HOUSTONKEMP
Economists

Forecast methodology for meter stock and operating expenditure

A report for Ausgrid, Endeavour Energy, Essential Energy and Evoenergy

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Disclaimer

Contents

Figures

Tables

1. Introduction

Type five and six electricity meters (legacy meters) in New South Wales and the Australian Capital Territory are being replaced by smart meters that have a remote reading capability. Although electricity distribution service providers (DNSPs) have no control over the pace of this transition, they remain responsible for reading a declining stock of legacy meters.

Ausgrid, Endeavour Energy, Essential Energy and Evoenergy have asked us to develop a methodology by which to forecast the rate at which legacy meters will be replaced by smart meters during the regulatory control period commencing on 1 July 2024, and then to estimate the resulting effect on the operating cost of reading those meters.

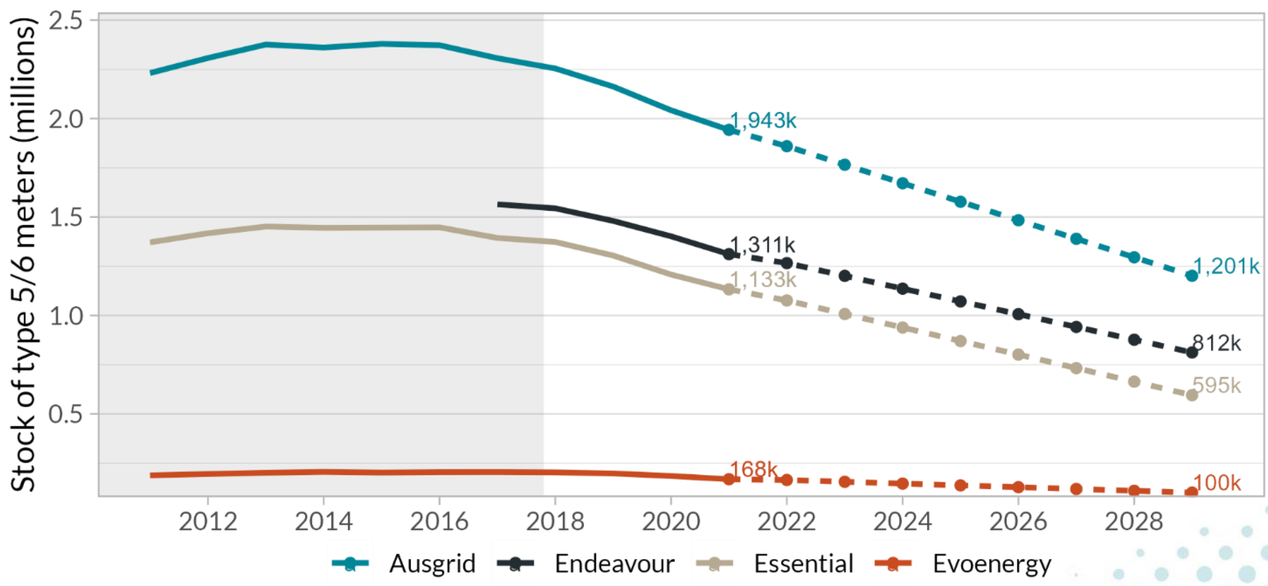
We undertook detailed discussions with each DNSP to understand the drivers of meter replacement and the drivers of the cost of meter reading. A key theme of these discussions was the geographic trends in meter replacements by responsible third parties, and how these trends are likely to exacerbate the inherently different cost of manually reading meters in different geographic areas.

We therefore focused our methodology on exploring geospatial trends in legacy meter replacements and the operating cost of reading those meters. This involved an extensive data gathering task in which DNSPs provided:

- latitude and longitude or postcode data for all historical meter replacements and their remaining stock of legacy meters; and
- various other data related, or that we cross-referenced, to replaced meters.

We present our forecast of the total stock of legacy meters for each DNSP in Figure 1.1.

Figure 1.1: Forecast of total stock of legacy meters by DNSP



Source: HoustonKemp analysis. Note: Sufficient data were not available for Endeavour before FY17.

In table 1.1 we present our annual forecast of meter replacements for each DNSP, broken down by geographic areas that are consistent with the Australian Bureau of Statistics' remoteness areas index.[1]

Table 1.1: Forecast of legacy meter replacements by DNSP and remoteness area

Remoteness area	Ausgrid	Endeavour	Essential	Evoenergy
Major Cities of Australia	-80,237***	-48,970**	-3,463**	-8,445*
Inner Regional Australia	-13,274***	-14,507**	-40,575**	-54
Outer Regional Australia	-513**	-1,350**	-22,850**	-626*
Remote Australia	NA	NA	-1,586**	NA
Very Remote Australia	NA	NA	-246**	NA
Total churn	**-94,024**	**-64,827**	**-68,721**	**-9,125**

Source: HoustonKemp analysis.
*Note: '***' significant at the 0.1 per level, '**' significant at the 1 per cent level, '*' significant at the 5 per cent level.*

We conclude from our extensive evaluation of alternative models and estimation techniques that there is no evidence of a statistically significant relationship between the stock of legacy meters and the cost of scheduled meter reading.

Importantly, this does not mean that meter reading costs are unrelated to the stock of meters. Rather, it suggests that relatively low levels of geographically dispersed meter replacements may not significantly decrease meter reading costs, because it results in relatively limited scope to optimise meter reading routes. That said, as the stock of meters falls in specific geographic areas, we expect that meter reading costs will fall in line with the reduction in the number and length of meter reading routes.

The remainder of our report is structured as follows:

- in section 2 we set out the context to this project, including the findings of our engagement with the DNSPs;
- in section 3 we describe our proposed methodology for forecasting the rate of legacy meter replacements over the regulatory control period by reference to historical meter replacement data;
- in section 4 we explain our proposed methodology for forecasting the effect of meter replacements on the operating cost of reading legacy meters; and
- in section 5 we describe how DNSPs can combine the meter reading cost forecast with their other metering operating costs, to estimate a productivity factor for application in the Australian Energy Regulatory Authority's (AER's) rate of change formula.

[1] See, Australian Bureau of Statistics, the Australian Statistical Geography Standard Remoteness Areas Structure, available at: https://www.abs.gov.au/websitedbs/d3310114.nsf/home/remoteness+structure.

2. Background

In this section, we describe the context in which we developed our approach to forecasting the stock of legacy meters and estimating the relationship between meter stock and the cost of reading meters. In particular, we:

- summarise regulatory developments that are relevant to the transition to advanced meters;
- explain the different types of electricity meters;
- describe the drivers that lead to the replacement of legacy meters; and
- discuss how the economics of meter reading means that a small reduction in meter stock leads to a smaller relative reduction in meter reading cost.

2.1 Regulatory developments

Approximately ten years ago the Australian Energy Market Commission (AEMC) undertook a review of demand side participation in the national electricity market, reflecting that participants on both the supply and demand side of a market have a role to play in its efficient operation.

The purpose of this review was to identify opportunities for consumers to make more informed choices about how they use electricity and interact with the electricity system. Since metering technology is a key enabler of demand side participation, the AEMC identified that developing arrangements to facilitate the uptake of metering technology was a key next step.[2]

This next step manifested in a change to the National Electricity Rules (the rules) in 2015 – the competition in metering rule change – to facilitate the market-led deployment of advanced meters.[3]

This rule came into effect on 1 December 2017 and substantially changed the role of DNSPs in relation to electricity meters. Its effects included that:

- responsibility for meter replacements fell to third parties, rather than DNSPs;
- new or replacement meters must meet minimum requirements that, in effect, meant they must be advanced meters; and
- responsibility for reading and testing legacy meters remained with DNSPs.

It follows from these changes that DNSPs have very little control over the roll-out of smart meters, but remain responsible for the operating cost of manually reading a declining stock of legacy meters.

At the time of preparing this report, the AEMC is undertaking a review of the regulatory framework for metering services.

[2] AEMC, *Power of choice - giving consumers options in the way they use electricity, Directions Paper*, March 2012, p i.

[3] AEMC, *Rule Determination – National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, November 2015.

In its directions paper the AEMC explained that, at a minimum, the review needs to improve incentives for the timely and efficient replacement of legacy meters. It also observed that additional measures, beyond incentives, may be required, eg:[4]

- improving incentives to rolling out smart meters by removing inefficiencies in the installation processes, improving cost sharing, and aligning incentives
- requiring meters to be replaced once they have reached a certain age, for example 30 years, under an aged-replacement roll out
- setting targets for the roll out under which a retailer (or the responsible party) will be required to replace a certain percentage of their customers' meters with smart meters each year
- introducing a 'backstop' date or dates by which time all accumulation meters or manually read interval meters must be replaced, for example 90% of meters required to be smart meters by 2030.

2.2 Types of electricity meters

In this section we briefly summarise the characteristics of legacy meters – being accumulation and interval meters – and the advanced meters that must be installed for all new connections and meter replacement.

The key distinction between these metering technologies is that accumulation and interval meters have to be read in-person, whereas advanced meters have a remote-reading capability.

2.2.1 Accumulation meter – manual reading

Accumulation meters (or type 6 meters) measure the total level of electricity used by a customer, such that they cannot measure or provide information as to the timing of a customer's energy use. Customers with accumulation meters therefore typically face flat network tariffs, where the price they face does not vary across the day to reflect the changing cost of providing electricity network services.

Accumulation meters have no remote-reading capability and therefore have to be read manually, onsite. Due to their basic design and functional simplicity, they can often last many years beyond their standard economic life, which is typically in the order of 40 years.

The vast majority of electricity meters in New South Wales and the Australian Capital Territory are accumulation meters.

2.2.2 Interval meter– manual reading

In contrast to accumulation meters, interval meters (or type 5 meters) are electronic meters that record electricity use over half hour intervals. They therefore facilitate time-of-use prices and provide DNSPs with better visibility over how customers are using the network.

Like accumulation meters, the reading of interval meters is undertaken manually, onsite.

The roll-out of interval meters was interrupted by the requirement in the competition in metering rule change for all new and replacement meters to be advanced meters, which left relatively few interval meters in service.

2.2.3 Advanced meter (type 4) – remote reading

Unlike accumulation and interval meters, advanced meters (or type 4 meters) measure electricity use in near real time and are capable of two-way communication.

[4] AEMC, *Review of regulatory framework for meter replacements*, 16 September 2021, p ii.

This means that advanced meters need not be read on-site.

In addition to providing DNSPs with real-time data that assists DNSPs operationally – eg, identifying network outages in real time – advanced meters facilitate the provision of a range of other services such as remote access to appliances and can enable customers to monitor and adjust their electricity use in response to price signals.

2.3 Drivers of meter replacements

There are two broad drivers of legacy meter replacements, being:

- a request by or through an electricity retailer (a retailer request); or
- some form of meter failure.

2.3.1 Retailer requests

We understand from DNSPs that most historical meter replacements arose from a request from the relevant customer's electricity retailer. However, DNSPs have almost no visibility as to the reasons underpinning such retailer requests.

A consistent theme across DNSPs was that the biggest driver of retailer requests – and meter replacements more generally – was the installation of solar photovoltaic (PV) systems by customers, which require an advanced meter.

There are also a wide range of other circumstances that could lead to a retailer request for a meter replacement, eg:

- a customer upgrades to a three phase connection, eg, to enable the fast-charging of an electric vehicle (EV);
- building works that require the re-location of a customer's existing, legacy meter;
- a customer with an accumulation meter requests assignment to a time-variant electricity tariff, eg, a demand tariff; and
- a retailer-led initiative to replace legacy meters.

All DNSPs highlighted that retailers face weak incentives to initiate meter replacements on their own volition, ie, absent a request that originated with the customer. For instance, few DNSPs were aware of a retailer-led initiative to replace legacy meters on their network.

The weak incentives faced by retailers are likely to be a key reason why the rate of meter replacements to date has been much lower than had previously been expected.

2.3.2 Meter failures or faults

There are two categories of meter failure that can lead to a meter replacement, ie, an individual meter failure or a meter family failure.

An individual meter failure can arise from:

- building works or storm damaging the meter and leading to a power outage; or
- when a person reading the meter detects that it has stopped working.

The second category of meter failure is a 'family failure', which occurs when a particular brand and/or vintage of meter is identified as breaching accuracy standards. Family failures are identified through obligatory periodic testing of meter accuracy by DNSPs.

The historical rate of family failures has generally been low but, depending on the prevalence of the affected meters, they can lead to lumpy, material replacement requirements.

AEMO exemptions

A metering co-ordinator must repair or replace a failed meter within 15 days of notification from a DNSP.

However, many DNSPs identified that it is common for metering co-ordinators to request and receive an exemption from the Australian Energy Market Operator (AEMO) from this requirement. There is a particularly strong incentive for metering co-ordinators to seek exemptions in response to a family failure because of the costs involved in replacing meters that are likely to be spread over a broad geographic area.

The prevalence of exemptions often means that meter faults do not translate into meter replacements. For instance, Endeavour Energy has approximately 17,000 meters that were identified as family failures – dating as far back as 2017 – that are the subject of an exemption and have not yet been replaced.

