

# Gas networks in transition: Modelling results

Australian Energy Market Commission

17 March 2026



**FINAL REPORT**

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## 1. APPROACH

### 1.1. MODEL PURPOSE

Through the *Gas Networks in Transition* rule change process, the Australian Energy Market Commission (Commission) is exploring whether changes to the existing regulatory framework for gas distribution networks are needed, given the uncertainty about their future role in supplying gas to households and small commercial customers.

To support the Commission's analysis, we have developed a simple Excel model based on the Australian Energy Regulator's (AER) post-tax revenue model (PTRM) to illustrate the impact of different combinations of regulatory settings on network users and gas distribution service providers, under different demand scenarios.

The purpose of the model is to:

- understand the impact of declining demand on illustrative gas distribution networks and customers; and
- understand to what extent different applications of regulatory levers could potentially mitigate these impacts.

The purpose of the modelling exercise does not include:

- projecting gas demand, gas distribution network costs or gas distribution network charges;
- quantifying the costs of reform options; or
- quantifying the benefits of reform options in absolute terms (although the modelling outputs will inform the Commission's assessment of the *relative* benefits of different approaches).

The purpose means that the modelling needs to:

- capture a range of plausible future demand and costs, in order to test the impact of regulatory reforms against the **breadth of demand pathways** that could arise in future – rather than focussing on specific distribution networks and a limited range of scenarios; and
- be sufficiently granular to understand the **key advantages and disadvantages** of reform options – but without replicating all the complexities of the existing regulatory framework.

### 1.2. MODELLING APPROACH

#### Model outputs

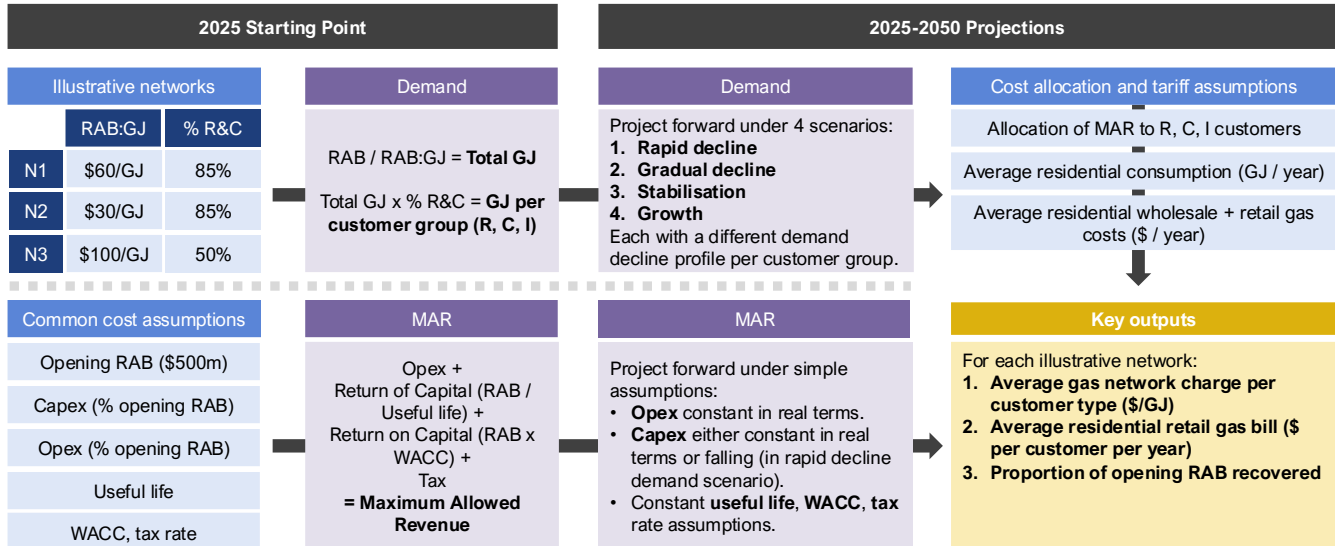
The key outputs that the Commission requires are **customer impacts** – represented by distribution network charges and customer bills – and **service provider impacts** – represented by cost recovery.

Figure 1.1 outlines that to obtain these outputs we:

1. Establish a 2024 starting point for network service provider costs and customer demand, for **three illustrative gas distribution networks**.
2. Project demand forward to 2050, under **four exogenous demand scenarios** capturing declining, stabilising and growing demand.
3. Project illustrative gas distribution network costs forward to 2050, under **simple assumptions** that are common to each network.
4. Convert projected costs into **maximum allowed revenue (MAR)**, under different regulatory settings.

5. Convert MAR to **gas network distribution charges** and **retail gas bills**, using assumptions on cost allocation, average customer consumption and the other components of retail gas bills (i.e., wholesale, retail and transmission network costs).

Figure 1.1: Model on a page



Source: CEPA.

We expand on three key elements of the modelling approach below: the use of **illustrative networks**; the use of **exogenous demand scenarios**; and the treatment of **alternative regulatory framework assumptions**.

### Illustrative networks

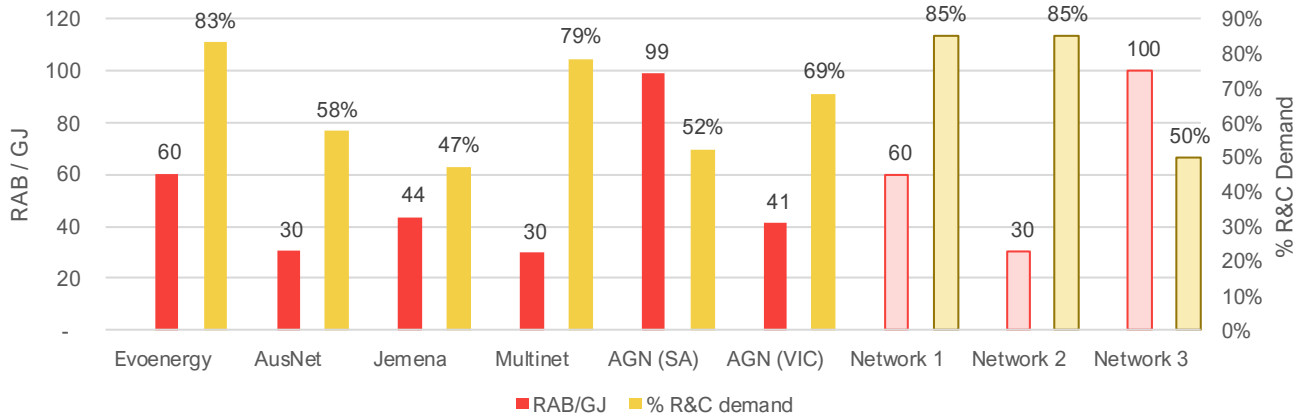
Gas distribution service providers have a range of cost structures, that reflect the characteristics of their geography and customer base – including different combinations of residential, commercial and industrial loads. The future expenditure requirements of the service providers also vary, driven by the age and condition of existing assets, and anticipated future demand. This means that changing demand conditions will impact service providers and their customers in different ways, depending on their starting point and anticipated demand trajectory.

In consultation with the Commission, we have chosen to capture this diversity by defining three **illustrative gas distribution networks** in the modelling. The illustrative networks differ with respect to two key features: **Capital Base:GJ** and **% residential and commercial (R&C) demand**.

Capital Base: GJ	% R&C demand
This captures differences in gas distribution network cost structures.	This captures residential and commercial customer gas consumption (in GJ) as a proportion of total demand.
All else equal, gas distribution networks with a lower capital base per unit of demand are likely to be more resilient to distribution network charge increases driven by declining demand, because the existing capital base is spread among a relatively larger demand base.	All else equal, gas distribution networks with higher industrial demand are likely to be less affected by declining demand. This is because industrial demand is expected to remain more stable than residential/commercial demand, as industry has less alternative fuel sources.
For example, this suggests a greater ability to recover a larger proportion of the capital base before network charges hit a switching point that could trigger price-driven reductions in gas consumption and connections.	A relatively larger industrial base, that has a lower propensity for volume and connections decline, will remain to help pay down the starting capital base before prices hit a switching point for residential and commercial customers.

We have selected **three combinations** of Capital Base:GJ and % R&C demand that broadly represent the combinations that we can observe from the 2023-24 regulatory information notices (RINs) submitted by regulated service providers to the AER – see Figure 1.2.<sup>1</sup>

Figure 1.2: Network characteristics – comparing real world networks to the illustrative networks



Source: CEPA, analysis of 2023-24 RIN data.

The illustrative networks define the **starting conditions**. From that point we:

1. Apply a **common opening capital base assumption** of \$500m (real \$2024) to derive total demand (GJ) for each illustrative network (i.e., total demand is scaled based on the capital base and Capital Base:GJ assumption).
2. Apply the assumed proportion of residential, commercial and industrial customer demand to total demand to derive assumed **demand per customer group**. This scaling targets per customer consumption and average bills to levels that we can observe in real-world benchmarks.
3. Project demand forward under the four chosen demand scenarios (Section 1.4.1) and project costs forward under simple assumptions (Section 1.4.3).

Applying common opening capital base, demand and cost scenarios to all three illustrative networks helps to compare the modelling results. For example, this allows us to compare how gas distribution networks with different starting positions – and their customers – may be impacted by a given demand trajectory, all else equal.

## Exogenous demand scenarios

The projected decline in gas demand on distribution networks is driven by a number of factors, including decarbonisation, government policy and consumer choice. As customers reduce consumption or disconnect, distribution network charges for remaining customers are expected to increase. This may prompt further demand reductions / disconnections. A pattern of falling demand leading to higher prices and further reductions in demand could become self-reinforcing (a ‘price spiral’).

Conceptually, we can describe this dynamic by defining a ‘customer disconnection condition’ (Box 1), that estimates when the benefits of electrification (i.e., avoided gas charges) become higher than the fixed cost of electrifying (all in present value terms). If we can make reasonable assumptions about the variables shown in Box 1, we can assess what level of distribution network charges might be likely to trigger price-driven disconnections or volume reductions. This can be thought of as a ‘switching point’ – i.e. beyond this level of distribution network charges, the risk of a price spiral becomes material.

<sup>1</sup> 2024-25 RIN data had not been published at the time of this analysis and may be considered in future updates.

**Box 1: Represent customer price response in demand projections**

The equation below represents, in simple terms, when **avoided gas charges > cost of electrification**:

$PV [A + (X \times Q)] > PV [Y \times T \times Q] + F$ , where

PV = Present value (based on assumed customer discount rate)

A = Gas fixed charge (distribution network + transmission network)

X = Gas variable charge (distribution network + transmission network + wholesale price + retail margin)

Q = Annual gas demand

F = Fixed cost of switching from gas to electricity

Y = Electricity variable charge (wholesale + retail + variable network)

T = Gas to electric conversion factor to make 1 GJ gas equivalent to 1 kWh electricity.

Ideally, we would like our demand projections to represent this relationship **dynamically** – that is, build a feedback loop into the modelling such that when distribution network charges rise beyond a certain threshold (given assumed values for the other parameters in Box 1) demand responds. This would in turn impact projected gas distribution network charges in subsequent years, and so on. This would allow the modelling to reflect the impact of a price spiral on distribution network charges and cost recovery.

