR_t} = \mathrm{AAR_{t-1}} \times (1 + \Delta \mathrm{CPI_t}) \times (1 - \mathrm{X_t})$	$t = 2, 3, 4, 5$
5.	$\mathrm{B_t} = \mathrm{b_t} + \mathrm{A_t}$	$t = 1, 2, 3, 4, 5$
6.	$\mathrm{b_t} = -\mathrm{O_t} \times (1 + \mathrm{WACC_t})^{0.5}$	$t = 1, 2, 3, 4, 5$
7.	$\mathrm{A_t} = a_t^1 + a_{t-1}^2 \times (1 + \mathrm{WACC_t}) + a_{t-2}^3 \times (1 + \mathrm{WACC_{t-1}}) \times (1 + \mathrm{WACC_t})$	$t = 1, 2, 3, 4, 5$
8.	$\mathrm{WACC_t} = (1 + \mathrm{rvWACC_t}) \times (1 + \mathrm{CPI_t}) - 1$	$t = 1, 2, 3, 4, 5$

where:

Variable	represents
t	the relevant regulatory year, with t = 1 being the 2026–27 financial year.
$\mathrm{TARM_t}$	the total annual revenue for metering services in year t, calculated as per formula 2 above.
p_t^{ij}	the price of component 'j' of tariff 'i' for year t.
q_t^{ij}	the forecast quantity of component 'j' of tariff 'i' for year t.
$\mathrm{AR_t}$	the annual smoothed revenue requirement in the metering Post Tax Revenue Model (PTRM) for year t.
$\mathrm{AAR_t}$	the adjusted annual smoothed revenue requirement for year t, calculated as per formulae 3 and 4 above.

B_t	the sum of annual adjustment factors, including any bespoke adjustments the AER deems necessary (through the A factor), to balance the metering unders and overs account for year t. To be decided in the distribution determination.
C_t	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.
ΔCPI_t	the annual percentage change in the Australian Bureau of Statistics' (ABS) Consumer Price Index (CPI) All Groups, Weighted Average of Eight Capital Cities[31] from December in year t–2 to December in year t–1. For example, for 2026–27, t–2 is December 2024 and t–1 is December 2025.
X_t	the X factor in year t, incorporating annual adjustments to the metering PTRM for the trailing cost of debt. To be decided in the distribution determination.
b_t	the true-up for the balance of the metering unders and overs account in year t, calculated as per formula 6 above.
O_t	the opening balance of the metering unders and overs account in year t.
$WACC_t$	the approved weighted average cost of capital (WACC) used in regulatory year t in the metering unders and overs account. The WACC is updated annually to apply actual inflation, calculated as per formula 8 above. It is also applied to true-up mechanisms to adjust for the time value of money.
A_t	the sum of bespoke adjustments, including the application of the time value of money where appropriate, calculated as per formula 7 above.
a_t^1	the bespoke adjustment '1' for year t. Formula 7 above demonstrates the application of the time value of money for different bespoke adjustments relating to different regulatory years.
$rvWACC_t$	the real vanilla WACC provided in the annually updated metering PTRM for year t.

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