Many DNSPs observed that the third parties responsible for meter replacements focus their efforts on meters that can be replaced at low cost, eg, typically meters located close to available labour or where meters that required replacement are co-located. This reflects the weak incentives for these third parties to replace meters and the availability of exemptions, and gives rise to the likelihood of geographic trends in meter replacements.

2.4 Economics of meter reading

Legacy meters must be read in-person on a customer's premises to determine their energy use since the last reading was taken. These reads are typically undertaken four times a year.

This process is performed by assigning each meter to a route, which is driven or walked (or a combination of the two) depending on the geographic features of the area and the density of meters in that location. Driven routes are typically more expensive to complete.

These routes are periodically optimised as the stock and density of legacy meters reduces through time. However, the scattered replacement of meters to date has substantially limited the scope for route optimisation.

It follows that as meters are replaced, the routes remain substantially the same, such that meter readers travel past the location of meters that have been replaced. This limits the impact of meter replacements on meter reading costs, since the only time saving relates to avoiding the need to access and read a meter on a site that they are often still travelling past.

In remote areas where there is much lower meter density, a meter replacement can lead to an incrementally larger saving in travel time, since it may enable a meter reader to avoid the need to travel down a particular road or access a challenging site.

On the other hand, remote areas have a much higher proportion of driven routes, which are typically more costly to operate. Some rural areas also require that at least one person is retained, irrespective of the number of meters, because of the significant distance to a nearby town, which limits the opportunity for meter reading costs to fall as meters are replaced. For instance, Essential Energy noted that it has approximately 85 locations that require the retention of at least one person to read meters because the nearest town is upwards of 100 kilometres away.

Similarly, densely populated urban areas come with their own challenges, such as finding parking and accessing locked basements or multiple floors to read meters in older apartment buildings. For example, Ausgrid noted that the availability of parking is a key driver of the time taken to complete some driven routes.

The result of these dynamics is that a decline in the number of meters to be read leads to a relatively smaller decline in the cost of reading meters. In other words, there is economies of scale in meter reading.

Although economies of scale is typically referred to in the context of an increase in production that leads to lower average costs, it also means that a decrease in production – in this case, meters read – can lead to *higher* average costs.

Our discussions with DNSPs also highlighted that the scalability of meter reading costs is constrained in different forces across their networks, depending primarily on the proximity to labour and density of meters. It follows that sensitivity of meter reading cost to changes in meter stock is likely to vary across the geographic areas covered by each DNSP's network.

It is also relevant to note that DNSPs had varying perspectives on the prospect of achieving economies of scope by reading electricity, gas and water meters at the same time. While meters on some DNSP networks are read at the same time as other utilities, other DNSPs highlighted that this can cause financial challenges for customers since they receive multiple utility bills at the same time. We understand that it is for this reason that other utilities have in some cases declined to combine meter reading activities with a DNSP.

2.4.1 Labour constraints

DNSPs noted that the rise in average cost associated with a declining stock of electricity meters has been exacerbated by challenges in the labour market, many of which have risen to prominence in the last few years.

Meter reading is undertaken by a highly mobile workforce that receives close to minimum wage, with the consequence that labour retention and the cost of training new meter readers is an enduring challenge.

We understand that these challenges have been exacerbated by the COVID-19 pandemic with the challenges presented by a series of lock-downs. By way of example, challenges in securing and retaining labour have arisen from perceptions that the task of meter reading has become more unpleasant due to:

- consecutive years of unusually high rainfall associated with the La Nina climate pattern;
- increases in abuse targeted at meter readers, driven by the prevalence of people working from home and observing, for the first time, a meter reader accessing their property; and
- an increase in the number of properties with dogs, following an increase in pet ownership during multiple lock-downs and people working from home.

The recent floods in New South Wales have also significantly tightened the labour market in affected regions, due to increased demand from labour hire companies associated with repair and clean up works.

3. Forecast meter replacements

In this section, we describe the methodology we applied to forecast the stock of legacy meters over the regulatory control period from 1 July 2024 to 30 June 2029, based on empirical data provided by the DNSPs.

3.1 Overarching framework for forecasting meter replacements

Our approach to forecasting meter replacements involved an extensive exercise accumulating data from each of the DNSPs involved in this study, combined with an exhaustive analytical exercise.

3.1.1 Combined data across DNSPs

The joint nature of this project presented a unique opportunity to improve our insights by combining data across four DNSPs, such that our assessment is based on meter data across the entirety of New South Wales and the Australian Capital Territory.

The appropriateness of this approach reflects that the rate of meter replacements is beyond the control of DNSPs and that the historical key driver of meter replacement – the installation of solar PV systems – is driven by a range of factors, many of which are unrelated to network characteristics, eg, the attraction of contributing to a clean energy system.

3.1.2 Geospatial assessment

Our discussions with DNSPs indicated that there were geographic trends in the replacement of legacy meters, reflecting the limited incentives for the responsible third parties to undertake replacements and the ability to acquire replacements exemptions.

We therefore founded our approach on a geospatial assessment of how meter replacements, and the role of the underlying drivers, varied across different areas of New South Wales and the Australian Capital Territory.

In practice, this was undertaken by sourcing from each DNSP a geospatial identifier – either latitude and longitude or the applicable post code – for its historical meter replacements.

3.1.3 Platform from which to assess future change

Important context to our assessment is the AEMC's ongoing 'review of the regulatory framework for metering services', which is ultimately directed at expediting the replacement of legacy meters. The outcome of this review has the potential to significantly influence the pace and optimisation of meter replacements over the next regulatory control period.

Given prevailing uncertainty as to the outcome of the AEMC's review, we have derived our forecast by reference to historical trends in meter replacements and disaggregated our forecast by driver.

We have also disaggregated the forecast of meter replacements by reference to each overarching driver of churn, eg:

- 'solar-driven' replacements, ie, those necessitated by the installation of a solar PV system;
- other customer or retailer initiated replacements;
- reactive meter failures, ie, in response to an observed meter failure; and
- meter family failures (or proactive replacements), eg, when a cohort of meters breaches accuracy standards.

This establishes a clearly defined, empirical-based platform from which to assess the incremental effect of the future outcome of the AEMC's review.

For instance, if the AEMC implements its contemplated requirement that meters must be replaced at a certain age,[5] DNSPs need only assess the incremental effect of this requirement on the historical-based, failure-driven meter replacement forecast.

3.2 Data

We requested from DNSPs various historical data over the period commencing in 2011, including:

- the date of historical meter replacements;
- a geospatial identifier for each meter replacement, ie, latitude and longitude or a postcode;
- whether each meter replacement was due to a family failure, reactive failure or was initiated by a retailer;
- future information relevant to each driver, eg, scheduled tests, as relevant to family failures.
- information that could be used to inform whether it was reasonable to assume that a retailer-initiated replacement was caused by a solar PV installation.

A key theme arising from our data gathering process was that DNSPs have put significant effort into maintaining meter replacement data following the commencement of power of choice reforms at the end of 2017.

There was significant variation in each DNSPs approach to recording meter replacement data in the earlier years going back to 2011.

For each DNSP we cross-referenced and reconciled meter data from multiple sources. By way of example, to inform whether a replacement was driven by a reactive or pro-active failure, in some cases we had to cross-reference meter failure notices against historical replacement records, while accounting for whether:

- there was a record of an AEMO exemption for the meter failure notice (MFNs), since not all MFNs result in a meter replacement; and
- a meter replacement was due to a MFN in a previous year, but for which an AEMO exemption had previously been acquired.

The differences in records across DNSPs – as well as changes in their approach over time – meant that the compilation of a standardised data set in some cases came at the expense of excluding some data. In our opinion any limitations arising from such exclusions were far outweighed by the additional explanatory power arising from the combination of data across four DNSPs.

3.3 Analysis

In this section we describe the approach we applied to develop a geospatial forecast of meter replacements, by driver for each DNSP over the upcoming regulatory control period.

3.3.1 Geographic identifier

Each DNSP provided us with a geospatial identifier for historical meter replacements in the form of longitude and latitude or the relevant postcode.

[5] AEMC, *Review of regulatory framework for meter replacements*, 16 September 2021, p ii.

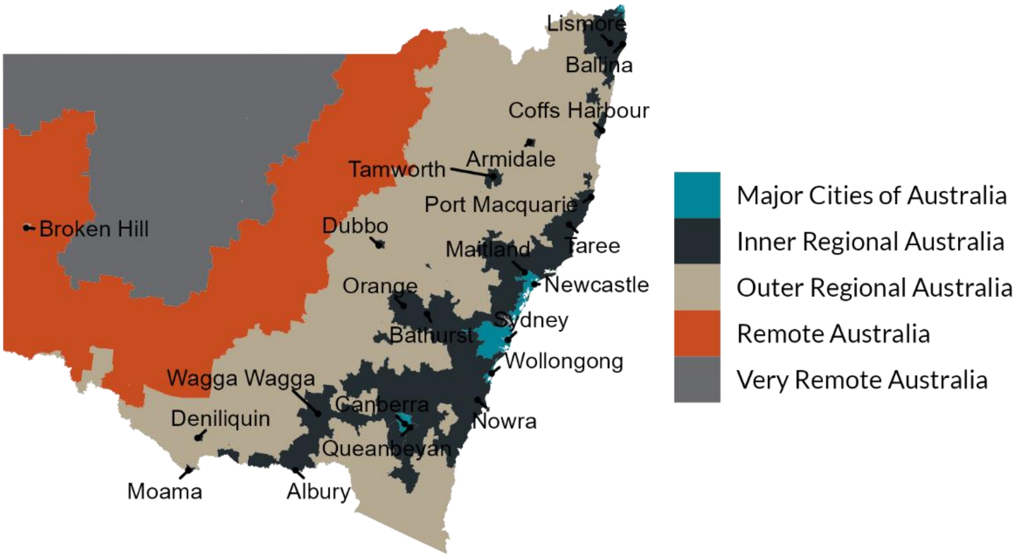
We used the remoteness areas index prepared by the Australian Bureau of Statistics (ABS) to classify each meter/replacement.[6] The ABS's remoteness areas index is well-suited to this analysis, since it classifies the area covered by Australia based on a measure of relative access to services.[7]

Specifically, it classifies Australia into:

- major cities of Australia;
- inner regional Australia;
- outer regional Australia;
- remote Australia; and
- very remote Australia.

We illustrate the classification of New South Wales and the Australian Capital Territory into these five definitions in Figure 3.1.

Figure 3.1: New South Wales and the Australian Capital Territory by remoteness area

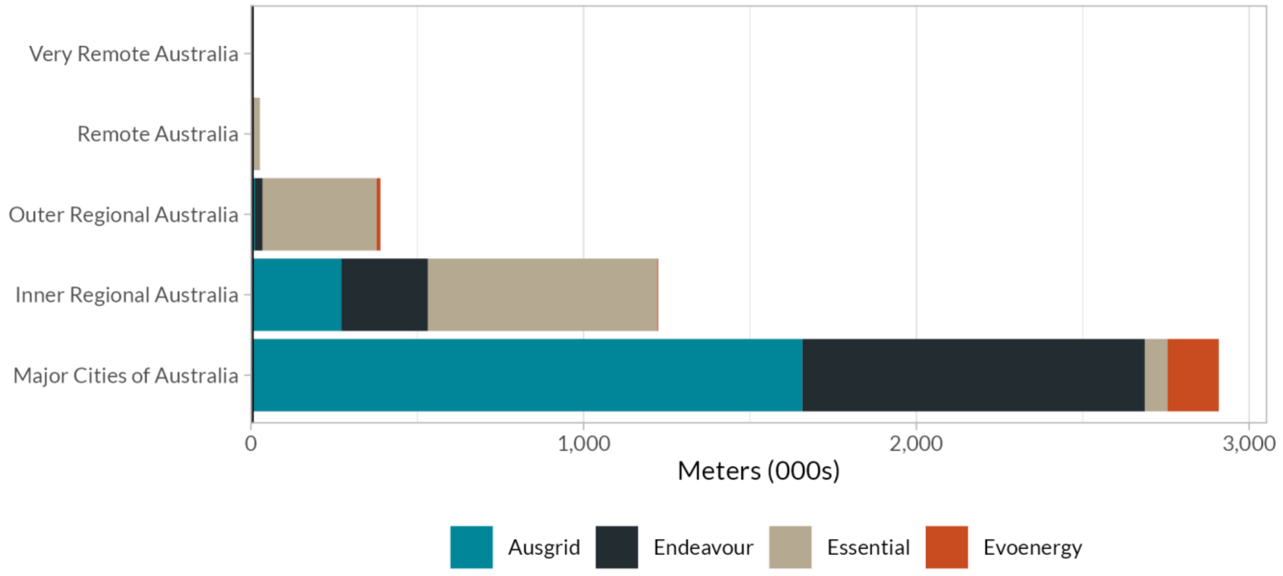


We present the current stock of legacy meters by remoteness areas and DNSP in Figure 3.2. The majority of Ausgrid, Endeavour Energy and Evoenergy's legacy meters are in major cities, whereas inner regional Australia had the highest meter stock for Essential Energy.