However, in practice incorporating this dynamic into the modelling is challenging. For example:

- In practice, not all customers would disconnect when the estimated switching point is reached – due to imperfect information (e.g., different expectations regarding future prices), customer preferences, the age of their gas appliances, and other factors.
- The switching point might not be stable – and could be affected by prior changes in prices.

To be realistic, the dynamic demand response modelling would need to account for these behavioural effects. As evidenced in recent access arrangement determinations, deriving these behavioural inputs in an objective way is complex and can be contentious.<sup>2</sup>

For this reason, we have adopted a simple **static** approach to considering how distribution network charges and gas demand interact. Under this approach we:

1. Apply exogenous demand scenarios, informed by service provider forecasts from recent access determinations<sup>3</sup> and the Australian Energy Market Operator’s (AEMO) Gas Statement of Opportunities (GSOO), to project demand forwards from our 2025 starting point. By ‘exogenous’, we mean that demand is determined in the model upfront and is not influenced by modelled distribution network charges.
2. Observe the resulting distribution network charges and residential customer bills.
3. Compare modelled residential customer bills to an illustrative switching point range, derived from the Commission’s *Price trends* analysis (Box 2).<sup>4</sup> When customer bills fall above the mid-point of the switching point range, we assume that there is an increased risk of further price-driven demand reductions.

<sup>2</sup> For example, in its draft decision on Evoenergy’s 2026-2031 access arrangement, the AER expressed concerns regarding the reliability of survey data on customer preferences. AER (2025), *Draft decision – Attachment 4 – Demand*, November 2025, pp.9-10.

<sup>3</sup> For example, forecasts provided as part of Evoenergy’s 2026-31 access arrangement.

<sup>4</sup> The Commission provided underlying data drawing from their use of the underlying *Price trends* model to determine switching point ranges on the basis of electrification payback periods

4. Observe how alternative regulatory options change the timing of when the assumed switching point is reached, whether this allows for a greater level of cost recovery by service providers before that date, and the associated impact on customer bills.

### Box 2: Assumed switching point range

In 2025, using data from Energy Made Easy, the Commission estimates the average retail gas bill for residential customers, across all capital cities, was \$2,338, including standing charge of \$359. Drawing on assumptions around the costs of electrification from the *Price trends* analysis, the Commission has further estimated that:

- If the standing charge increases to \$539 (total retail bill = \$2,461 in 2025 prices), the payback period for electrifying would be 6 years, rather than 9 years under the average 2025 bill.
- If the standing charge increases to \$1,078 (total retail bill = \$3,000 in 2025 prices), the payback period is 4 years.

We have used this information to define an assumed 'switching point range' of \$2,400-\$2,920, with a mid-point of \$2,660 (all real \$2024, aligned to the model base year). We assume that if real \$2024 retail bills for residential customer stray above the mid-point of that band, there is a greater risk of a price spiral. We apply the mid-point of the range as the constraint in our modelling, because if we were to model demand dynamically, prices would rise faster than our modelling shows – suggesting that the mid-point is a sensible assumption for when bills are more likely to approach the upper end of the range.

This is, of course, uncertain – shorter payback periods provide an indication that price-driven disconnections may be more likely within this bill range, but are by no means a definitive threshold.

We have chosen to focus the analysis on residential customers because:

- Compared to commercial and industrial customers, there is greater transparency regarding current bill levels and the costs of electrification.
- If we believe that residential customers are (i) more price sensitive than commercial or industrial customers and/or (ii) more able to switch from gas to electricity in response to price increases, then it is reasonable to expect that they will reach a switching point sooner.<sup>5</sup>
- Residential customers reflect the majority of demand on the average gas distribution network.

This approach is a simplification of the dynamics that will play out in the real world. However, the objective of this modelling exercise is not to set a price path for gas distribution network service providers, but rather to explore the impact of alternative regulatory levers. For this purpose, we consider that applying static demand scenarios is proportionate, given the complexity inherent in a dynamic approach.

## Alternative regulatory framework options

The Commission has asked us to model impacts on customers and service providers under the existing regulatory framework and a suite of policy scenarios which include alternative approaches to **depreciation profiles, asset lives, capital redundancy, remuneration of inflation, assessing efficient capex and opex**, and the **form of control**.

However, establishing a plausible 'base case' that represents the current regulatory framework is not straightforward. This is because:

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<sup>5</sup> The Centre for International Economics' (CIE) 2025 analysis for Evoenergy's 2026-31 AA provides some evidence that this may be the case. For example, the CIE found that approximately 1/3<sup>rd</sup> of residential customers and commercial customers based their switching decisions at least partly on price. However, the CIE also found that switching is more difficult for commercial customers. CIE (2025), *Appendix 2.2: The Price elasticity of demand for natural gas*, June 2025, pp. 2-3.

- Under the NGR, there is already flexibility to apply the range of regulatory ‘levers’ described above. This means that although the AER may not have applied certain levers in the past, or may have applied them in a particular way, it could change its approach in future – even if the NGR remain unchanged.
- In recent access arrangement (AA) determinations, the AER has applied a ‘price path’ approach – i.e., applying shorter asset lives to a proportion of the capital base, where this was compatible with achieving a real price path for distribution network charges that the AER considered reasonable. However, the chosen price path in each case reflected regulatory judgement in the context of specific demand and cost conditions, and jurisdictional policies. This means that we cannot readily replicate the AER’s logic to derive what real price path it would have chosen under our demand and cost scenarios.

Similarly, modelling the impact of the alternative regulatory levers also involves judgements in some cases, as there is not a single way in which a given lever could be applied.

In Section 2.1, we explain the assumptions we have adopted to represent the current regulatory framework and the Commission’s alternatives. However, readers should bear in mind that the modelling results reflect a level of discretion and subjectivity. We have highlighted where this is the case.

### **1.3. MODEL STRUCTURE**

The starting point for the model structure is the PTRM used by the AER to set gas network charges for regulated service providers. The PTRM is a ‘building block’ regulatory model, that calculates the **maximum annual revenue (MAR)** that service providers can recover from regulated charges as the sum of:

- operating costs (opex);
- the return of capital or depreciation, which recovers historic capital expenditure (capex) over an assumed economic life<sup>6</sup>;
- return on capital, calculated as the opening capital base multiplied by the allowed weighted average cost of capital (WACC);
- tax; and
- other revenues, for example related to the operation of incentive schemes.

Given the purpose of this modelling exercise, the results do not need to replicate all aspects of the regulatory framework. Accordingly, we have made some simplifications to the PTRM to reduce the complexity of the model. These simplifications include:

- Assuming two asset classes – ‘existing capital base’ and ‘future capex’.
- Economic lives of assets are reflected through a single weighted average remaining life (WARL) for the existing capital base and a single weighted average life (WAL) for future capex.
- Ignoring the effect of incentive schemes and cost pass-through mechanisms.
- Assuming that forecast opex and capex are equal to actual opex and capex, and that actual inflation is equal to forecast inflation.
- Not applying smoothing to charges within or between five-year AA periods.

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<sup>6</sup> In practice, the ‘regulatory depreciation’ allowance set by the AER also includes adjustments to account for the remuneration of inflation.

- Assuming that regulatory depreciation and tax depreciation are equal.<sup>7</sup>
- Model revenues based on a simple \$/GJ charging structure. In practice service providers use a range of tariff structures and components, which retailers may or may not reflect in charges for end consumers.

The model also extends the PTRM by calculating **gas distribution network charges** from MAR, based on projected demand and assumed customer characteristics.

## 1.4. MODELLING ASSUMPTIONS

The remainder of this section explains the assumptions we have applied, highlighting key areas of judgement and uncertainty.

### 1.4.1. Demand scenarios

In consultation with the Commission, we have defined four demand scenarios that reflect alternative future trajectories. The scenarios have been selected to capture a wide range of potential outcomes, rather than reflecting a judgement that these particular assumptions are more likely to eventuate than others. The scenarios and sources are described in the table below.

*Table 1.1: Demand scenarios*

Scenario	Description
<b>1. Rapid decline</b>	Rapid demand decline from commencement of model to cessation of services in 2045. Trajectory is informed by projections from jurisdictions with this target.
<b>2. Gradual decline</b>	A more gradual decline in which demand continues past 2050. Trajectory is informed by the 2025 GSOO Step Change / GSOO Progressive Change for NSW and Victoria.
<b>3. Stabilisation</b>	Relatively minor demand decline until an assumed point of stabilisation (e.g. coinciding with the potential introduction of renewable gas). Trajectory is consistent with the gradual decline scenario to 2035, then demand is held constant.
<b>4. Growth</b>	Gas demand continues on a growth trajectory of 0.5% p.a. through to 2050 (all customers).

*Source: CEPA.*

In all scenarios, we have assumed that the demand trajectory for residential and commercial customers is the same. This is consistent with the GSOO forecasts, which combine residential and commercial demand. We also observe that some forecasts applied in recent service provider AA determinations have also assumed the same rate of change for residential and commercial loads (e.g., AusNet, Multinet and AGN (Victoria)).

The demand forecast for each gas distribution network is constructed as follows:

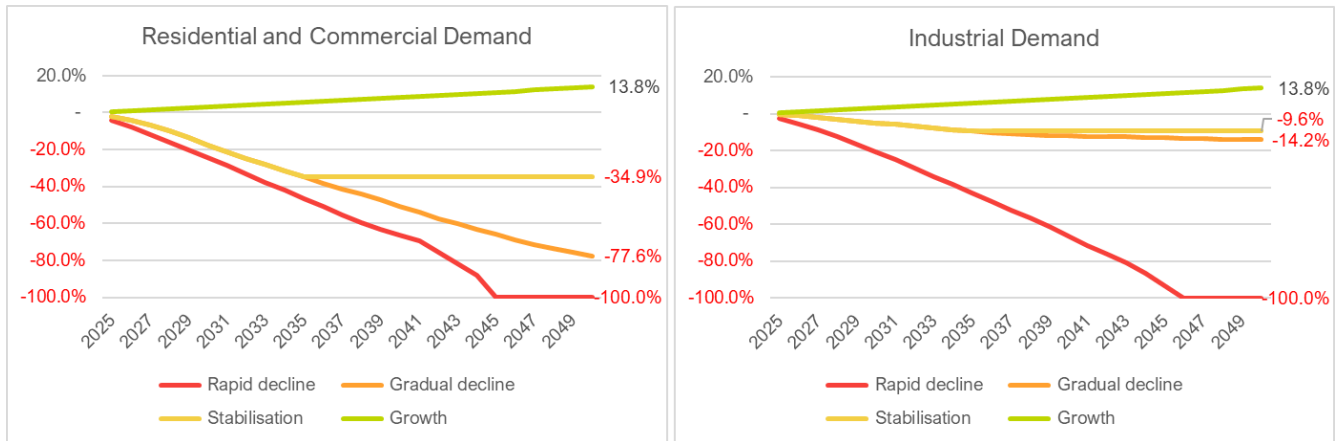
1. As described in Section 1.4.2 below, starting total demand in 2024 for each illustrative network is derived from the assumed opening capital base (the same for all illustrative networks) and the assumed Capital Base:GJ ratio (which is different for each network).
2. Total demand is then divided into residential, commercial and industrial customer classes, based on assumed shares for each group.

<sup>7</sup> In practice, tax depreciation is calculated on a different basis to regulatory depreciation. The PTRM uses the diminishing value method, rather than the straight-line method, for tax depreciation. In addition, the tax standard life is not always the same as that used for regulatory depreciation. Although the tax depreciation approach impacts the modelled tax allowance, we do not believe that assuming tax depreciation equals regulatory depreciation will impact the comparison of the regulatory options the Commission is considering.

3. The demand scenarios define a cumulative % change from this starting point, for each customer group. This means that the trajectory of total demand on each illustrative network varies, because rates of change for each customer group are different. In particular, in the two scenarios with declining demand, industrial customer usage is assumed to decline more slowly than that of residential / commercial customers.

The figure below presents the assumed cumulative change in demand from 2024, for each customer group under each scenario.

Figure 1.3: Demand scenarios – Cumulative change from 2024 demand



Source: CEPA.

### 1.4.2. Illustrative network starting point

The table overleaf sets out the assumed starting Capital Base:GJ and % R&C demand assumptions for each illustrative network. The table also shows the resulting assumptions for total customer demand, given the assumed opening capital base and Capital Base:GJ.

Table 1.2: Illustrative network characteristics

Network	Network 1	Network 2	Network 3
Capital Base: GJ (real \$2024)	60	30	100
Opening Capital Base (real \$2024)	\$500m	\$500m	\$500m
Total TJ (2024)	8,333	16,667	5,000
% residential demand	60.0%	60.0%	35.0%
% commercial demand	25.0%	25.0%	15.0%
% industrial demand	15.0%	15.0%	50.0%
% MAR – residential	94.0%	94.0%	80.0%
% MAR – commercial	4.0%	4.0%	15.0%
% MAR – industrial	2.0%	2.0%	5.0%

Source: CEPA.

The table also shows the associated assumptions for the proportion of MAR that is allocated to each customer group. For Networks 1 and 2, with a relatively higher proportion of residential and commercial demand, the corresponding allocation of revenue is also higher, compared to Network 3. These assumptions reflect our analysis of 2023-24 RIN data, which indicate that the proportion of MAR recovered from each customer group broadly aligns to their relative contribution to total demand (GJ). This is a simplification, as in practice service providers adopt more complex revenue allocation methods. Further, we have assumed that the proportion of MAR recovered from each customer group remains constant over time. In practice, the allocation of MAR could vary over time, to reflect the different rates at which demand from each group changes.

### 1.4.3. Future expenditure

In this sub-section we explain how we have modelled future opex, capex and depreciation for the set of stylised networks.

#### Operational expenditure (opex)

There are two assumptions that determine opex in the model:

- Firstly, the starting point for opex, which is represented in the model as a % of the capital base.
- Secondly, how this opex is trended over the forecast period.

For the first assumption, we assume that for the illustrative networks opex starts at 5% of the capital base. This closely matches the historical positions for the average gas distribution network (based on RIN data from 2010-11 to 2023-24).

For the second assumption, we hold real opex constant for the forecast period. This is also aligned to the historical outturn result for the average service provider in the RIN data. A constant opex level may be broadly realistic, even where demand is declining, if the service provider is required to maintain the existing network in operation. However, particularly in the rapid decline scenario (where demand for all customer groups falls to zero by 2045) at some point we might expect to see decommissioning of parts of the distribution network – and a corresponding real reduction in opex.<sup>8</sup> At the same time, there is limited evidence on which to base an assumed decommissioning scenario – and the impacts of declining demand on opex may vary across service providers. For this reason, we have maintained the constant real opex assumption – but note that in the later years of the forecast period, it may be an overestimate.

<sup>8</sup> Although, decommissioning processes may also require short-term increases in opex.

## Capital expenditure (capex)

We have considered capex assumptions across the five RIN reporting categories:

- Connections
- Augmentation expenditure (augex)
- Replacement expenditure (repex)
- Other capex (including telemetry, ICT, other capex and overheads).
- Meter replacement.

For the illustrative networks, we assume no connections capex or augex. We assume that the recent rule change by the Commission<sup>9</sup> will mean that connections capex and augex is entirely funded by upfront capital contributions from customers, from 2025 onwards.

We represent the remaining capex categories as a flat 2.65% of the opening capital base at the start of the forecast period. In practice, across the historical period captured by the RIN data, the value of this capex as a proportion of the capital base has varied – both across service providers and over time. Nonetheless, the 2.65% assumption reflects:

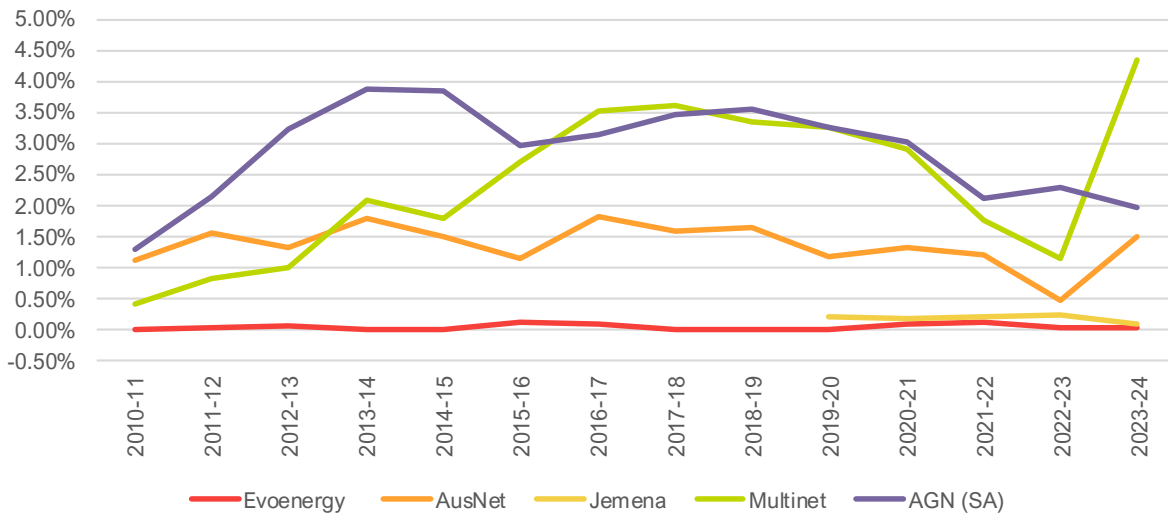
- For **other capex**, an assumption of 1.25% of the capital base, which matches recent historical experience.
- For **meter replacement**, an assumption of 0.4% of the capital base, which broadly matches recent historical experience. This may be an oversimplification, as meter replacement capex may vary with the total customer base. Indeed, the historic data indicates that as the customer base expands, the total capital spent on meter replacement has increased. Accordingly, over time as customer numbers decline, we might instead expect meter replacement capex to fall – rather than remain constant.
- Finally, for **repex** an assumption of ~1.0% of the capital base aims to capture the regular periodic requirements of a network that is *not* in a major mains replacement cycle. As shown in the figure below, an appropriate *illustrative* repex assumption is difficult to determine, because historic profiles have varied so widely – reflecting different asset types, conditions and replacement strategies across the service providers. This means that a flat percentage of the capital base assumption is unlikely to be representative of any actual service provider. Accordingly, as a sensitivity, we have modelled a temporary (10 year) repex uplift – an additional 1.5% of the opening capital base – to capture the illustrative impact of a significant mains replacement profile.

While these assumptions are stylised, we consider that they provide a reasonable basis given the purpose of this modelling exercise – which is not to precisely estimate efficient capex requirements over the next three decades, but rather to assess the impact of alternative regulatory settings across a spectrum of possible future states.

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<sup>9</sup> AEMC (2025), [National Gas Amendment \(Updating the regulatory framework for gas connections\) Rule 2025](#).

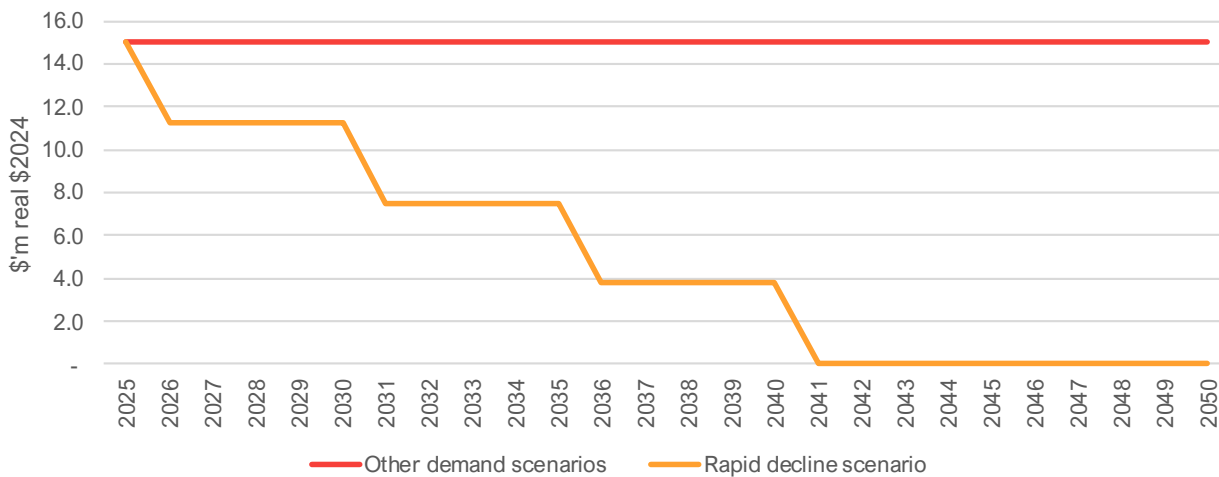
Figure 1.4: Repex as a percentage of opening capital base



Source: CEPA analysis of RIN data.

The approach outlined above – that capex is held constant in real terms at 2% of the opening capital base – applies to the gradual decline, stabilisation and growth demand scenarios. In the rapid decline demand scenario, we instead assume that capex steps down gradually in each five-year AA period, such that there is no capex incurred in the last five years to 2045. This is shown in the figure below.

Figure 1.5: Capex assumptions under each demand scenarios (real \$2024)



Source: CEPA.

## Financial assumptions

To derive MAR for each illustrative network, we also need to apply assumptions regarding the:

- Allowed WACC – which is used to derive the return on capital. We have assumed a value of 6.5% (nominal). This reflects cost of debt and equity assumptions taken from the AER’s 2025 Rate of Return Annual Update (RORAU), and 60% gearing assumption from the 2022 Rate of Return Instrument (RORI). We have assumed that the WACC remains constant over the forecast period.
- Inflation – which is used to index the capital base under the current regulatory framework, and to convert between real and nominal values. We have assumed an inflation rate of 2.5% p.a., reflecting the mid-point of the Reserve Bank of Australia’s (RBA) target range.

- Corporate tax rate and value of imputation credits (gamma) – which are used to derive the regulatory tax allowance. We assume a tax rate of 30% and gamma of 0.57%, taken from the 2022 RORI and 2025 RORAU respectively.
- Economic life of the existing capital base and future capex – which are used to determine depreciation. These assumptions are discussed further below.

To derive illustrative economic life assumptions, we have reviewed the asset lives applied in the most recent PTRMs for each of the scheme gas distribution networks regulated by the AER. This produces a range of weighted average asset lives for each service provider, for the opening capital base at the start of the five-year AA period and for projected capital additions with that period (Table 1.3).