[6] A small number of meters are in postcodes that cross into two different remoteness area classes. In these cases, we allocated meters into the remoteness area containing the largest proportion by area of the postcode. A very small number of meters could not be matched to a remoteness area. These meters were allocated to the largest remoteness area (by meter population) for the relevant DNSP.

[7] See, Australian Bureau of Statistics, the Australian Statistical Geography Standard Remoteness Areas Structure, available at: https://www.abs.gov.au/websitedbs/d3310114.nsf/home/remoteness+structure.

Figure 3.2: Stock of legacy meters by DNSP and remoteness area, FY21



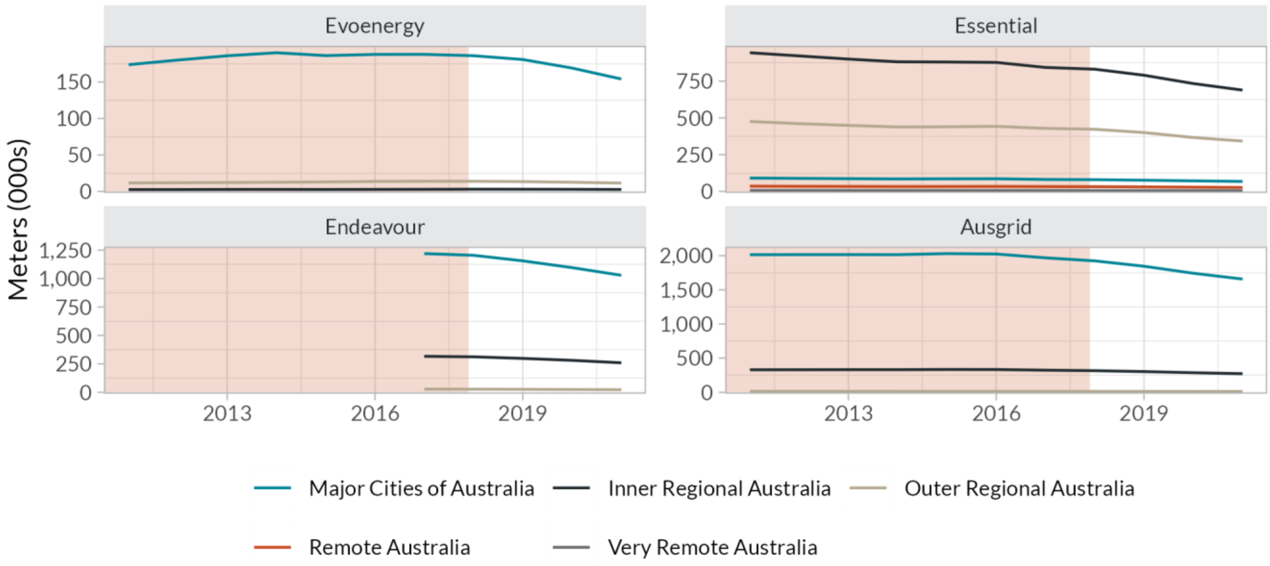
Source: HoustonKemp analysis of data provided by DNSPs; DNSP RIN responses. Note: Meter stock is adjusted to ensure that total stock aligns between the RINs and meter datasets.

3.3.2 Forecasting meter stock

We present in figure 3.3 each DNSP's stock of legacy meters by remoteness areas. We observed that across the four DNSPs, the population of legacy meters fell in all remoteness areas, although at different rates.

As expected, there is a clear structural break in the pace of legacy meter replacements upon the commencement of the power of choice reforms at the end of 2017. The presence of a structural break for each DNSP in each remoteness area at the commencement of the power of choice reforms is confirmed by a Chow test. The application of a Chow test produced a *p*-value that was consistently less than 0.05, which means that we can reject the null hypothesis that there is no structural break and proceed on the basis that the data do contain a structural breakpoint.

Figure 3.3: Stock of legacy meters by DNSP and remoteness area over time



In addition to the limited period of time that has transpired since the power of choice reforms, the most recent years are likely to be affected by the COVID-19 pandemic. The combination of these factors is a significant challenge for forecasting meter stock.

The functional form that best reflects our conceptual definition of meter stock is:

$$\begin{aligned}Stock_{RA,DNSP,t} = Stock_{RA,DNSP,t-1} &- FaultDrivenReplacements_{RA,DNSP,t} - MFFReplacements_{RA,DNSP,t} \\ &- SolarDrivenReplacements_{RA,DNSP,t} - OtherReplacements_{RA,DNSP,t} \\ &+ LegacyAdditions_{RA,DNSP,t}\end{aligned}$$

The explanation of each of the components of this equation is set out in table 3.1 below.

Table 3.1: Variables in stock equation

Parameter	Explanation
$Stock_{RA,DNSP,t}$	• the number of legacy meters held by *DNSP* in remoteness area *RA* in year *t*
$FaultDrivenReplacements_{RA,DNSP,t}$	• the number of legacy meters replaced due to faults by *DNSP* in remoteness area *RA* in year *t*
$MFFReplacements_{RA,DNSP,t}$	• the number of legacy meters replaced due to meter family failures by *DNSP* in remoteness area *RA* in year *t*
$SolarDrivenReplacements_{RA,DNSP,t}$	• the number of legacy meters replaced due to the installation of solar PV by a customer of a *DNSP* in remoteness area *RA* in year *t*
$OtherReplacements_{RA,DNSP,t}$	• the number of legacy meters replaced due other retailer/consumer-led reasons for a *DNSP* in remoteness area *RA* in year *t*
$LegacyAdditions_{RA,DNSP,t}$	• the number of legacy meters added to the network by *DNSP* in remoteness area *RA* in year *t*.[8]

[8] Note that legacy additions become zero once like-for-like replacements of legacy meters ceased and will be zero for all future periods as all meters are replaced by advanced meters.

This functional form reflects that the stock of legacy meters at the end of one year is equal to the stock at the beginning of the year, less any removals, plus any additions.

Each of the replacement drivers in our conceptual definition of meter stock can in theory then be modelled separately, eg:[9]

$$FaultDrivenReplacements_{RA,DNSP,t} = \alpha_{RA,DNSP} + \beta_{RA,DNSP}\ t + \varepsilon_t;\ or$$

$$FaultDrivenReplacements_{RA,DNSP,t} = \alpha_{RA,DNSP} + \phi_{RA,DNSP} FaultDrivenReplacements_{RA,DNSP,t-1} + \varepsilon_t$$

Where:

- the first model is a simple linear model with a time trend; and
- the second model is an autoregressive model of replacements – ie, the replacements in one year depend on replacements in the previous year.

We also tested for similar models at lesser levels of granularity, eg:

$$\begin{aligned} Stock_{RA,DNSP,t} = {} & Stock_{RA,DNSP,t-1} - Fault/MFFDrivenReplacements_{RA,DNSP,t} \\ & - Solar/OtherReplacements_{RA,DNSP,t} + LegacyAdditions_{RA,DNSP,t} \end{aligned}$$

This model aggregates replacements to the level of 'reactive' replacements (faults and MFFs) and 'proactive' replacements (solar and other).

We applied similar structural breaks for the power of choice commencement to these models.

We concluded from this analysis that, despite its sound conceptual basis, this functional form is too granular a specification in light of the data limitations that we discuss in section 3.2. Given the more fulsome and consistent data available after power of choice, we expect that this functional form could become more appropriate in future applications.

As a result of this practical reality, we separately forecast meter stock and then meter replacements by driver. We explain our meter stock model below and describe our approach to forecasting meter replacements by driver in section 3.3.3.

Trend model

In light of the structural break in meter replacements upon the commencement of the power of choice reforms, pre-power of choice information provided little explanatory power for expected changed in meter stock going forward. We found that the best performing model of legacy meter stock was based on a linear time trend, ie:[10]

$$Stock_{RA,DNSP,t} = \alpha_{RA,DNSP} + t_{RA,DNSP}$$

A linear time trend would reflect circumstances in which labour constraints lead to a stable level of meter replacements each year. It also implies that the proportion of existing stock being replaced in each year is increasing through time.

Our analysis identified a statistically significant, linear time trend for each DNSP in each remoteness area. We present our results in Table 3.2.

[9] Similar conceptual equations would apply for the different drivers of stock churn.

[10] We also tested a range of other models, such as generalised additive models. However, in our opinion the simple linear models represent a balance between the simplicity of the model while still presenting significant explanatory power and an interpretable model. See: Wood, S N, *Fast stable restricted maximum likelihood and marginal likelihood estimation of semiparametric generalized linear models*, Journal of the Royal Statistical Society (B), 2011, 73(1), pp 3-36.

Table 3.2: Linear time trend model of meter stock

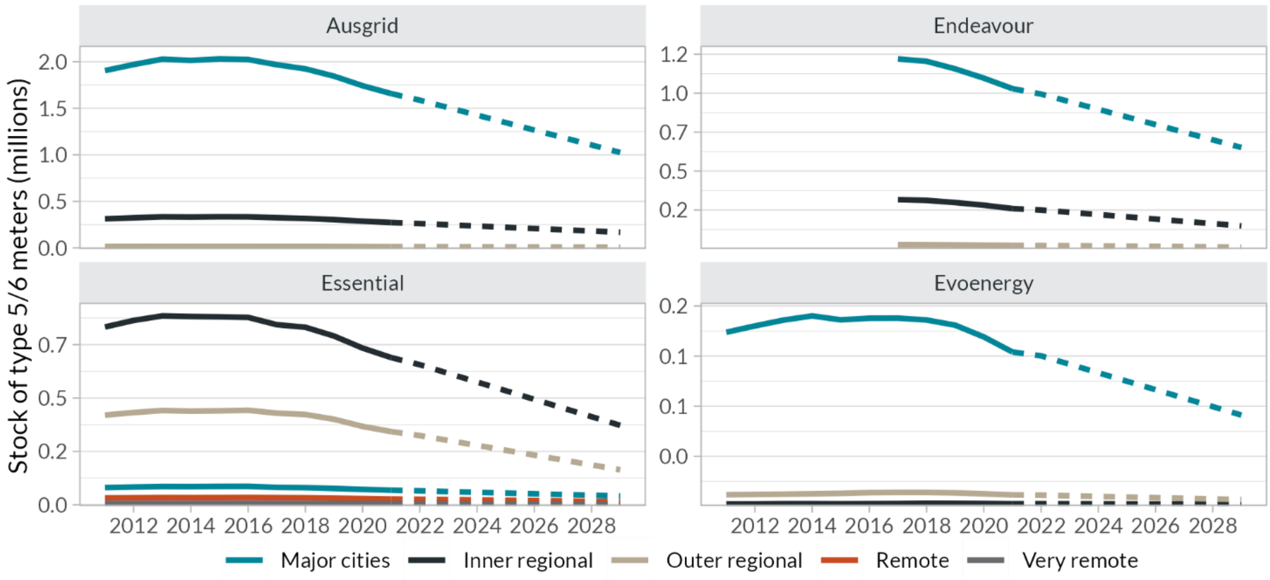
DNSP	Remoteness area	Intercept	Coefficient on time variable
Ausgrid	Inner Regional Australia	327,040***	-13,274***
Ausgrid	Major Cities of Australia	1,987,949***	-80,237***
Ausgrid	Outer Regional Australia	14,556***	-513**
Endeavour	Inner Regional Australia	322,407***	-14,507**
Endeavour	Major Cities of Australia	1,238,995***	-48,970**
Endeavour	Outer Regional Australia	28,469***	-1,350**
Essential	Inner Regional Australia	858,794***	-40,575**
Essential	Major Cities of Australia	82,618***	-3,463**
Essential	Outer Regional Australia	438,106***	-22,850**
Essential	Remote Australia	33,694***	-1,586**
Essential	Very Remote Australia	6,417***	-246**
Evoenergy	Inner Regional Australia	3,040***	-54
Evoenergy	Major Cities of Australia	192,461***	-8,445*
Evoenergy	Outer Regional Australia	14,361***	-626*

Source: HoustonKemp analysis.
*Note: '***' significant at the 0.1 per level, '**' significant at the 1 per cent level, '*' significant at the 5 per cent level.*

In proportional terms, the stock of meters in major cities fell slightly slower than in other areas. The exact drivers of these changes are not clear but could be related to the much higher absolute number of meters in major cities and any labour constraints could become magnified in those areas.

In figure 3.4 below we show the remoteness-level forecasts for each DNSP.

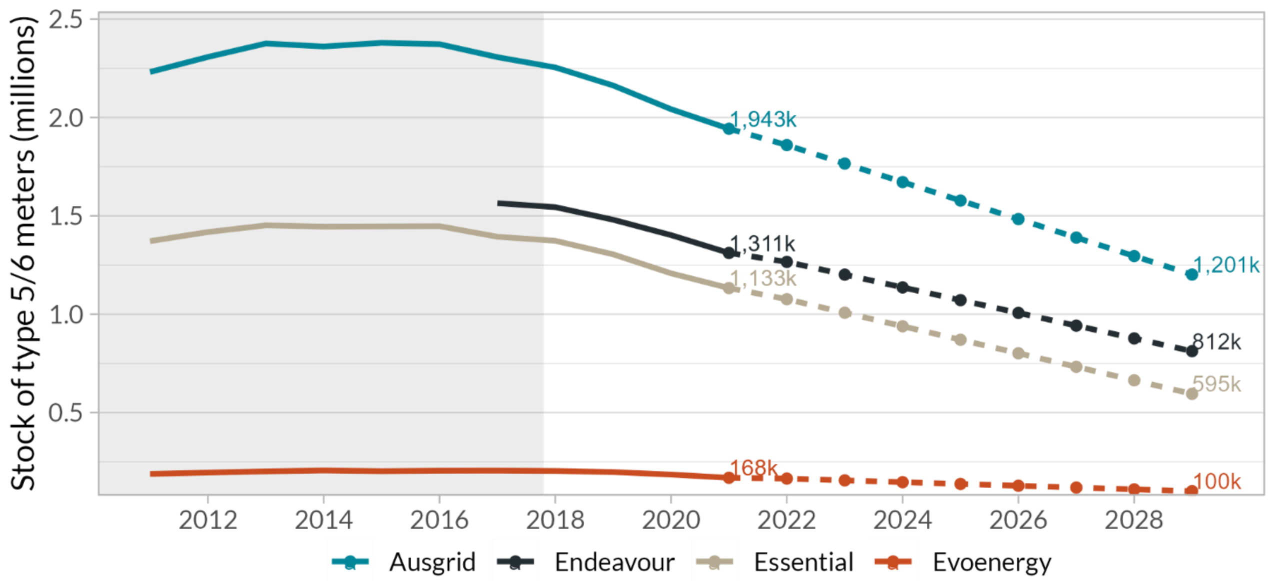
Figure 3.4: Forecast of legacy meter stock by DNSP and remoteness area



Source: HoustonKemp analysis. Note: Limited data was available for Endeavour Energy before FY17.

Figure 3.5 presents the total legacy meter stock forecast for each DNSP until the end of the next regulatory period, built up from the forecasts in figure 3.4 above.

Figure 3.5: Forecast of total legacy meter stock by DNSP



Source: HoustonKemp analysis. Note: Sufficient data were not available for Endeavour before FY17.

We present tabulated estimates of total meter stock in table 3.3.

Table 3.3: Forecast of legacy meter stock over time by DNSP

	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Ausgrid	1,942,512	1,859,426	1,765,402	1,671,378	1,577,355	1,483,331	1,389,307	1,295,284	1,201,259
Endeavour	1,311,084	1,265,735	1,200,906	1,136,080	1,071,252	1,006,424	941,598	876,770	811,943
Essential	1,132,683	1,076,027	1,007,307	938,585	869,865	801,143	732,424	663,703	594,982
Evoenergy	168,310	164,240	155,115	145,991	136,866	127,741	118,617	109,493	100,368

Note: FY22 values return to the modelled trend and therefore the churn between FY21 and FY22 differs to all other years.

In table 3.4 we present the level of meter replacements reflected in figure 3.5, broken down by remoteness area.

Table 3.4: Forecast of legacy meter replacements by DNSP and remoteness area

Remoteness area	Ausgrid	Endeavour	Essential	Evoenergy
Major Cities of Australia	-80,237***	-48,970**	-3,463**	-8,445*
Inner Regional Australia	-13,274***	-14,507**	-40,575**	-54
Outer Regional Australia	-513**	-1,350**	-22,850**	-626*
Remote Australia	NA	NA	-1,586**	NA
Very Remote Australia	NA	NA	-246**	NA
Total churn	**-94,024**	**-64,827**	**-68,721**	**-9,125**

Source: HoustonKemp analysis.
*Note: '***' significant at the 0.1 per cent level, '**' significant at the 1 per cent level, '*' significant at the 5 per cent level.*

3.3.3 Break-down of meter replacements by driver

In this section we describe our approach to disaggregating the level of meter replacements that is implicit in the stock forecast that we present in the previous section. We explain in section 3.3.2 that we undertake this process separately because an integrated stock/driver model requires a functional form that is too granular for the data limitations that we discuss in section 3.2.

We take slightly different approaches across DNSPs to ensure that we maximise the insights available from the data they each have available.

Further, the disaggregation of our stock forecast into four components – ie, solar-driven replacements, other retailer-initiated replacements, reactive failures and family failures – required an emphasis on years in which there was a more disaggregation of meter replacements.

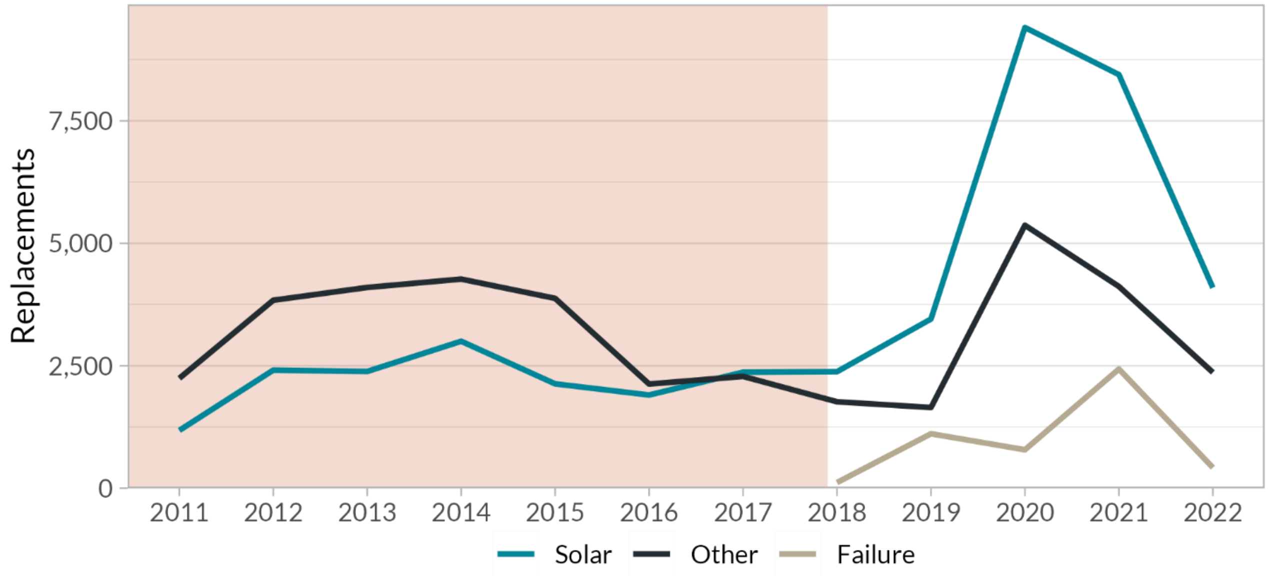
This led to a natural focus on the period after the power of choice reforms, when more fulsome data was generally available. It also ensures that we generally evaluate the role of these drivers over a period that is most relevant to the circumstances applying in future years.

Evoenergy

The most granular breakdown of historical meter replacements available for Evoenergy is in the period after the power of choice reforms, ie, 2018 onwards.

We present in figure 3.6 a breakdown of Evoenergy's historical meter replacements by solar-driven replacement, other retailer-initiated replacements, and total failure-driven replacements, where the latter is available from 2018 onwards.

Figure 3.6: Evoenergy – replacements by driver

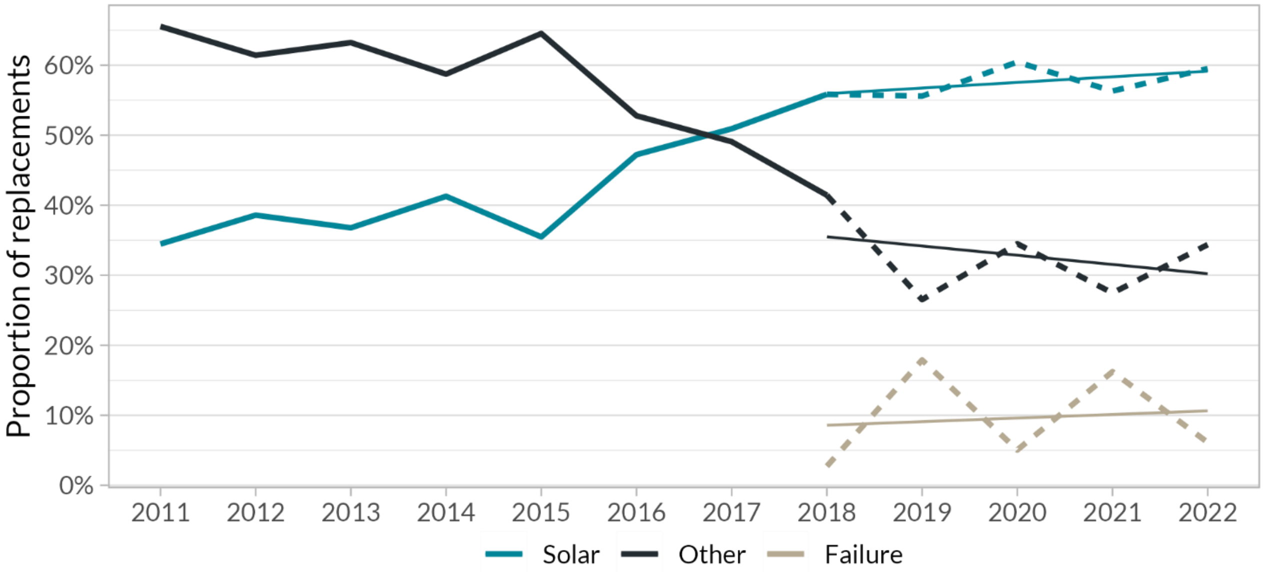


We observed that meter replacements due to the installation of solar-PV systems spiked in 2020 and 2021, before returning to a lower level in 2022. Replacements due to other retailer-initiated requests exhibited a similar pattern, but the average over the 2018 to 2022 period is broadly in line with that before 2018.

It is clear from figure 3.6 and the small sample period that fitting a trend to these categories of meter replacements after 2018 is not appropriate, ie, the trends are not statistically significant.

We present in figure 3.7 the proportion of total meter replacements by driver, instead of the absolute level.

Figure 3.7: Evoenergy – replacements by driver as a proportion of replacements



Since none of the trends after 2018 were statistically significant, in our view it is appropriate to disaggregate our total meter replacement forecast by reference to the average contribution of each driver over the period since the power of choice reforms came into effect, ie, such that:[11]

- 57.6% of meter replacements were driven by the installation of a solar PV system;
- 32.9% of meter replacements were initiated a retailer for a reason unrelated to solar PV systems; and
- 9.5% of meter replacements were caused by some form of meter failure, ie, a reactive or family failure.

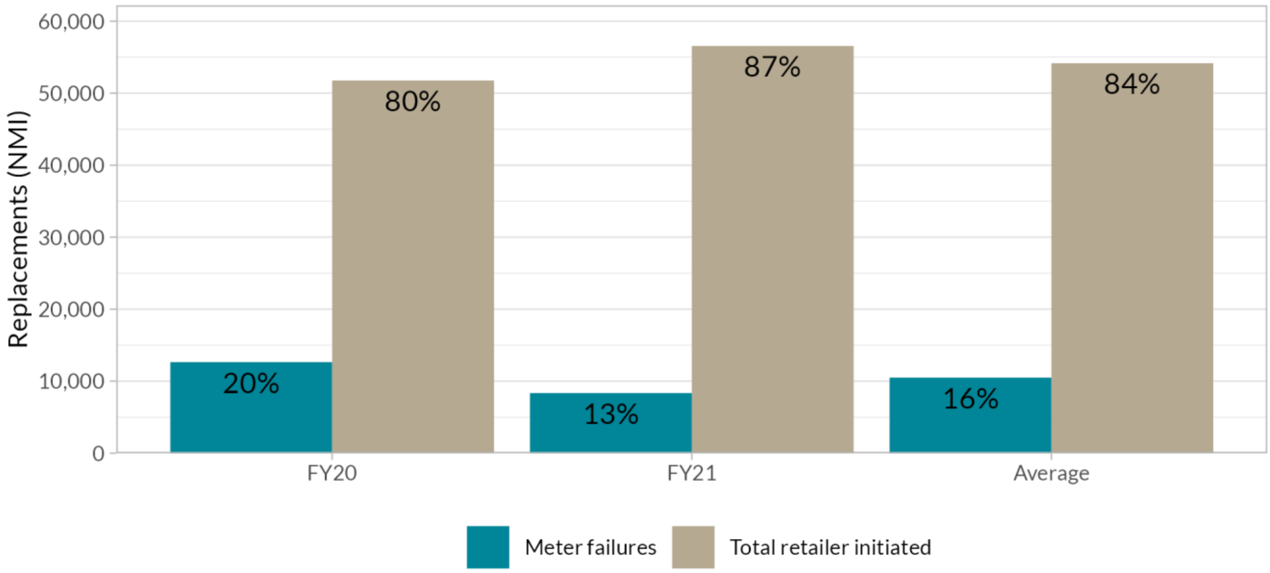
Ausgrid

The most robust source of data on the breakdown of Ausgrid's historical meter replacements is a targeted assessment undertaken by Ausgrid in the 2020 and 2021 years, at the network tariff level.

We present the aggregate breakdown of replacements caused by failure and (total) retailer-initiated requests in figure 3.8.