Table 1.3: Asset lives

Service provider (last year of AA)	Weighted Average Remaining Life (WARL) – Opening Capital Base	Weighted Average Life (WAL) – Forecast capex
Evoenergy (2030-31)	20 years	17 years
AGN (SA) (2030-31)	41 years	46 years
Jemena (2029-30)	33 years	26 years
AusNet (2027-28)	32 years	44 years
AGN (VIC) (2027-28)	37 years	38 years
Multinet (2027-28)	30 years	42 years
<b>Minimum</b>	<b>20 years</b>	<b>17 years</b>
<b>Maximum</b>	<b>41 years</b>	<b>46 years</b>
<b>Average</b>	<b>32 years</b>	<b>35 years</b>
<b>Average – excluding Evoenergy</b>	<b>34 years</b>	<b>39 years</b>

Source: CEPA analysis of PTRM data.

Based on this data, for the **opening capital base** of each illustrative network, we apply a standard WARL of 35 years. When modelling the current regulatory framework (see Section 2.2), we then apply a shorter asset life (5 years) to a proportion of the opening capital base – with that proportion set to reflect the AER’s recent AA decisions where asset life shortening has been approved. The remaining portion of the existing capital base continues to be depreciated in line with a 35-year asset life.

For **future capex**, we have applied the WAL assumptions below to the illustrative networks under the various demand scenarios. The rapid decline scenario reflects the PTRM parameters applied for Evoenergy. The stabilisation / growth scenarios reflect the average PTRM values for the other service providers. The gradual decline scenario assumption reflects the average of these two points.

Table 1.4: Future capex asset life assumptions for illustrative networks

Demand scenario	Weighted Average Life (WAL) – Forecast capex
<b>Rapid decline</b>	17 years
<b>Gradual decline</b>	28 years
<b>Stabilisation / growth</b>	39 years

Source: CEPA.

The WAL assumptions shown in the table above are *maximum* asset lives. In the rapid decline scenario, in some cases this would lead to future capex not being fully depreciated before demand falls to zero (i.e., capex from 2028

onwards). In that scenario, we shorten the asset life for new capex to match the remaining period to 2045. This reflects an assumption that new capex would not be incurred unless it can be recovered within that period.

#### **1.4.4. Retail bills**

As outlined in Section 1.2, we have compared modelled retail bills (in real \$2024) for residential customers to an illustrative switching point range, in order to understand when the risk of price-driven demand reductions could become material, under the various scenarios examined.

To derive modelled residential retail bills, we:

1. Set our starting 2025 retail bill equal to the Commission's *Price trends* estimate of the NEM-wide average (\$2,338, nominal).
  - a. The distribution network charge component varies across the illustrative networks, driven by the opening capital base, WACC and cost assumptions.
  - b. The wholesale charge component is set based on the Step Change gas price forecast informed by the 2025 GSOO, and an assumption average gas consumption per residential customer.
  - c. The remaining components of retail bills – including retail margin, retail costs and transmission network costs – are treated as a single fixed amount and set such that the total retail bill in 2025 is \$2,338 per customer (nominal).
2. Derive a forecast retail bill to 2050 by:
  - a. Varying the distribution network charge component in line with projected MAR, assumed cost allocation and customer demand assumptions.
  - b. Holding the wholesale charge component and assumed gas consumption per customer constant. Specifically, we assume an average wholesale gas price of \$13/GJ (real \$2024), that remains constant in real terms.<sup>10</sup>
  - c. Holding the starting 2025 value for other bill components constant in real dollar terms. That is, if the starting value for these other components in 2025 is \$250 (real \$2024), in 2045 it is still \$250 (real \$2024).

As our modelling is based on total retail bill, we have not needed to make assumptions about the relative fixed and variable components of the network tariff, nor the role of the gas retailer in packaging these into retail products. However, in practice the structure of tariffs will have an impact on customer incentives to consume gas.

There are alternative ways in which a retail price forecast could be derived. However, we consider that scaling the starting assumptions to match the 2025 NEM-wide average provides a reasonable basis for comparison to the switching point range, that reflects relative movements in modelled distribution network charges.

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<sup>10</sup> This is the average GSOO Step Change forecast for 2025-2030. The GSOO wholesale gas price forecast is not constant over time. We have adopted a constant price so as not to obscure movements in retail gas bills that result from the approach to regulating gas distribution network charges.

## 2. MODELLING RESULTS

### 2.1. POLICY SCENARIOS

In this section, we present draft modelling results for a “base case” that aims to capture the current regulatory framework as it has recently been applied. We then explore the impact of applying the various regulatory levers in different ways, as defined in consultation with the Commission. The table below summarises each scenario that we have modelled. The sub-section for each option provides further detail on the approach and assumptions, including areas of judgement.

Table 2.1: Summary of the modelled policy scenarios

#	Policy scenario	Description
1	Base case	This scenario is a characterisation of the AER’s recent AA decisions. Key features of the scenario include (i) applying an indexed capital base, (ii) applying a straight-line depreciation profile <sup>11</sup> , and (iii) at the start of each 5-year AA period, assuming that a proportion of the opening capital base is depreciated over a shorter period (5 years) compared to the standard WARL (35 years). The capital base proportion is based on the AER’s recent AA decisions and varies with the demand scenario.
2	Reprofiled depreciation	This scenario illustrates the impact of two alternatives to a straight-line depreciation profile: sum-of-digits and declining balance. In both cases, the assumed asset life for the opening capital base is 35 years (i.e., none of the existing capital base is assumed to be depreciated over a shorter period).
3	Shortened asset lives	This scenario assumes that, compared to the base case, shorter economic asset lives are applied to a larger proportion of the opening capital base in each AA period. The proportion of the opening capital base is broadly set to recover more of the existing capital base, while holding residential retail bills below the assumed switching range mid-point for as long as possible.
4	Partial capital redundancy	This scenario extends Scenario 3, by assuming that redundancy is applied alongside shortened asset lives to maintain residential retail bills below the assumed switching point for longer (where possible). Capital redundancy is applied after asset lives have been shortened per Scenario 3, and from the point that retail bills start to rise above the switching range mid-point, but not before.
5	Capital base indexation	Under the current regulatory framework, the capital base is indexed annually in line with inflation and service providers receive a real rate of return on the capital base. <sup>12</sup> Alternatively, service providers could be remunerated for inflation by applying a nominal rate of return to an unindexed capital base. Compared to an indexed capital base approach, an unindexed capital base reduces the extent to which cost recovery is deferred to later years.

<sup>11</sup> When using the term ‘straight line depreciation’ in this report, we mean that an initial depreciation allowance is calculated as the capital base divided by an assumed asset life. As described in the footnote below, under the current regulatory framework an amount is then deducted from the regulatory depreciation to ensure that the service provider is not remunerated twice for inflation. This means that in practice, the regulatory depreciation allowance *inclusive* of this adjustment is not ‘straight line’.

<sup>12</sup> In practice, the AER achieves this outcome through the application of a nominal rate of return to an inflation-indexed capital base. A deduction is then made to the regulatory depreciation allowance, to remove the expected level of inflation that is reflected in the nominal rate of return. This adjustment is to avoid double counting the allowance for inflation. This approach results in the same outcome as a real rate of return applied to an indexed capital base.

#	Policy scenario	Description
6	Combined	This scenario tests a combination of regulatory levers – shortened asset lives (to the same extent as applied under the base case – Scenario 1), reprofiled depreciation (applying the sum of digits method – Scenario 2) and an unindexed capital base (Scenario 5).
7	Capex and opex criteria	The National Gas Rules (NGR) set out criteria to guide the AER’s assessment of efficient capex and opex. The Commission is contemplating changes to these criteria that may have the effect of more tightly controlling allowed expenditure. To illustrate the potential impact, this scenario assumes that relative to the base case, a cumulative 1-2% per annum reduction is applied to forecast capex and opex.
8	Revenue cap	Some service providers are currently regulated under a hybrid price cap. Under this approach, service providers are exposed to demand forecast errors within a band of +/- 5%, but share the impact of variations outside of this range with consumers. Alternatively, under a revenue cap, service providers’ allowed revenues would be adjusted annual to fully offset the impact of demand variations (in net present value terms). This scenario compares the hybrid price cap and revenue cap approaches.

Source: CEPA.

We have explored various combinations of the policy scenarios under the four demand trajectories, for each of the three illustrative networks. This produces a very large number of model runs. Accordingly, the discussion below focusses on a selection of modelling results to illustrate key features of the policy scenarios.

## 2.2. SCENARIO 1: BASE CASE

We have represented the AER’s recent AA determinations by, at the start of each 5-year AA period, applying a shorter economic life (5 years) to a proportion of the capital base, compared to the assumed standard WARL (35 years). The proportion varies according to the demand scenario – for example, shorter asset lives apply to a larger percent of the opening capital base in the rapid decline scenario. Depreciation is calculated on a straight-line basis (before the impact of the inflation adjustment to derive the regulatory depreciation allowance).

The proportion of the capital base subject to asset life shortening is set as follows:

1. In the first AA (2026-2030), this aims to broadly reflect the AER’s recent decisions (draft and final) on shorter asset lives, considering the proportion of the capital base to which asset life shortening applies (Table 2.2). Because the AER’s decisions were based on different cost and demand assumptions to our illustrative networks, this does not necessarily produce the same real price path – in this sense, the base case scenarios may not represent what the AER would actually do in practice. However, it provides us with a starting point to assess the impacts of applying shorter asset lives to a larger portion of the capital base in Scenario 3. No asset life shortening applies in the stabilisation / growth scenarios.<sup>13</sup>
2. When applied in the first AA period, these assumptions produce a higher level of allowed revenues, compared to that arising from straight-line depreciation applied over the standard WARL of 35 years.
3. In subsequent AAs, we apply further asset life shortening to the same proportion of the capital base, where this does not bring forward the time when the assumed switching point is reached. In some of our modelled scenarios, applying asset life shortening beyond the first AA is not possible given this constraint.

<sup>13</sup> Except for Network 3 under the stabilisation demand scenario.

Table 2.2: Recent AER determinations - asset life shortening

AER decision	Asset life shortening (% opening capital base)
Evoenergy 2026-31 (draft)	10%
Ausnet 2023-28	6%
AGN (SA) 2021-26	0%
Jemena 2025-30	1%
Multinet 2023-28	4%
AGN (VIC) 2023-28	10%
<b>Assumption – Rapid decline</b>	AA1 – 10% (2.5% for Network 3) AA2 – 5% Network 1, 10% Network 2 AA3 – 2.5% Network 2 only
<b>Assumption – Gradual decline</b>	AA1 – 5% AA2 – 5% (Network 1 and 2 only) AA2 – 5% Network 2 only

Source: CEPA analysis.

Although we have aimed to make the base case scenario broadly consistent with the above outcomes of past AER decisions, this is an imperfect representation of the AER's historic (and future) approach under the current NGR. Accordingly, the base case scenario is not a *prediction* of what the AER would or would not do under the current framework. Rather, it is a reference point that can help us to explore what the impact of applying regulatory levers in a different way might be.

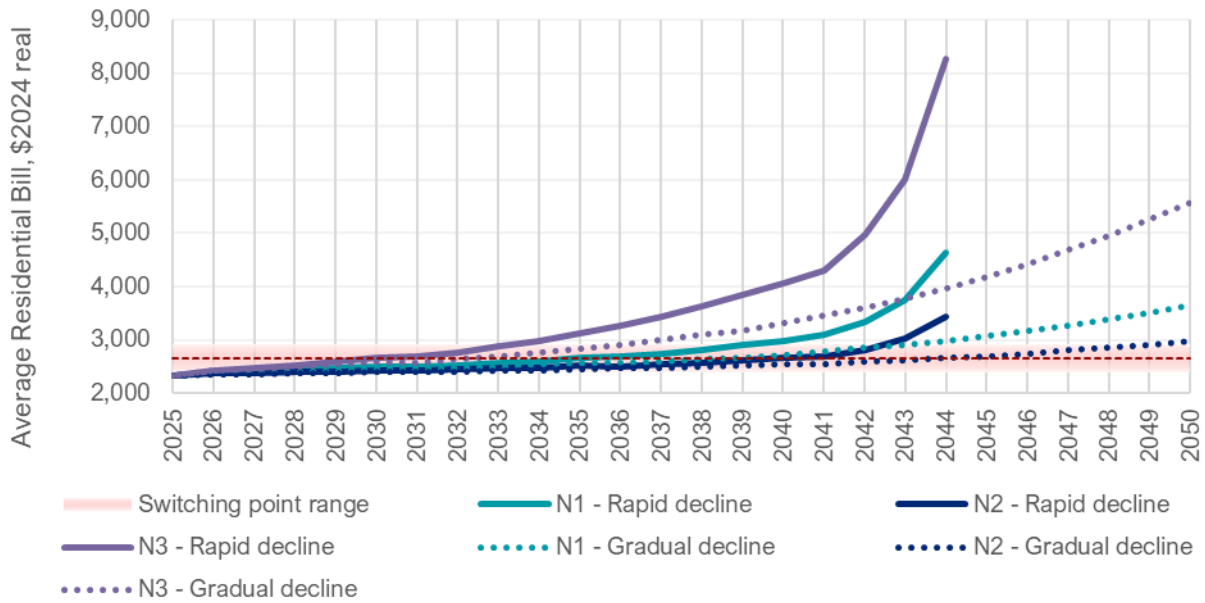
Relevantly, in its draft decision for Evoenergy's 2026-31 access arrangement the AER commented that "*While accelerated depreciation can be used as a tool for reducing asset stranding risk, it has limitations and on its own cannot resolve the issues faced by the gas networks and customers from anticipated declining demand. Declining demand is ultimately the key driver of rising future network prices. So long as demand continues to decline, no affordable amount of accelerated depreciation will achieve long-term price stability.*"<sup>14</sup> Our application of accelerated depreciation in the base case scenario appears broadly consistent with this perspective.

The base case results for the three illustrative networks under the rapid decline and gradual decline demand scenarios are shown in Figure 2.1 and Figure 2.2 below. Under the base case assumptions, residential customer bills for all three networks stray into the switching point range during the forecast period – indicating a heightened risk that the remaining unrecovered capital base at that time could become economically stranded.

In the following discussion of policy scenarios, we focus primarily on Network 1 – as it sits roughly between the two other illustrative networks. Figure 2.2 illustrates that for Network 1, the switching point is reached in 2036 under the rapid decline case and 2038 in the gradual decline case. At these points in time, a substantial proportion of the starting capital base remains unrecovered: ~68% in the rapid decline scenario and ~82% in the gradual decline case. The more challenging outcome in the gradual decline scenario reflects differences in assumed capex: capex falls to zero by 2040 in the rapid decline case, but continues at a constant 2% of the 2025 opening capital base in the gradual decline case – even while demand still decreases materially over the period.

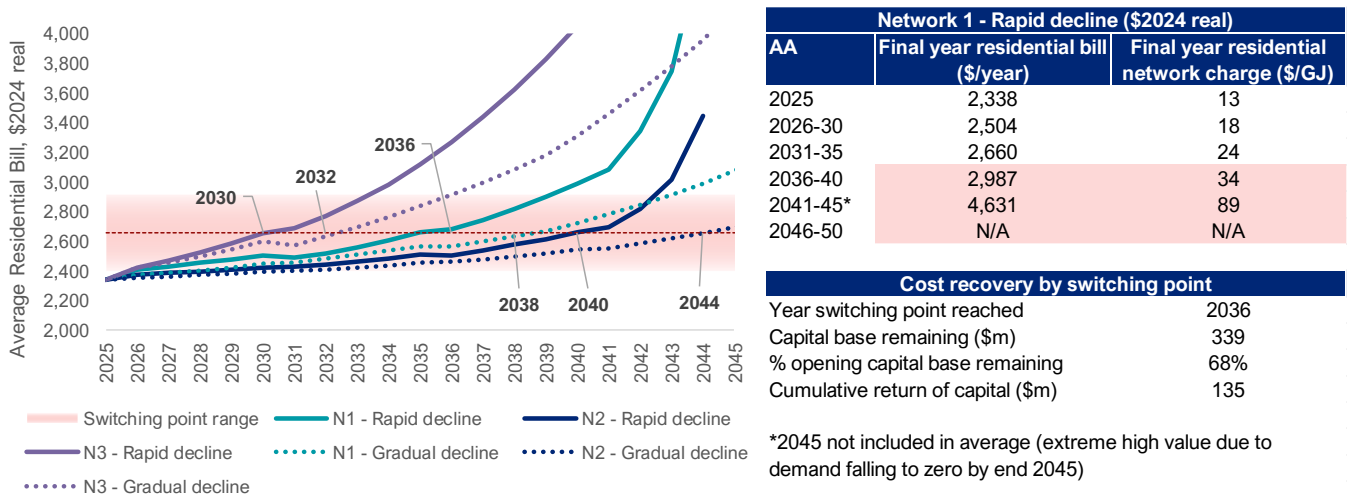
<sup>14</sup> AER (2025), *Draft decision – Attachment 1 – Capital base, regulatory depreciation and corporate income tax*, November 2025, p.15.

Figure 2.1: Base case results - Average residential customer bill



Source: CEPA analysis. Note: Y-axis starts at \$2,000.

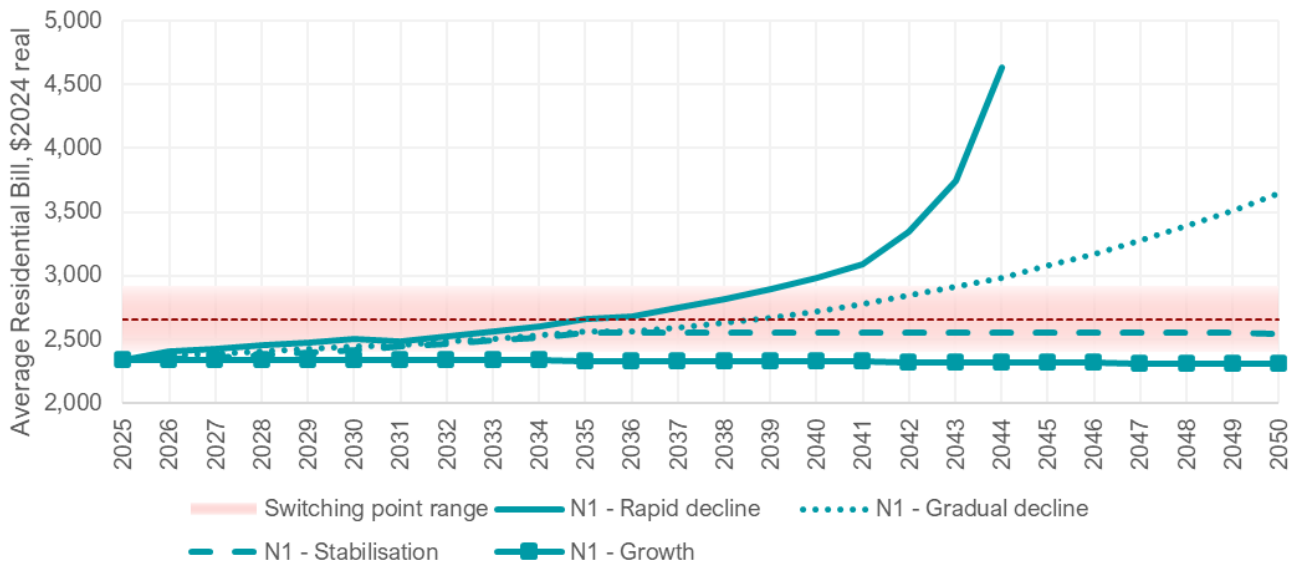
Figure 2.2: Base case results – year when retail bill exceeds mid-point of switching range



Source: CEPA analysis. Note: Y-axis starts at \$2,000.

As noted in Section 1.4.1, future demand is uncertain and the Commission is seeking to consider a range of potential future states. With this objective in mind, the figure below contrasts the rapid decline and gradual decline scenarios to the stabilisation and growth scenarios, for stylised Network 1. This illustrates that under alternative demand scenarios the assumed residential bill switching point is not breached within the modelling period.

Figure 2.3: Network 1 - Comparison of demand scenarios (impact on average residential customer bill)



Source: CEPA. Note Y-axis starts at \$2,000.

### 2.3. SCENARIO 2: REPROFILED DEPRECIATION

This scenario illustrates the impact of two alternatives to straight-line depreciation: **sum-of-digits** and **declining balance** (Box 2). In both cases, the assumed asset life for the opening capital base is 35 years (i.e., none of the existing capital base is assumed to be depreciated over a shorter period). Under a straight-line depreciation approach, this would mean that an equal portion of the opening capital base is depreciated in each of the 35 years (ignoring the adjustments to the regulatory depreciation allowance that relate to remuneration of inflation). Under the alternative approaches, more of the capital base is depreciated at the beginning of the 35-year period than at the end.

#### Box 2: Reprofiled depreciation methods

The **declining balance** method uses an ‘acceleration factor’ to calculate the portion of the asset value that is depreciated each year. To illustrate this option, we have assumed an acceleration factor of 2. Given a 35-year asset life, this means that 5.7% ( $2 / 35$ ) of the opening capital base at the start of each year is depreciated. For example, if the opening capital base in year 1 is \$100m, the depreciation is \$5.7m. In year 2 (assuming no capital additions), the opening capital base is \$94.3m and depreciation is \$5.4m, and so on. If the declining balance method produces depreciation that is lower than if the remaining capital base were depreciated using the straight-line approach, then the method switches to back straight-line depreciation. The lower the acceleration factor, the less front-loaded the profile.