[11] Contributions to churn calculated at the remoteness area level and re-aggregated to the whole-DNSP level.

Figure 3.8: Ausgrid targeted assessment of replacements by failure and retailer-initiated requests



Note: Replacements presented are at the NMI level and therefore underestimate the number of actual meters replaced. Ausgrid estimates a NMI-to-meter factor of around 1.3.

We then estimated the proportion of total retailer-driven replacements caused by the installation of solar PV systems by reference to separate data that highlighted whether a replaced meter first recognised 'generation' around the time of the replacement.

We concluded that it is reasonable to assume that approximately 41.6 per cent of retailer-initiated replacements were caused by solar-PV installations. We can apply this factor to disaggregate total retailer-initiated replacements.

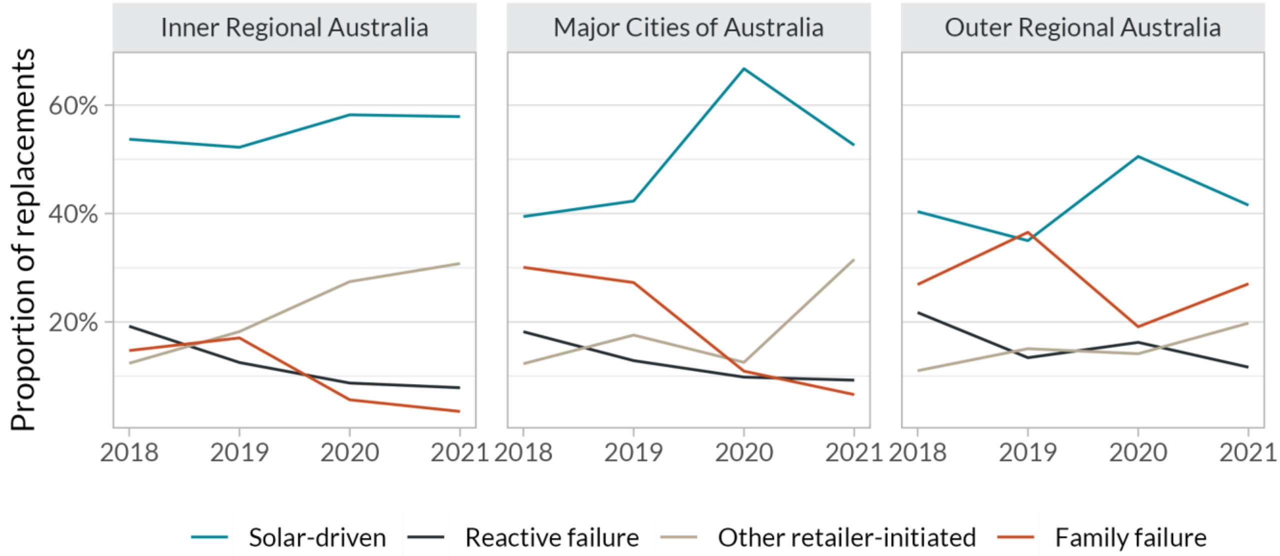
We therefore assumed that:

- 34.8% of meter replacements were driven by the installation of a solar PV system;
- 48.9% of meter replacements were initiated a retailer for a reason unrelated to solar PV systems; and
- 16.2% of meter replacements were caused by some form of meter failure, ie, a reactive or family failure.

Endeavour Energy

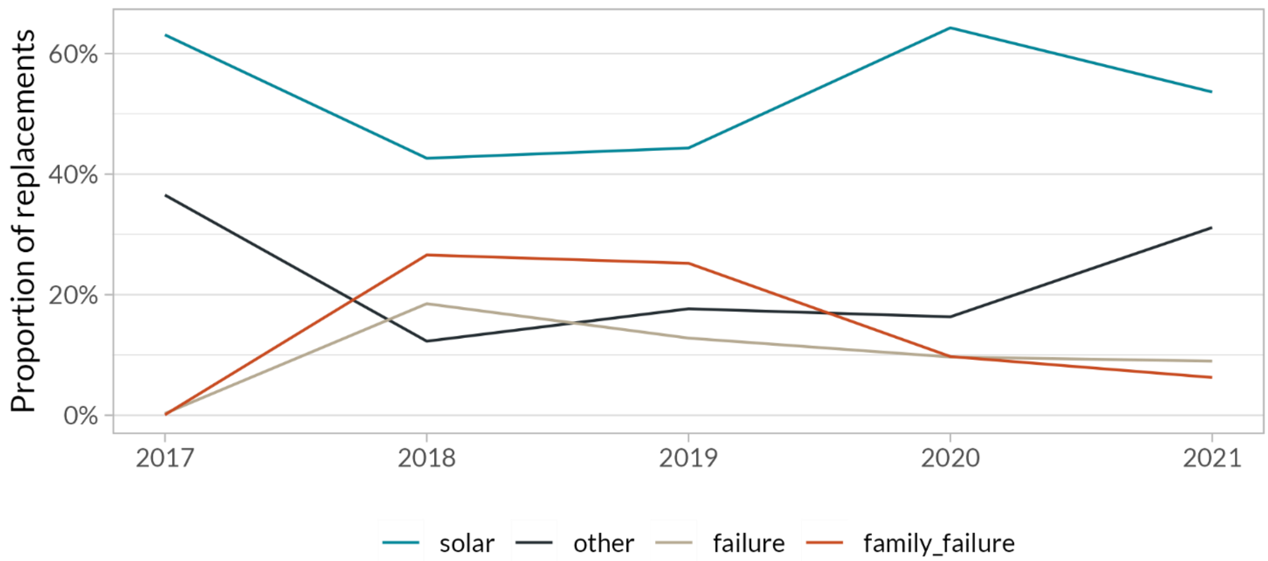
The data available to Endeavour Energy on meter replacements by driver relates to the 2018 to 2022 period and is also available by remoteness area. We illustrate these data in figure 3.9 and observe that the installation of solar PV systems is by far the most significant driver of meter replacements.

Figure 3.9: Endeavour – proportion of replacements by remoteness area



Looking across the whole of Endeavour's network, we can see that the proportion of solar replacements has generally hovered between 40 and 60 per cent of replacements.

Figure 3.10: Endeavour – Contribution of each driver to legacy meter replacements



Given the lack of statistical power (all trends on proportions are non-significant), we recommend that for the purpose of forecasting the components of churn we take the simple average of the proportion of replacements under each driver since Power of Choice, for each remoteness area.

For Endeavour, this results in an effective overall churn contribution of:

- 12.5 per cent for reactive meter failures;
- 17.1 per cent for meter family failures;

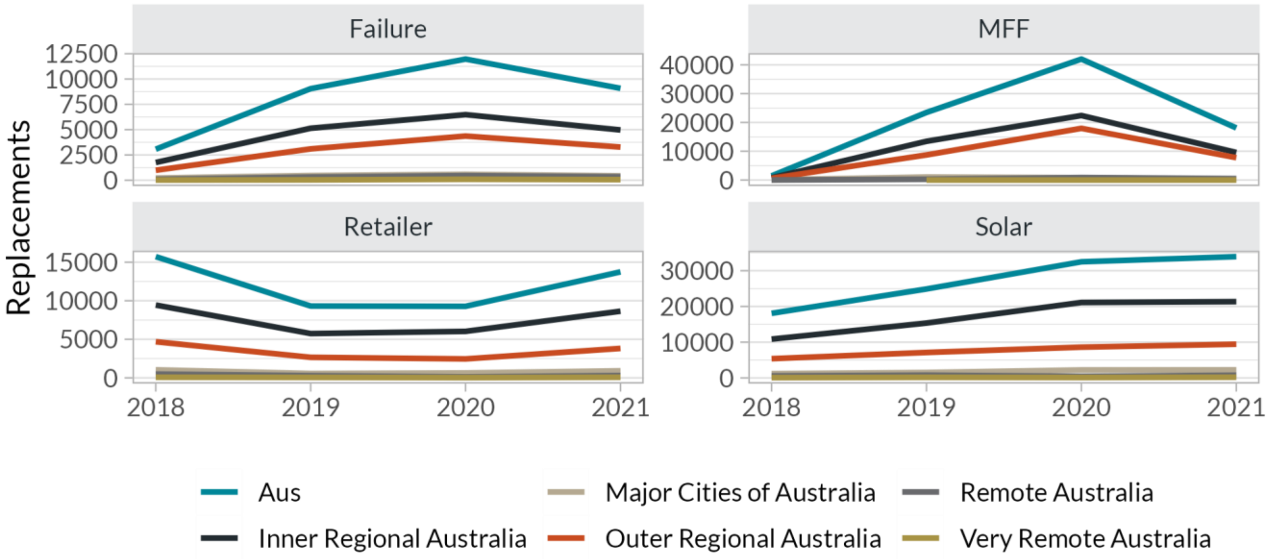
- 51.2 per cent for replacements driven by solar-PV installations; and
- 19.2 per cent for other retailer-initiated replacements.

Essential Energy

The most granular breakdown of Essential Energy's meter replacements is in the period after the introduction of the power of choice reforms. In these years it is possible to derive the level of meter replacements caused by each of the four drivers, in each remoteness area. The one exception is solar-driven replacements, which are not available by remoteness area. We therefore assumed that solar-driven replacements are distributed evenly across remoteness areas.

We illustrate these data in figure 3.11.

Figure 3.11: Essential – replacements by driver and remoteness



Our analysis indicated that there is a statistically significant trend only for solar-driven replacements. Modelling solar as a linear time trend indicates growth in total solar-driven replacements equal to 5,522 per year, with proportionally similar rates in each remoteness area over this period.

Evaluating the trend in solar-driven replacements over the period commencing in 2011, rather than in 2018, produces a statistically significant, linear time trend that indicates relatively lower growth in solar-driven replacements equal to 2,473 per year.

In our view, it is appropriate to use the longer assessment period to evaluate the trend in replacements caused by the installation of solar PV. We present the resulting forecast of solar-driven replacements in table 3.5.

Table 3.5: Essential Energy forecast meter replacements caused by solar-PV installations

FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
34,732	37,205	39,678	42,151	44,625	47,098	49,571	52,044

We then use fixed-proportions to disaggregate the remainder of total meter replacements.

We therefore assume that, of the meter replacements not caused by the installation of solar PV systems:[12]

- 19.5% are due to reactive meter failures
- 43.4% are caused by meter family failures; and
- 37.1% are driven by other retailer-initiated requests.

3.4 Conclusion

We present in table 3.6 our forecast of total meter replacements (as derived in section 3.3.2), broken down by driver.

Table 3.6: Forecast of legacy meter replacements by DNSP and churn driver

	FY23	FY24	FY25	FY26	FY27	FY28
Ausgrid						
Reactive faults	15,272	15,272	15,272	15,272	15,272	15,272
Family failures	-	-	-	-	-	-
Solar installations	32,745	32,745	32,745	32,745	32,745	32,745
Other	46,006	46,006	46,006	46,006	46,006	46,006
Total	**94,024**	**94,024**	**94,023**	**94,024**	**94,024**	**94,023**
Endeavour						
Reactive faults	8,094	8,094	8,094	8,094	8,094	8,094
Family failures	10,989	10,988	10,988	10,988	10,988	10,988
Solar installations	33,201	33,200	33,201	33,201	33,200	33,201
Other	12,545	12,544	12,545	12,545	12,544	12,545
Total	**64,829**	**64,826**	**64,828**	**64,828**	**64,826**	**64,828**
Essential						
Reactive faults	6,145	5,664	5,181	4,699	4,216	3,734
Family failures	13,678	12,605	11,531	10,458	9,384	8,311
Solar installations	37,205	39,678	42,151	44,625	47,098	49,571
Other	11,692	10,775	9,857	8,940	8,021	7,105
Total	**68,720**	**68,722**	**68,720**	**68,722**	**68,719**	**68,721**
Evoenergy						
Reactive faults	876	876	876	876	876	876
Family failures	-	-	-	-	-	-
Solar installations	5,247	5,246	5,247	5,247	5,246	5,246
Other	3,002	3,002	3,002	3,002	3,002	3,002
Total	**9,125**	**9,124**	**9,125**	**9,125**	**9,124**	**9,124**

As explained in section 3.1.3, this forecast establishes a clearly defined, empiric-based platform from which to assess any incremental effects arising from the future outcome of the AEMC's review.

For instance, we understand that Ausgrid has prepared scenarios of forecast meter replacements based on alternative policy settings that have the potential to arise from the AEMC's review of the regulatory framework for metering services, eg. achieving a 90 per cent penetration in smart meters by FY29 or FY32.[13]

[12] Contributions to churn calculated at the remoteness area level and re-aggregated to the whole-DNSP level.

[13] Ausgrid, *220404_Meter upgrade forecast.xlsx.*

These scenarios reflect a linear increase in failure-related replacements that is based a continuation of existing replacement trends and accelerated replacements due to alternative policy settings.

In our opinion, Ausgrid's adoption of scenario analysis is a reasonable response to the prevailing uncertainty as to policy settings, and the linear trend applied in those scenarios is also reasonable, noting that it allows for gradual increases in meter replacement resources over time.