The **sum-of-digits** method produces a depreciation profile that is higher in the early years and gradually declines over time. It works by allocating depreciation in proportion to the number of years of useful life remaining. For example, if an asset has a 35-year useful life, the sum of the years from 35 down to 1 is:

$$35 + 34 + 33 + \dots + 1 = 630$$

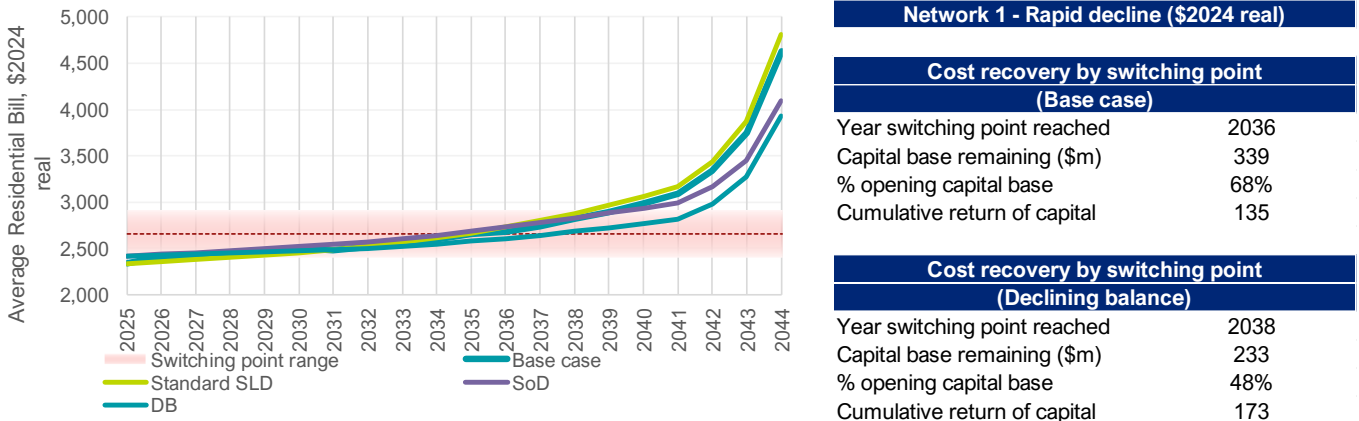
Each year’s depreciation share is then based on the number of years of life remaining at the start of that year:

- in year 1, the asset has 35 years remaining → depreciation =  $35 / 630$  of the asset value
- in year 2, it has 34 years remaining →  $34 / 630$
- in year 3,  $33 / 630$ , and so on.

Because the remaining life falls each year, the depreciation amount gradually declines over time.

While both approaches produce front-loaded depreciation relative to straight-line depreciation, the exact profile differs in each case – depending on the remaining useful life and the acceleration factor applied in the declining balance method. The results of applying these methods, compared to the base case, are shown in the figure below for Network 1 under the rapid decline scenario. For reference, we also show the ‘standard SLD’ method – i.e., straight-line depreciation over the assumed standard WARL of 35 years.

Figure 2.4: Comparison of base case and alternative depreciation profiles (Network 1, rapid decline)



Source: CEPA. Note: Y-axis starts at \$2,000. Note: The scale of the chart obscures differences between the scenarios in the earlier years. The standard SLD method remains lower than the base case up to 2030, but then rises above it to reach the switching point by 2037. The sum-of-digits approach is higher than the base case to 2038, when it reaches the switching point.

Under the modelling assumptions we have applied, applying a more front-loaded depreciation profile initially produces higher bills relative to the base case, as a larger proportion of the capital base is recovered sooner. For example, under the declining balance approach there is an immediate step up in charges in 2025: compared to the base case, the average residential retail bill is ~4% higher and the average distribution network charge is ~22% higher. It may not be plausible that such a significant increase in distribution network charges would receive regulatory approval. Accordingly, the declining balance and sum-of-digits scenarios could be viewed as somewhat theoretical ‘bookends’.

At the same time, a more front-loaded cost recovery profile reduces charges for those customers remaining on the distribution network in later years, delays when the assumed switching point is reached, and increases the level of cost recovery by that time. For example, the declining balance approach sees the switching point reached one year later than under the base case. By this time the service provider has recovered a significantly greater proportion of its 2025 opening as capital set base (given the same starting capital base and same assumed new capex).

## 2.4. SCENARIO 3: SHORTENED ASSET LIVES

This scenario assumes that, compared to the base case, accelerated depreciation is used to reflect a reduced expectation of the useful lives of the network assets. This is achieved by applying shorter asset lives to a larger proportion of the opening capital base in each AA period, relative to the base case. As in the refiled depreciation scenarios, this has the effect of recovering a larger amount of the capital base sooner – albeit via a different method. This illustrates a general feature of the alternative depreciation methods we have modelled – although the approaches can produce differing cost recovery profiles depending on the assumptions applied, they can also be used to achieve similar outcomes.

In this scenario, service providers receive increased accelerated depreciation up to the point that bill levels risk initiating a disorderly exit. This is achieved by increasing the proportion of the opening capital base to which shorter asset lives apply (compared to the base case), while holding residential retail bills below the assumed switching point threshold for as long as possible. Accordingly, the proportion varies depending on both the illustrative network (e.g., Network 3, with relatively higher starting network charges, has less room to apply shortened asset lives, before reaching the assumed switching point) and demand scenario (e.g., the switching point is reached sooner in the rapid decline scenario, compared to the gradual decline case).

For example, the scenario assumes that shortened (5-year) asset lives are applied to the following opening capital base amounts at the start of each AA period, for illustrative Network 1 under the rapid decline scenario. This means that a larger proportion of the starting capital base is recovered over a shorter period, relative to the base case.

Table 2.3: Network 1 - Rapid decline - Proportion of opening capital base subject to asset life shortening

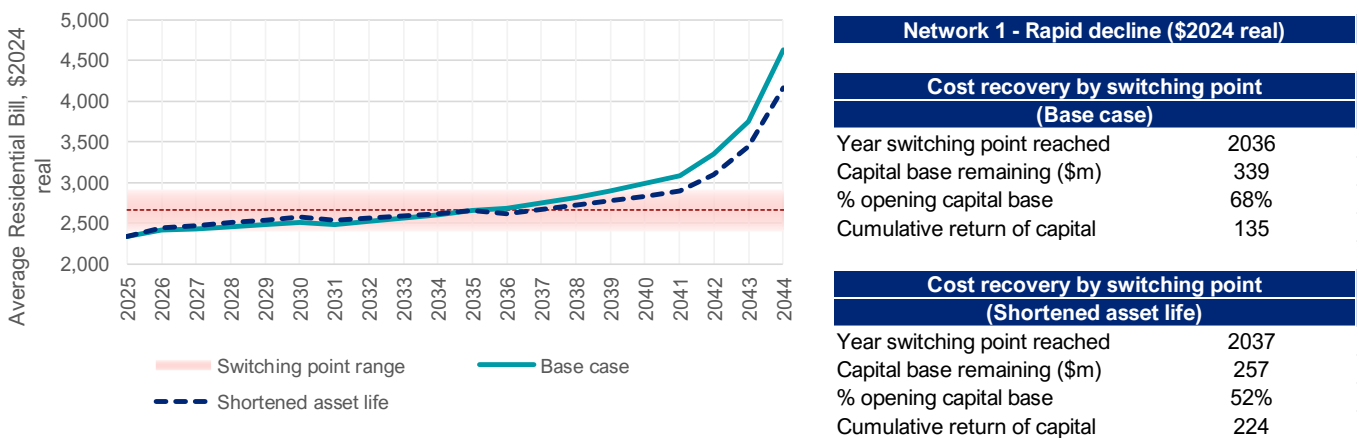
AA period	Base case	Shortened asset life scenario
2026-30	10%	14%
2031-35	5%	10%

Source: CEPA.

The figure below presents the results for illustrative Network 1, compared to the base case, under these assumptions. This illustrates that – given the modelling assumptions – applying shorter asset lives to a larger proportion of the capital base can in some circumstances hold customer charges below the switching point for a longer period. This can allow more of the capital base to be recovered before that time – providing service providers an improved opportunity to recover their return of and on capital. In particular, asset life shortening allows Network 1 to recover 48% of its opening capital base before bills reach the switching point, compared to 32% in the base case.

At the same time, although modelled retail bills remain below the assumed switching point, they are higher than the base case. By the end of the first AA, average distribution network charges are ~13% higher than the base case in real terms (~\$2/GJ), and average retail bills are 3% higher in real terms.

Figure 2.5: Comparison of base case and shortened asset life scenario (Network 1, rapid decline)



Source: CEPA. Note Y-axis starts at \$2,000.

The scenario results also illustrate a judgement we have made in applying this scenario. In practice, we can see that some headroom remains between the modelled retail bill and the assumed switching point in the earlier AA periods. Accordingly, we could have applied asset life shortening to a larger proportion of the opening capital base, to either (i) hold prices below the switching point for longer and/or (ii) recover more of the capital base before the switching point is reached.

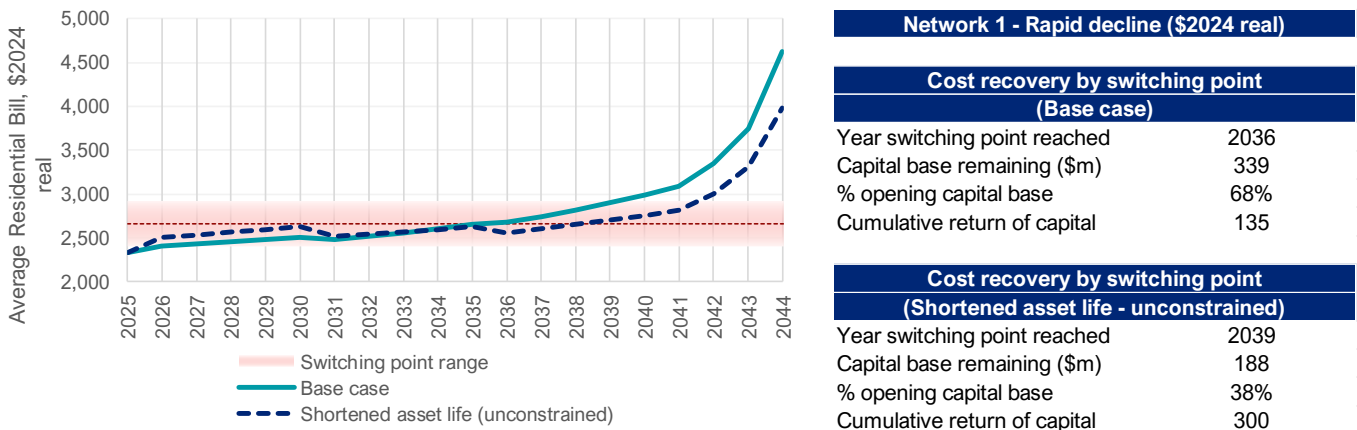
We have not done that because it would have produced a larger, earlier jump up from the current average bill. Although this may be below the assumed switching point, it is possible that a significant price shock could prompt price-driven disconnection regardless.<sup>15</sup> We also recognise that the regulator would likely ‘smooth’ large single year increases over a number of years, on an NPV-neutral basis. When applying this scenario, we have therefore capped

<sup>15</sup> For example, for a discussion of the impact of price shocks on gas consumption see: Burlinson et al (2025), *The impact of energy prices on consumers: a tale of two crises*, July 2025; Inter-American Development Bank (2023), *Does Energy Consumption Respond to Price Shocks?*, April 2023.

the real price path for distribution network charges in the first AA period at 10% p.a. This assumption is applied to illustrate the features of this scenario and does not reflect a judgement on what price uplift would be reasonable in reality. These types of judgements reflect that while applying shortened asset lives (or really any regulatory lever that advances cost recovery) is conceptually simple, there are significant practical challenges.

As a point of comparison, the figure below shows the impact of removing the 10% real price path constraint on network charges. In this scenario, shorter asset lives are applied to 26% of the opening capital base in the first AA and 16% in the second AA (compared to 14% and 10% in the constrained scenario). This pushes out the time that the switching point is reached by three years, to 2039 – and provides for a much higher level of capital base recovery. However, this means that distribution network charges in the first AA increase by 12% p.a. in real terms.

Figure 2.6: Comparison of base case and unconstrained shortened asset life scenario (Network 1, rapid decline)



Source: CEPA. Note Y-axis starts at \$2,000.

## 2.5. SCENARIO 4: PARTIAL CAPITAL REDUNDANCY

This scenario extends Scenario 3, by assuming that partial capital redundancy is applied alongside shortened asset lives to maintain residential retail bills below the assumed switching point for longer. Capital redundancy is applied from the point that retail bills start to cross into this range, but not before.

To illustrate this scenario, we focus on stylised Network 3. Compared to Networks 1 and 2, Network 3 has a higher starting network charge, due to the assumed size of its capital base compared to its customer base. Accordingly, it has less ‘room to manoeuvre’ by applying shortened asset lives to accelerate cost recovery. Given the modelling assumptions, it is not possible to apply additional asset life shortening for Network 3, compared to the base case, without reaching the switching point at an earlier date. This makes it the illustrative network most likely to see the need to apply partial asset redundancy.

Accordingly, in Scenario 4 capital redundancy is applied concurrently with shorter asset lives (Table 2.4). This allows residential bills to stay below the switching point until 2033, part way through the second access period. The amounts applied are summarised below. This means that in the first AA period, \$29m of the capital base (6% of opening value) is depreciated over a shorter period, while at the same time \$68m (14% of opening value) is removed from the capital base.

Table 2.4: Network 3 - Rapid decline - Proportion of opening capital base subject to asset life shortening and redundancy

AA	Scenario 3		Scenario 4	
	% shorter asset life	% redundant	% shorter asset life	% redundant
2026-30	2.5%	-	6.0%	14.0%
2031-35	-	-	6.0%	14.0%

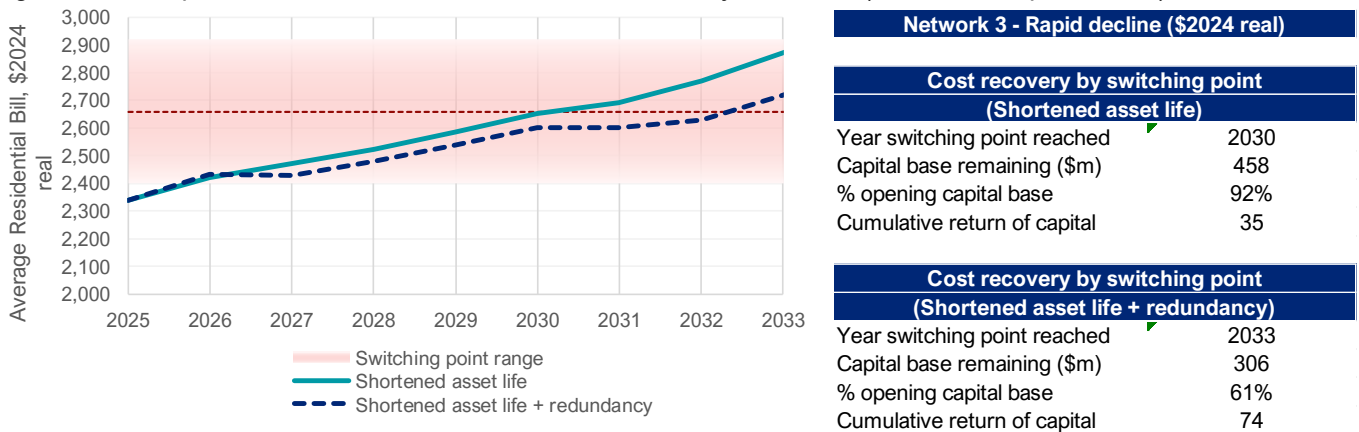
Source: CEPA.

The figures below summarise results from Network 3, under Scenario 3 (shortened asset life) and this Scenario 4 (shortened asset life + capital redundancy).

By making some assets redundant, Network 3 can maintain residential bills below the threshold for a slightly longer period: up to 2033, instead of 2030 with shorter asset lives alone (Figure 2.7). This allows it to recover an additional ~\$87m in return of and on capital before the assumed switching point is reached (Figure 2.8). However, under both approaches the illustrative network does not recover its entire efficient capital base before the switching point.

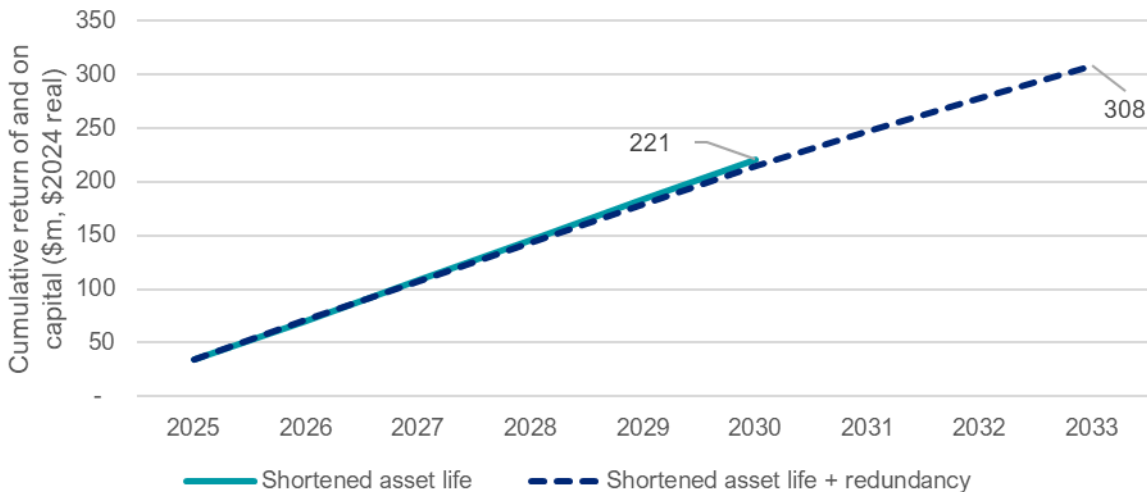
A comparison based on the cumulative return of and on capital up to the switching point is not perfect, because in both cases some revenue recovery could still be expected after retail bills rise above the assumed threshold (not all customers will disconnect at that point). However, it provides an indication of the capital base that could be recovered under more 'secure' conditions.

Figure 2.7: Comparison of shortened asset life and redundancy scenarios (Network 3, rapid decline)



Source: CEPA. Note Y-axis starts at \$2,000.

Figure 2.8: Cumulative return of and on capital, with and without redundancy (Network 3, rapid decline)



Source: CEPA.

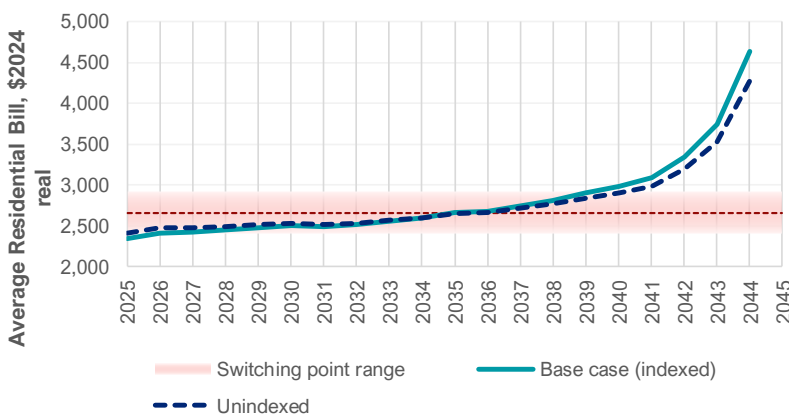
The magnitude of the impact of applying redundancy alongside asset life shortening partly depends on the modelling assumptions applied. For example, it is worth noting that the constant opex assumption is one factor that limits the extent to which bringing forward depreciation (relative to the base case) and/or applying capital redundancy flatten future bill increases in the model.

## 2.6. SCENARIO 5: CAPITAL BASE INDEXATION

Under the current regulatory framework, the capital base is indexed annually in line with inflation and service providers receive a real rate of return on the capital base. Alternatively, service providers can be remunerated for inflation by applying a nominal rate of return to an unindexed capital base. Compared to an indexed capital base approach, an unindexed capital base produces a more front-loaded profile of capital cost recovery.

Figure 2.9 below illustrates the effect of moving from an indexed to an unindexed capital base, all else equal, assuming that the switch occurs at the start of 2025. This scenario starts from the base case (Scenario 1) – i.e., assumes that shorter asset lives are applied to a proportion of the capital base at the start of the first access period. The results reflect illustrative Network 1, under the rapid decline scenario.

Figure 2.9: Comparison of base case and unindexed capital base scenarios (Network 1, rapid decline)



### Network 1 - Rapid decline (\$2024 real)

#### Cost recovery by switching point (Base case - Indexed)

Year switching point reached	2036
Capital base remaining (\$m)	339
% opening capital base	68%
Cumulative return of capital	135

#### Cost recovery by switching point (Unindexed)

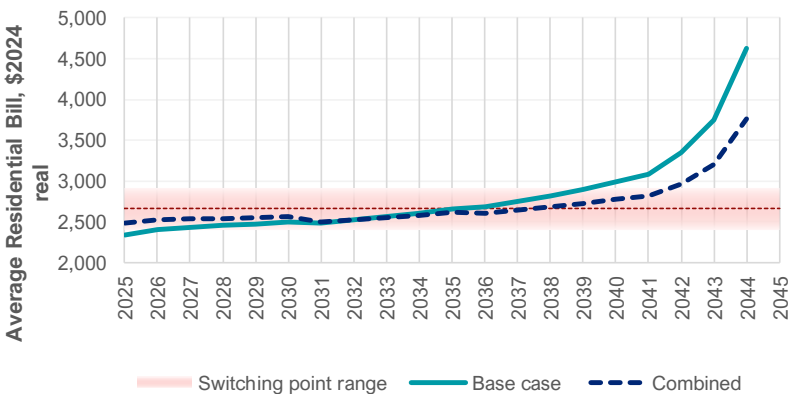
Year switching point reached	2036
Capital base remaining (\$m)	260
% opening capital base	53%
Cumulative return of capital	228

Source: CEPA. Note Y-axis starts at \$2,000.

## 2.7. SCENARIO 6: COMBINATION

An unindexed capital base could be combined with other regulatory levers. As in illustration of the combined impact, Figure 2.10 below combines asset life shortening (per the base case scenario), an unindexed capital base, and sum-of-digits depreciation. This illustrates that a combination of regulatory levers can in principle be applied to achieve targeted pricing and cost recovery outcomes.