4. Meter reading operating expenditure

In this section, we describe our approach to estimating the effect on meter reading operating expenditure of the decline in the stock of legacy meters.

We conduct a top-down analysis using DNSP metering data obtained from the Economic Benchmarking Regulatory Information Notices (RINs) and Category Analysis RINs.

We conclude from our extensive evaluation of alternative models and estimation techniques that there is no evidence of a statistically significant relationship between the stock of legacy meters and the cost of scheduled meter reading.

Importantly, this does not mean that meter reading costs are unrelated to the stock of meters. Rather, it suggests that relatively low levels of geographically dispersed meter replacements may not significantly decrease meter reading costs, because it results in relatively limited scope to optimise meter reading routes. That said, as the stock of meters falls in specific geographic areas, we expect that meter reading costs will fall in line with the reduction in the number and length of meter reading routes.

4.1 Data

We sourced data from the AER's category analysis and economic benchmarking RINs over the period from 2014 to 2021, prior to which consistent RIN data was not available for the businesses for which we sourced data. We compiled a panel dataset comprising six variables for each of six DNSPs, ie:

- the level of scheduled metering expenditure, expressed in 2021 dollar terms;
- the number of type 5 meters;
- the number of type 6 meters;
- the length of each network;
- the total number of customers; and
- the total number of residential customers.

We include in Appendix A1 the data we sourced from the RINs.

From these data we derived two additional variables, ie:

- the share of type 6 meters, calculated as the number of type 6 meters divided by the sum of type 5 and type 6 meters; and
- the share of commercial customers, calculates as one minus the number of residential customers as a proportion of total customers.

The DNSPs included in this data set are Ausgrid, Endeavour Energy, Essential Energy, Ergon, Evoenergy, and TasNetworks. We excluded SA Power Networks and Energex because their category analysis RINs did not have values for scheduled meter reading costs. We excluded DNSPs from Victoria because the data available for those DNSPs reflects fundamentally different circumstances, ie, a much faster and targeted replacement program. We discuss the relevance of these considerations and present separate results drawing on data from Victoria in 4.6.

Our analysis also drew upon the number of legacy meters that each DNSP had in each remoteness area over the assessment period, as discussed in section 3.1.2.

4.2 Relevance of a geospatial cost function

It is intuitive that the relationship between meter stock and the cost of reading meters is likely to be different in rural and urban areas, eg, due to a range of factors including differences in meter density and the predominant mode of transport for meter readers.

It follows that meter reading is likely to have different cost functions in different areas of the network.

The principal challenge associated with drawing out this relationship is that geospatially disaggregated records of meter reading costs are not available. This means that it is not possible to separately define and estimate a meter reading cost function in each area.

In this context, we had available as a dependent variable only *total* scheduled meter reading costs for each DNSP in each year. We tested a wide range of model specifications with geospatial explanatory variables for meters, all of which produced intractable or nonsensical results.

The best geospatial specification we developed was equivalent to the model we introduce in the following section, but with the explanatory variable for 'meters' replaced by two geospatial variables, ie:

- $Meters\_Urban_{it}$, comprising total meters across the major cities and inner regional remoteness areas in year 't' for DNSP 'i'; and
- $Meters\_Regional_{it}$, comprising total meters across the outer regional, remote and very remote areas.

This model produced statistically significant evidence that a one per cent decrease in meter stock resulted in a less than one per cent decrease in meter reading cost in each area, and that the relative reduction in meter reading cost was slightly greater in urban areas.

However, when taken together the coefficients on these two variables implied that, in aggregate, there are strong increasing returns to scale in meter reading costs, which is inconsistent with practical experience and observed relationships between meter stock and cost. This model specification is likely to be inappropriate because the underlying cost function reflects a multiplicative relationship between rural and urban meters, whereas they are more likely to relate to separate cost functions that sum to total meter reading cost.

We conclude from this analysis that the available data does not support a conclusion that there are geospatial differences in the relationship between meter stock and meter reading cost.

Nevertheless, there remain strong practical reasons why there are likely to be geospatial differences in the relationship between meter stock and meter reading cost.

4.3 Estimation techniques

We applied regression analysis to estimate each of the coefficients in the equations that we present in the following section. Regression analysis is an empirical method that uses the observed correlation between two variables to estimate the effect of a change in one variable on the other.

In this section we describe our assessment of the statistical properties of the variables that we relied upon and the estimation techniques we applied.

4.3.1 Non-stationary variables

A stochastic process is stationary if the statistical properties of the variable do not change over time.[14] Gujarati (2006) explains that:[15]

> Broadly speaking, a stochastic process is said to be stationary if its mean and variance are constant over time and the value of the covariance between two time periods depends only on the distance or lag between the two time periods and not on the actual time at which the covariance is computed.

It is common for economic variables to be non-stationary since they are often subject to a trend through time, such that the mean of a sample depends on the point in time at which it is taken. For example, Wooldridge (2012) notes that:[16]

> A process with a time trend... is clearly nonstationary: at a minimum, its mean changes over time.

The variables in an equation must be stationary for the ordinary least squares (OLS) estimation technique to produce reliable estimators. OLS estimation of equations that are specified with non-stationary variables produces a spurious regression, which cannot be relied upon.[17]

Highly statistically significant coefficients and a very high value for R-squared are hallmarks of incorrectly applying OLS to estimate coefficients on non-stationary variables.[18]

We tested each candidate variable for stationarity using the Levin et al (2002) test.[19]

The results indicated that the stock of legacy meters and the share of type six meters were non-stationary, reflecting their downwards trend through time. An augmented Dickey-Fuller test further identified that both variables were a unit-root process,[20] which can be described as:[21]

> A highly persistent time series process where the current value equals last period's value, plus a weakly dependent disturbance.

A unit root process is often referred to as 'difference stationary' process, since the first difference of the process is generally stationary.[22] First differencing is a transformation in which each observation x_t is replaced with a value calculated equal to $\Delta x_t = x_t\text{-}x_{t-1}$.

We eliminated the unit root by first-differencing all variables in our equations, and we then applied the Levin et al (2002) test to confirm that the resulting variables were stationary.[23]

[14] More formally, a stochastic process (x_t *t=1,2,3…*) is stationary if for every collection of indices $1\leq t_1 \leq t_2 \leq \ldots \leq t_m$, the joint distribution of ($x_{t1},x_{t2},\ldots x_{tm}$) is the same as the joint distribution of ($x_{t1+h},x_{t2+h},\ldots x_{tm+h}$) for all integers $h\geq 1$. See, for example: Wooldridge, J, *Introductory econometrics - A modern approach*, 5th edition, Cenage Learning, Boston, 2012, p 381.

[15] Gujarati, D, *Essentials of Econometrics*, Third Edition, McGraw Hill Irwin, 2006, p 496.

[16] Wooldridge, J, *Introductory econometrics - A modern approach*, 5th edition, Cenage Learning, Boston, 2012, p 381.

[17] Gujarati, D, *Essentials of Econometrics*, Third Edition, McGraw Hill Irwin, 2006, p 496.

[18] The R-squared of a regression is the proportion of the variation in the dependent variable that is explained by the explanatory variables in a regression.

[19] We test for stationarity using the Levin et al (2002) test from the *plm* package in R. See: Levin, A, Lin, CF and Chu, CSJ, *Unit root tests in panel data: asymptotic and finite-sample properties*, Journal of Econometrics, 108, 2002, pp 1-24.

[20] Formally, an augmented Dickey-Fuller test tests the null hypothesis that a unit root is present. We applied the panel covariate-augmented Dickey Fuller test developed by Constantini and Lupi. See: Constantini, M and Lupi, C, *A simple panel-CADF test for unit roots*, Oxford Bulletin of Economics and Statistics, 2012.

[21] Wooldridge, J, *Introductory econometrics - A modern approach*, 5th edition, Cenage Learning, Boston, 2012, p 860.

[22] Wooldridge, J, *Introductory econometrics - A modern approach*, 5th edition, Cenage Learning, Boston, 2012, pp 396 and 431.

[23] We test for stationarity using the Levin et al (2002) test from the *plm* package in R. See: Levin, A, Lin, CF and Chu, CSJ, *Unit root tests in panel data: asymptotic and finite-sample properties*, Journal of Econometrics, 108, 2002, pp 1-24.

Estimating all equations in first differences leaves the interpretation of the coefficients unchanged by nature of the relationship between each original equation and its first-differenced variant. However, we note that the intercept term in the original equation is cancelled out by the differencing process, and that the coefficient on the time trend in the original equation becomes the new intercept term in the differenced equation.

4.3.2 Estimation techniques

We considered the following panel regression models as part of our analysis:

- pooled regression model;
- fixed effects model; and
- random effects model.

The pooled regression model is equivalent to carrying out a simple linear regression across the entire panel dataset. This model estimates one set of coefficients for the dataset, which are assumed to be constant across all DNSPs and years.[24]

A fixed effect model controls for the effect on meter reading cost of any unobserved, DNSP-specific factors that do not vary through time. In practice, it is applied by modifying the pooled regression model through the inclusion of a dummy intercept variable for each DNSP.

The random effects model is similar but involves the addition of a DNSP-specific random (rather than fixed) term in the intercept for each DNSP.

However, first-differencing the models removes these DNSP-specific terms for the same reason as an overall intercept term as explained above, ie, they are essentially cancelled out because the first difference removes time invariant model components.

We therefore apply the pooled approach to the first-differenced models.[25]

Having considered the appropriate estimation models, we evaluated the error terms for serial correlation, which occurs when the error term in a regression is correlated over time. A Breusch-Godfrey/Wooldridge test for serial correlation in panel models rejected the null hypothesis that the pooled regression generates uncorrelated errors at a five per cent level of significance.

We therefore adopted the Prais-Winsten feasible generalised least squares procedure to adjust for autocorrelation and generate panel-corrected standard errors.[26]

Our econometric analysis suggests that the most appropriate regression model is the pooled regression model with corrections for autocorrelated and heteroskedastic errors.[27]

[24] It is necessary to omit the intercept term if each DNSP is assigned its own dummy variable. An alternative approach is to include the intercept term while assigning dummy variables to all but one DNSP. This generates the same coefficients for all other explanatory variables in the model, but has a different interpretation for the intercept and dummy variables.

[25] For completeness and noting the issues related to non-stationarity, we tested appropriateness of a fixed effect and random effect model (not first-differenced). A partial-F test indicated that fixed effects were statistically significant at a five per cent level, but the resulting coefficient on the meters variable was negative. A Breusch-Pagan test failed to reject the null hypothesis of ‘no random effects’ at five per cent level of significance.

[26] We use the *panelAR* package in R to estimate a pooled regression that uses the Prais-Winsten feasible generalised least squares procedure to adjust for autocorrelation and generate panel-corrected standard errors. See: Greene, WH, *Econometric Analysis | International Edition*, Seventh Edition, Pearson, Essex, England, 2012, pp 316-317, 964-967.

[27] We also tested a range of other models, such as a model which includes a variable for the number of meter reads undertaken by a DNSP. However, this model did not result in materially different estimates and may also suffer from collinearity between meters reads and meters (since most meters are read four times per year). This specification is analogous to the model that the ACCC accepted in its decision for Australia Post in 2015. The ACCC accepted Australia Post’s price notification supported by an econometric model that includes ‘labour, capital, and other inputs’, ‘articles delivered’, ‘points delivered to’, and ‘distance covered on delivery round’ as explanatory variables. Our alternative specification used the number of scheduled meter reads as an explanatory variable since it is

4.4 Model specification

In this section we describe the model specifications we used to assess the relationship between the stock of legacy meters and the cost of reading meters.

Our base model specification is the following Cobb-Douglas cost function, ie:[28]

$$Cost_{it} = \beta_0 + \beta_1 Meters_{it} + \beta_2 Route\ length_{it} + \beta_3 Share\ commercial_{it} + \beta_4 Share\ type\ 6_{it} + \beta_5 Year_t + u_{it}$$

where each parameter (aside from the *Year*) represents the natural logarithm of a variable, as set out in table 4.1 below.

Table 4.1: Variables in cost equation

Parameter	Explanation
$Cost_{it}$	• natural logarithm of operating cost of scheduled meter reading in year 't' for DNSP 'i'
$Meters_{it}$	• natural logarithm of number of type 5 meters plus number of type 6 meters in year 't' for DNSP 'i'
$Route\ length_{it}$	• natural logarithm of network length in year 't' for DNSP 'i'
$Share\ commercial_{it}$	• natural logarithm of share of commercial customers in year 't' for DNSP 'i'
$Share\ type\ 6_{it}$	• natural logarithm of share of type 6 meters in year 't' for DNSP 'i'
u_{it}	• random error whose characteristics are consistent with the assumptions of a panel regression model[29]

Since we estimate each equation in first differences, as described in section 4.3.1, we express our base model specification as:

$$\begin{aligned}(1a)\ Cost_{it} - Cost_{it-1} &= \beta_0 - \beta_0 + \beta_1 Meters_{it} - \beta_1 Meters_{it-1} + \beta_2 Route\ length_{it} - \beta_2 Route\ length_{it-1} \\ &+ \beta_3 Share\ commercial_{it} - \beta_3 Share\ commercial_{it-1} + \beta_4 Share\ type\ 6_{it} - \beta_4 Share\ type\ 6_{it-1} \\ &+ \beta_5 Year_t - \beta_5 Year_{t-1} + u_{it} - u_{it-1}\end{aligned}$$

This equation can be further simplified and expressed as:

$$(1a)\ \Delta Cost_{it} = \beta_1 \Delta Meters_{it} + \beta_2 \Delta Route\ length_{it} + \beta_3 \Delta Share\ commercial_{it} + \beta_4 \Delta Share\ type\ 6_{it} + \beta_5 + \Delta u_{it}$$

Importantly, each of the coefficients in equation 1(a) is the same as in the base model specification above, such that their interpretations remain unchanged.

analogous to the 'articles delivered' variable in Australia Post's model. See: Economic Insights, *Updated Estimates of Australia Post's Mail Centre and Delivery Centre Cost Elasticities*, 14 May 2015.