Figure 2.10: Cumulative impact on base case - unindexed capital base and reprofiled depreciation



### Network 1 - Rapid decline (\$2024 real)

#### Cost recovery by switching point (Base case)

Year switching point reached	2036
Capital base remaining (\$m)	339
% opening capital base	68%
Cumulative return of capital	135

#### Cost recovery by switching point (Combined)

Year switching point reached	2038
Capital base remaining (\$m)	174
% opening capital base	37%
Cumulative return of capital	324

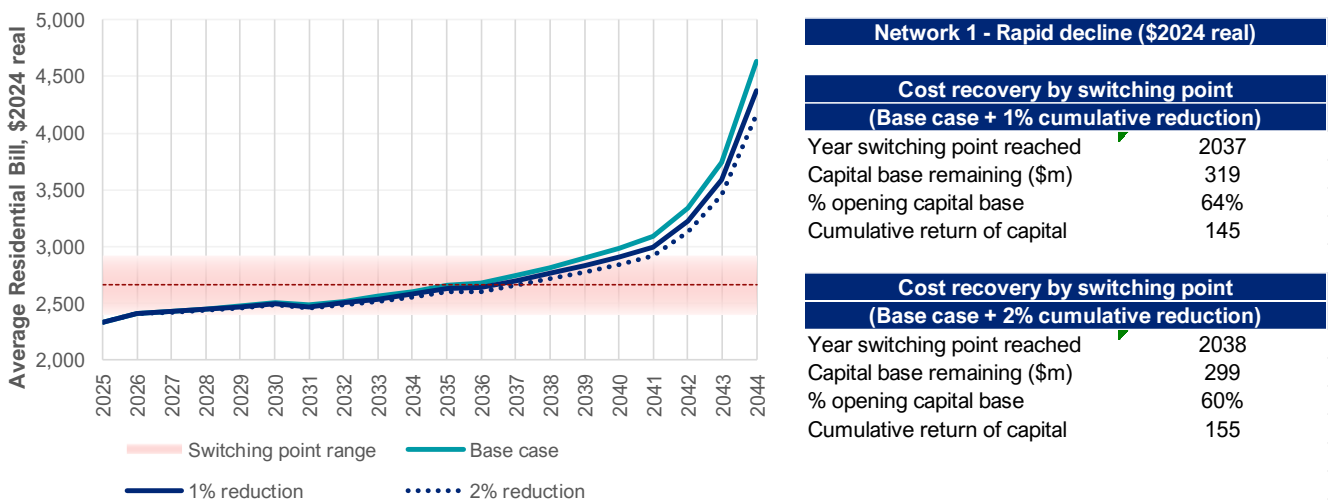
Source: CEPA.

## 2.8. SCENARIO 7: CAPEX AND OPEX CRITERIA

The NGR set out criteria to guide the AER’s assessment of efficient capex and opex. The Commission is contemplating changes to these criteria that may have the effect of more tightly controlling allowed expenditure. To illustrate the potential impact, this scenario assumes that relative to the base case, a cumulative 1-2% per annum reduction is applied to forecast capex and opex.

The figure below (Network 1, rapid decline scenario) illustrates that the cumulative impact reduces consumer bills over time – for example, by ~3% and ~5% by 2040 in total, relative to the base case scenario. The relatively modest impacts reflects that network charges are just one component of consumer bills, and that the impact takes time to build. The cumulative impacts on network charges alone are, by 2040, -7% and -13% respectively.

Figure 2.11: Illustrative impact of stricter opex and capex criteria (Network 1, rapid decline)



Source: CEPA.

## 2.9. SCENARIO 8: REVENUE CAP

The final scenario we have explored contemplates a change to the form of control. Some service providers are currently regulated under a hybrid price cap. Under this approach, the service provider is exposed to demand forecast errors within a band of +/- 5%, but share the impact of variations outside of this range with consumers. Alternatively, under a revenue cap, a service provider’s allowed revenues would be adjusted annual to fully offset the impact of demand variations (in net present value terms).

This scenario compares the hybrid price cap and revenue cap approaches, for Network 1 under the rapid decline scenario, starting from the base case. The scenario assumes that in the first AA period (2026-30), outturn demand is 4% lower than forecast in each year.

Under the hybrid price cap, Network 1 simply recovers less than its regulatory allowance (MAR) in those years. In the revenue cap variant, the negative demand variance leads to an upwards adjustment to MAR in the following year. The value of the adjustment is the amount of under-recovery (due to the demand variation), plus the allowed return on capital for that year. This makes the impact of demand variances are neutral in net present value terms.

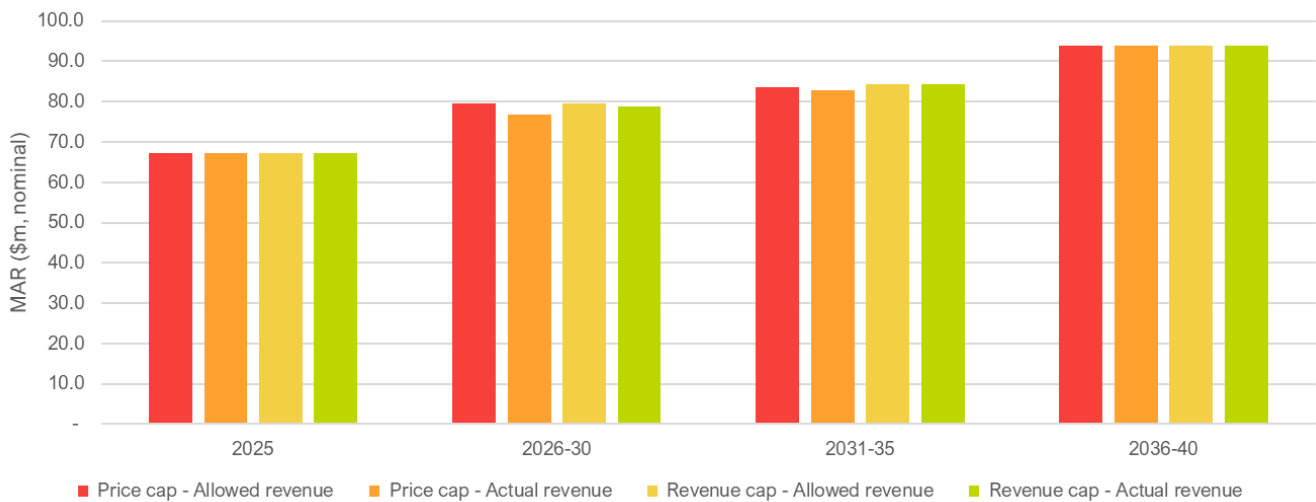
Average allowed and recovered MAR for both cases are shown in the table and figure below, for each AA period.

Table 2.5: Allowed and recovered MAR (\$'m, nominal) – Network 1 (rapid decline)

	Price cap - Allowed revenue	Price cap - Actual revenue	Revenue cap - Allowed revenue	Revenue cap - Actual revenue
<b>2025</b>	67.3	67.3	67.3	67.3
<b>2026-30</b>	79.5	76.9	79.5	78.9
<b>2031-35</b>	83.5	82.9	84.2	84.3
<b>2036-40</b>	93.9	93.9	93.9	93.9

Source: CEPA.

Figure 2.12: Allowed and recovered MAR (\$'m, nominal) – Network 1 (rapid decline)



Source: CEPA.

The scenario has also considered the impact on our residential bill switching point. We do not present the results from this scenario graphically, as the impact on residential bills in this case is immaterial. However, the revenue cap scenario (with a negative demand variance), network charges are *slightly* higher in the second AA than they otherwise would be. This may be financially beneficial to service providers if they can recover the upwards adjustment. However, this may be less likely to occur where demand is falling over time (i.e., demand true-ups could lead to residential bills crossing into the switching point sooner). This indicates that under a price cap, there may be a higher risk that service providers do not recover their efficient costs – but also a risk that they ‘over recover’ where forecasts are lower than outturn.

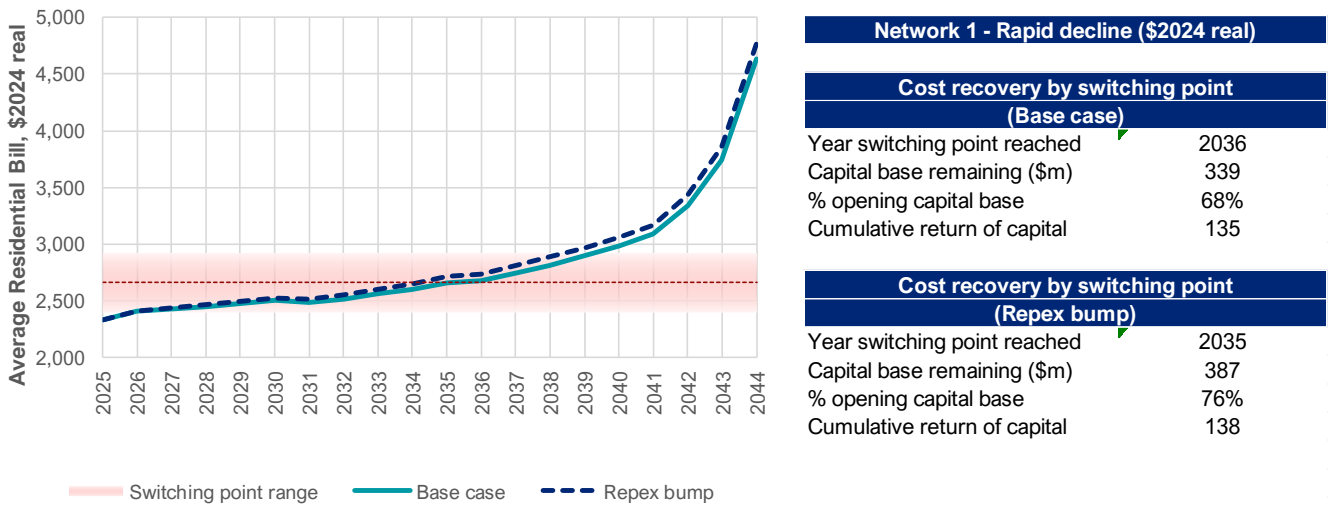
This simple scenario has not examined other potential implications of switching from a hybrid price cap to a revenue cap. For example, there may be changes in forecasting incentives, that could impact the magnitude of forecasting errors in each case.

## 2.10. REPEX SENSITIVITY

As outlined in Section 1.4.3, a flat repex assumption of 1.0% of the opening capital base may not be representative, particularly where a service provider is undertaking a major mains replacement cycle. We have tested the impact of a sensitivity, where repex is uplifted by an additional 1.5% over the first two AAs (2026-30, 2031-35).

The results below show the impact on illustrative Network 1 under the rapid decline demand case, starting from the base case scenario. The base case scenario assumes that a certain proportion of the capital base is depreciated over a shorter asset life. The same proportion is applied in the repex sensitivity, and so the results show the impact of changing the repex assumption in isolation.

Figure 2.13: Impact of temporary repex bump on base case (Network 1, rapid decline)



Source: CEPA.

In this particular sensitivity, the repex uplift increases the average residential bill, bringing forward by one year the date when the assumed switching point is reached. This results in a larger proportion of the capital base unrecovered at that time (noting that although the cumulative return of capital is higher in the repex uplift scenario, capex is also higher). Although higher repex impacts the level of cost recovery prior to the switching point, the level of materiality suggests that the scenarios *without* this sensitivity provide a reasonable representation of possible future outcomes. However, the impact of a more intensive repex program on real-world service providers and their customers will depend on their other characteristics.

### 2.11. IMPACT OF CUSTOMER COMPOSITION

As noted in Section 1.4.2, we have made assumptions regarding the starting percentage of total demand (in 2024) that is attributable to residential, commercial and industrial customers.

If we vary this assumption, then forecast demand will change. For example, under the gradual decline scenario, the higher the assumed starting percentage of industrial load, the more slowly demand will decline to 2050. This is because in the gradual decline scenario, we assume a slower year-on-year demand reduction for industrial customers, relative to residential / commercial customers. This means that, all else equal, the higher the starting proportion of industrial demand, the higher total demand will remain over time.

The impact of this on residential distribution network charge and bill levels depends on how costs are assumed to be shared between customer groups. If the relative proportions of residential, commercial and industrial customers changes, then the share of MAR that is allocated to each group should, in principle, also change. This re-allocation will determine the net impact of varying the customer composition assumption.



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