[28] We note that a similar model specification formed the basis of the AER's final determination for Ausgrid for the current regulatory control period, as relevant to the meter reading component of metering opex. We allow network length to vary across the assessment period, whereas it was held constant in that earlier analysis. See: See: Sankofa, *Diseconomies of scale in meter reading | The impact of declining meter density on meter reading costs*, January 2018, pp 26, 34-36; AER, *Draft Decision – Ausgrid Distribution determination 2019 to 2024 Attachment 15 – Alternative control services*, November 2018, pp 28-30; and AER, *Final Decision – Ausgrid Distribution Determination 2019 to 2024 Attachment 15 Alternative control services,* April 2019, p 19.

[29] That is, the random error is assumed to be exogenous with zero mean and constant variance (homoscedastic).

We also tested a simpler specification with less explanatory variables, ie:

$$(2a)\ \Delta Cost_{it} = \beta_1 \Delta Meters_{it} + \beta_2 + u_{it}$$

We also estimate linear versions of equations 1(a) and 2(a) – ie, where we do not take the natural logarithm of each variable – which we refer to as equation 1(b) and 2(b), respectively.

4.5 Results

We summarise the results of our regression analysis in table 4.2.

Table 4.2: Summary of pooled regression results

Equation	Constant	**Meters**	Route length	Share commercial	Share type 6	Year	Adj. R^2
1a	*NA*	**-0.67 (0.39)**	-0.50 (0.29)	-0.98 (1.22)	0.13 (0.41)	-0.03 (0.02)	0.1384
1b	*NA*	**-8.41* (3.69)**	220 (151)	26M (63M)	772K (1M)	-296K (156K)	0.0846
2a	*NA*	**-0.97** (0.35)**				-0.04 (0.03)	0.0489
2b	*NA*	**-8.50 (4.22)**				-278K (171K)	0.0622

*Note: Standard errors are shown in parentheses under the coefficient estimates. Significance: '***' 0.1 per cent; '**' 1 per cent; '*' 5 per cent. First difference regressions are not able to estimate the constant term in the original equation as it is essentially 'cancelled out' by the differencing process. The constant term estimated in the first-differenced regression is equivalent to the parameter on the Year variable in the original equation.*

The coefficient on the Meters variable, in bold in table 4.2, represents an estimate of:

- the per cent change in meter reading cost caused by a one per cent change in meter stock for equations (1a) and (2a); and
- the unit change in meter reading costs caused by a one unit change in meter stock for equations (1b) and (2b).

Of the four equations that we estimate, two have a coefficient on the meters variable that is statistically significant, ie, equations (1b) and (2a).[30] However, the negative coefficients indicate that a decrease in the stock of meters would be expected to *increase* the cost of meter reading. In our opinion it is inappropriate to assign any weight to these counter-intuitive estimates of the relationship between meter stock and meter cost.

We also note that the low r-squared values for each regression indicate that only a small proportion of the variation in scheduled meter reading costs are explained by the explanatory variables in our equations.

We discuss the conclusions we draw from this analysis section 4.6.

[30] The five per cent level is a widely accepted standard for evaluating the statistical significance of statistical analyses. For example, see: Federal Judicial Centre, Reference manual on scientific evidence, Third Edition, 2011, pp 291-292 and 320-321. Available at: https://www.fjc.gov/content/reference-manual-scientific-evidence-third-edition-1.

4.6 Conclusion

We conclude from our extensive evaluation of alternative models and estimation techniques that there is no evidence of a statistically significant, positive relationship between the stock of legacy meters and the cost of scheduled meter reading.

This conclusion reflects the disparity between:

- the stable stock of legacy meters over the period to 2017, followed by a steady decline thereafter; and
- the volatile and mixed trends in meter reading costs, and that meter reading costs have generally been stable or increasing since the end of 2017.

We illustrate the time profile of the stock of legacy meters and meter reading cost in figure 4.1 and figure 4.2, respectively, indexed to a value of one in 2014.

Figure 4.1: Stock of legacy meters, indexed to a value of one in 2014

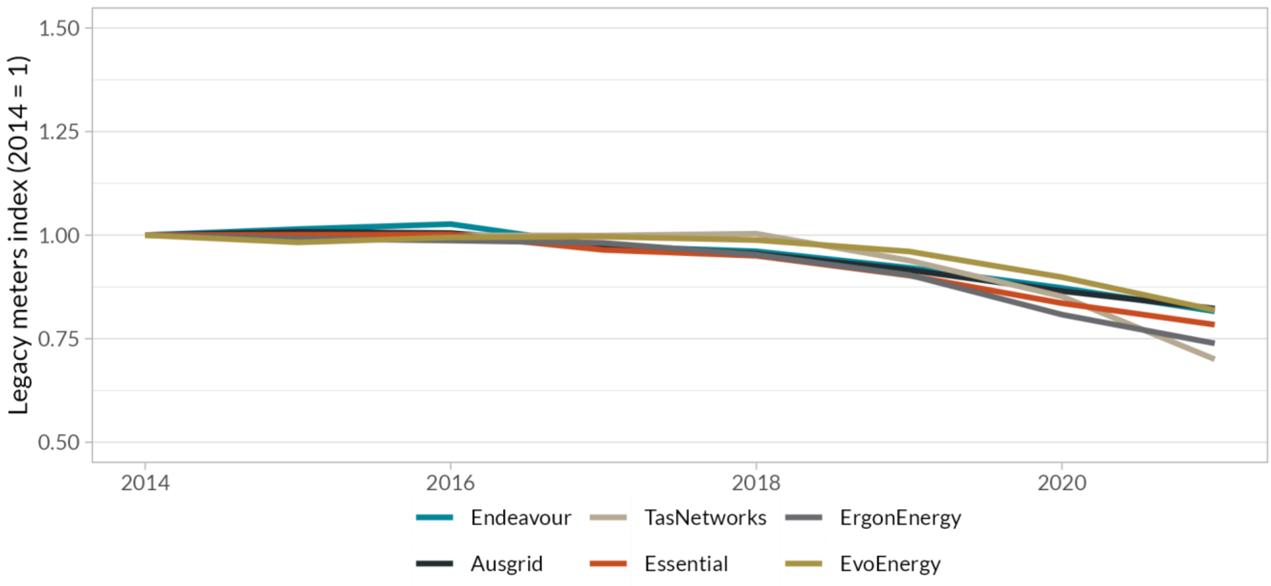
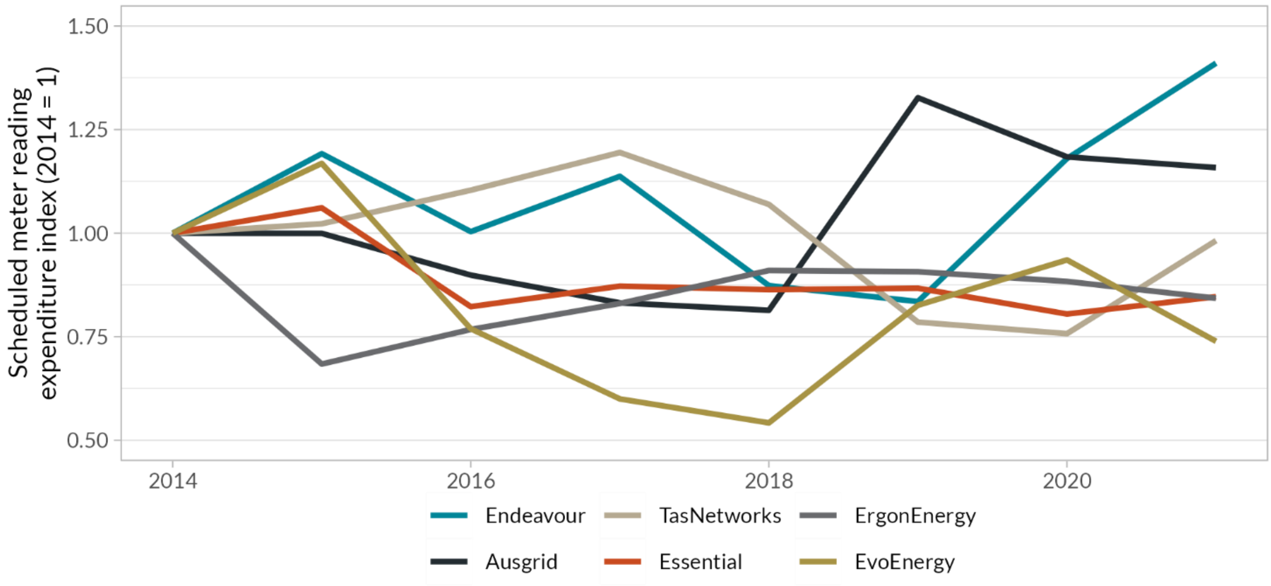


Figure 4.2: Scheduled meter reading cost, indexed to a value of one in 2014



The absence of a relationship between the observed decline in meter stock and the cost of reading meters is consistent with the untargeted, dispersed replacement of legacy meters by responsible third parties to date, which is described in section 2.4.

This has limited the scope for route optimisation and, in turn, limited the cost efficiencies that can be achieved by DNSPs. In the absence of route optimisation meter readers travel past the location of meters that have been replaced, which the data suggests results in no material reduction in the cost of completing those routes.

We conclude that the historical data provides no evidence that the continued, ad hoc replacement of legacy meters will materially reduce the cost of meter reading in the next regulatory control period.

4.6.1 Possibilities for future assessment

Although the data provides no evidence that the ad hoc replacement of legacy meters will materially reduce the cost of meter reading in the next regulatory control period, it is intuitive that even the ad hoc replacement of legacy meters will, at some point, enable cost savings through route optimisation.

The extent of historical route optimisation and cost savings is unlikely to shed light on when this might occur due to its limited scope and effect on cost, putting aside the commercial sensitivity of the necessary data.[31]

Identifying when, and to what extent, the ad hoc replacements of meters would result in material cost savings requires a forward-looking evaluation of route optimisation scenarios based on assumptions as to the geographic dispersion of future meter replacements.

In practice, it is reasonable to expect that the periodic re-setting of the per-unit cost of meter reading incurred by DNSPs will reflect forward-looking expectations as to the cost of those services, taking into account the unit cost changes as the meter population falls.

[31] We note that Ausgrid, Essential Energy and Evoenergy engage third party contractors to undertake read meters, whereas Endeavour Energy has an alliance with UGL Limited.

4.6.2 Implications of a geographically targeted replacement programme

It is uncontroversial that the targeted, *efficient* replacement of legacy meters has the potential to reduce the cost of meter reading.

The evidence indicates that material reductions in meter reading costs are likely to rest on enabling significant route optimisation through geographically targeted meter replacements. This would enable existing meter routes to be materially shortened or avoided altogether.

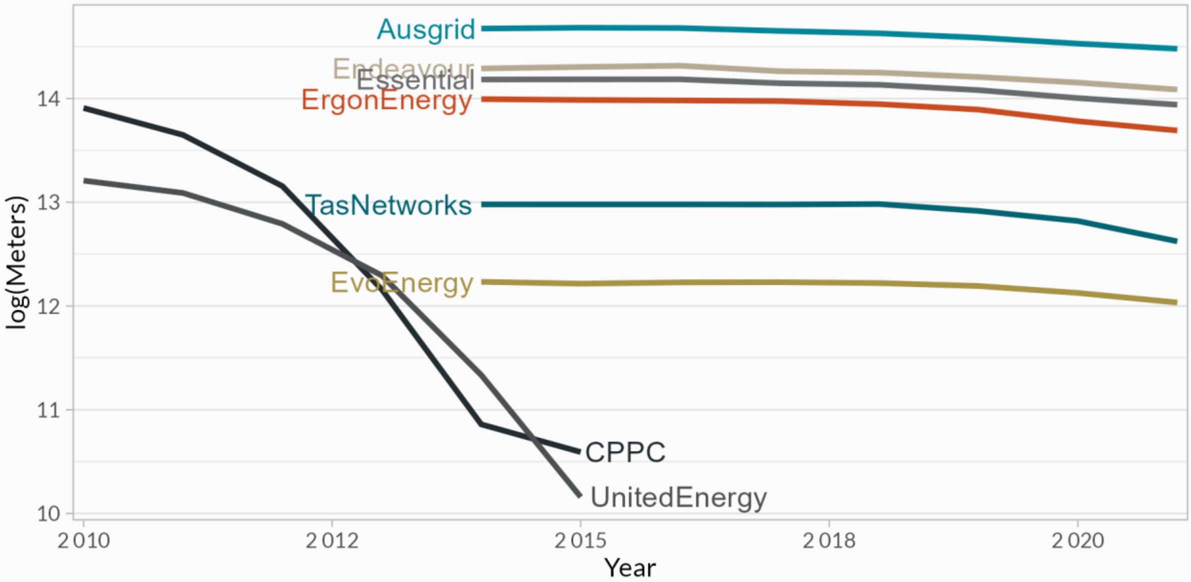
A tipping point in cost saving would likely occur, particularly in rural areas, when replacement programs create discrete geographic areas that have no legacy meters.

In our opinion, this should be a focus of the AEMC's review of the regulatory framework for meter replacements.

By way of providing context to the potential effects on meter reading cost of a more rapid and targeted roll-out of smart meters, we applied the same analysis described above to data relating to DNSPs in Victoria over the 2010 to 2015 period, which reflected a much faster, DNSP-led replacement program. We summarise this analysis in box 1.

Box 1: Experience of Victorian DNSPs

The figure below illustrates the comparatively faster pace of the legacy meter replacement program for CitiPower/Powercor and United Energy in Victoria,[32] reflecting that it was undertaken on a fundamentally different basis, eg, it was led by the DNSPs.



Our analysis showed that the data exhibited the same non-stationary problems as the NSW and ACT data. After correcting for non-stationarity by taking first differences, the application of the same approach that we describe above, but using data in relation to only CitiPower/Powercor and United Energy, indicated that the coefficient on the *Meters* variable was:[33]

- 0.797 and statistically significant at the 0.1 per cent level, using equation 1a; and.
- 0.582 and statistically significant at the 5 per cent level, using equation 2a.

The mid-point of these statistically significant estimates is equal to 0.69. This suggests that a faster and targeted meter replacement program may mean that, for each one per cent change in the stock of legacy meters, the cost of reading legacy meters reduces by 0.69 per cent.

This estimate may be informative in circumstances where the AEMC's review of the regulatory framework for metering services results in a much faster and targeted meter replacement program.

If a DNSP's objective is to promote regulatory consistency for its customers, prior to the completion of the AEMC's review it may also be reasonable to adopt the value that formed the basis of the AER's decision for the current regulatory period.

4.6.3 Comparison to historical analysis

Similar analysis to that presented in this section was undertaken by a consultant in connection with the preparation of a regulatory proposal for the 2019-2024 regulatory control period, which then informed the meter reading component of the AER's decision on the productivity factor for total metering opex.[34]

The regression analysis presented in that report concluded that a one per cent change in meter stock resulted in a 0.5 per cent change in scheduled meter reading expenditure.[35] However, the underling econometric analysis made no adjustment to account for the non-stationarity in any explanatory variables.

For completeness, we note that updating that analysis with no adjustment for non-stationarity – a spurious regression – would indicate that a one per cent change in meter stock resulted in a 0.68 per cent change in scheduled meter reading expenditure.[36] In our opinion, no weight can be assigned to the results of this spurious regression, for the reasons explained in section 4.3.

The other top-down approaches applied in that consultant's report were based on an assumed relationship between meter stock and the cost of meter reading, ie, that unit reading costs fall with the square root of the number of meters.[37]

The available data indicates that the application of a similar approach in this context would be inappropriate, since there is no evidence of a statistically significant relationship between meter stock and the cost of meter reading. Nevertheless, for completeness we note that the application of those assumed relationships in this context would produce the same result that was previously derived by the consultant, ie, for each one per cent change in the stock of meter readers over the next regulatory control period, the cost of meter reading will reduce by 0.5 per cent. We describe this analysis in more detail in appendix A2.

[32] We excluded AusNet Services because it had a very small number of meters across the whole period.

[33] None of the linear models resulted in a statistically significant coefficient on the *Meters* variable.

[34] Sankofa, *Diseconomies of scale in meter reading | The impact of declining meter density on meter reading costs*, January 2018.

[35] Sankofa, *Diseconomies of scale in meter reading | The impact of declining meter density on meter reading costs*, January 2018, p 28.

[36] Consistent with the hallmarks of incorrectly applying OLS to estimate coefficients on non-stationary variables, as described in section 4.3.1, this consultant's analysis had an adjusted R-squared above 99 per cent.

[37] Sankofa, *Diseconomies of scale in meter reading | The impact of declining meter density on meter reading costs*, January 2018, pp 29-30.

5. Productivity factor for total metering opex

In this section, we describe how DNSPs can derive a total productivity factor for metering operating expenditure for application in the AER's rate of change formula, consistent with the approach previously applied by the AER.

5.1 Base, step, trend approach

The AER prefers to assess a DNSP's proposed operating expenditure using its 'base step trend' approach.[38]

This involves evaluating a DNSP's proposed operating expenditure by reference to its actual operating expenditure in a recent year – the 'base year' – provided the AER's assessment of that 'revealed expenditure' does not identify any evidence that it is materially inefficient.

If the AER does not find any evidence that a DNSP's actual operating expenditure in the base year is materially inefficient, it then applies a 'rate of change' to project the efficient level of operating expenditure in future years, while applying additions or subtractions for step changes in costs that are not reflected in base year operating expenditure.

The rate of change applied by the AER in each year is calculated as follows:[39]

$$Rate\ of\ change_t = output\ growth_t + real\ price\ growth_t - productivity\ growth_t$$

Where:

$output\ growth_t$	is the forecast annual increase in output, where the AER notes that if the productivity measure includes economies of scale then forecast output growth should not be adjusted for economies of scale.
$real\ price\ growth_t$	is the forecast annual increase in the real price of inputs, where the AER notes that if the productivity measure includes labour productivity then real price growth should not be adjusted to remove labour productivity.
$productivity\ growth_t$	is the forecast annual increase in the real price of inputs, where the AER notes that if the productivity measure includes labour productivity then real price growth should not be adjusted to remove labour productivity.

5.2 Productivity factor for total metering operating expenditure

The operating cost of scheduled meter reading is only one component of a DNSP's total metering operating expenditure. Since the AER's rate of change formula applies to total metering operating expenditure, it is necessary to derive a *total* metering opex productivity factor.

A total metering opex productivity factor can be derived by evaluating the relationship between forecast meter stock and forecast total metering operating expenditure for a particular DNSP.

Total meter reading operating expenditure in each year of the regulatory control period can be estimated equal to the sum of:

- forecast meter reading operating expenditure;

[38] AER, *Expenditure forecast assessment guidelines for electricity distribution*, November 2013, p 22.

[39] AER, *Expenditure forecast assessment guidelines for electricity distribution*, November 2013, pp 23-24.

- the other components of total metering operating expenditure – metering operating expenditure exclusive of scheduled meter reading costs – which can be classified as:
  > fixed costs, which are expected to remain constant over the regulatory control period; and
  > variable costs, which are expected to scale linearly with meter stock, ie, a one per cent reduction in meter stock results in a one per cent reduction in variable 'other' metering opex.

We conclude in section 4 that the available data provides no evidence that a continued, small incremental decline in the stock of legacy meters over the next regulatory control period will reduce the cost of scheduled meter reading. This reflects our view that variable meter reading costs are most likely related to the number and length of meter reading routes, which have likely not changed significantly as the stock of legacy meters has declined.

However, if this expectation changes due to the future possibilities we highlight in 4.6, forecast scheduled meter reading costs could be estimated by reference to:

- the relative change in the stock forecast; and
- an estimate of the relative relationship between the change in meter stock and the cost of scheduled meter reading.

Having estimated the level of total metering operating expenditure in each year of a regulatory control period, the approach applied by the AER in the current regulatory control period[40] involved then estimating the coefficient in the regression:

$$\log(total\ metering\ opex_t) = constant + \beta_1 \log\,(meters_t)$$

The coefficient β_1 in this regression represents the per cent change in total metering operating expenditure associated with a one per cent change in meter population. The AER referred to this value as the 'productivity factor'.

The definition of this value means that its application must account also for the percentage change in meter stock from year to year. The most straight-forward means by which to incorporate it into the rate of change formula is to set the output growth input to the rate of change equal to zero, and then calculate the productivity growth input equal to:

$$Productivity\ growth_t\ = e^{(\log\,(meters_t) - \log\,(meters_{t-1}))*\beta_1}$$

This is consistent with the approach applied by the AER in its final decisions for the New South Wales DNSPs for the 2019 to 2024 regulatory control period.[41]

In those final decisions the AER forecast operating expenditure by calculating $Productivity\ growth_t$ based on the productivity factor (β_1) determined in its draft decision and a revised meter stock forecast.

Since the productivity factor (β_1) is itself a function of the meter stock forecast, in our view it would be preferable to reapply the process described in this section if there is a subsequent proposal or decision based on a revised meter stock forecast.

[40] AER, *Draft decision – Ausgrid Distribution determination 2019 to 2024 Attachment 15 – Alternative control services*, November 2018, p 29.

[41] For example, see: AER, *Ausgrid 2019-24 - Draft decision - Attachment 8.03 - Metering PTRM and pricing model - November 2018*, 'AER productivity factor' worksheet; and AER, *Endeavour Energy 2019-24 - Draft decision - 14.06 Metering Pricing Model - November 2018*, 'AER recalculating opex' worksheet.

A1. Data collected from the Economic Benchmarking RIN and Category Analysis RIN

Table 5.1 sets out the RIN data that we use to generate estimates from our top-down econometric analysis and from the approaches in regulatory literature. As section 4.1 describes, the dataset contains 48 observations for six DNSPs spanning eight years from 2014 to 2021. The cost variable has been transformed to the same units as the 2021 RINs, ie FY21 dollars.

Table 5.1: Metering data collected from RINs

DNSP	Cost	Meters	Route Length	Type 6 meters	Customers	Residential	Meter reads
Ausgrid	8,514,893	2,360,620	37,334	1,713,902	1,651,160	1,463,205	6,661,990
Ausgrid	8,510,095	2,379,192	38,687	1,727,152	1,669,559	1,482,986	6,727,754
Ausgrid	7,652,229	2,372,396	38,913	1,720,716	1,688,282	1,504,478	6,839,192
Ausgrid	7,082,059	2,306,490	39,038	1,708,592	1,706,914	1,524,732	6,670,101
Ausgrid	6,929,735	2,254,202	39,250	1,679,829	1,727,294	1,545,428	6,773,437
Ausgrid	11,298,293	2,162,363	39,348	1,599,814	1,746,274	1,564,021	6,708,041
Ausgrid	10,083,322	2,041,920	39,515	1,535,814	1,762,079	1,578,910	6,834,969
Ausgrid	9,861,755	1,942,512	39,675	1,480,220	1,774,204	1,590,154	5,750,578
Endeavour	9,916,724	1,606,565	28,090	1,606,565	940,029	830,658	3,604,272
Endeavour	11,819,258	1,630,037	28,221	1,630,037	955,833	843,867	3,665
Endeavour	9,953,058	1,649,450	28,347	1,649,450	968,355	859,445	3,803,628
Endeavour	11,277,067	1,564,148	27,128	1,564,148	984,230	879,357	3,816,992
Endeavour	8,661,232	1,543,992	27,922	1,543,992	1,005,562	899,491	3,937,621
Endeavour	8,279,907	1,480,013	28,352	1,480,013	1,027,586	920,306	3,937,483
Endeavour	11,703,357	1,401,846	29,466	1,401,846	1,049,165	941,550	3,284,930
Endeavour	13,985,789	1,311,084	29,813	1,311,084	1,067,349	959,048	3,244,632
Essential	13,664,647	1,444,945	180,741	1,444,667	854,231	715,400	8,540,424
Essential	14,499,387	1,446,253	181,384	1,445,975	867,001	725,879	8,807,059
Essential	11,239,627	1,447,291	181,700	1,447,017	879,065	732,081	8,799,013
Essential	11,917,271	1,393,511	181,657	1,393,247	891,935	740,780	9,032,370
Essential	11,800,997	1,373,076	181,778	1,372,802	905,970	748,446	9,091,337
Essential	11,849,155	1,304,149	181,954	1,303,865	916,471	756,263	9,284,879
Essential	10,997,646	1,207,525	181,874	1,207,258	925,966	764,058	8,791,216
Essential	11,567,207	1,132,683	182,064	1,132,454	935,179	771,827	9,946,061
EvoEnergy	1,393,753	205,470	4,088	139,320	178,710	163,001	2,228,300
EvoEnergy	1,628,450	201,900	2,306	125,000	181,851	163,664	2,385,600
EvoEnergy	1,071,984	204,338	4,114	121,952	184,962	166,469	798,500
EvoEnergy	836,063	204,721	4,128	117,508	191,482	172,360	836,157
EvoEnergy	755,440	203,041	4,114	114,587	197,537	177,394	832,138
EvoEnergy	1,151,140	197,376	4,255	110,523	203,157	183,253	833,083
EvoEnergy	1,303,687	184,618	4,276	183,370	207,237	188,006	842,885
EvoEnergy	1,029,931	168,310	4,314	167,956	212,505	192,476	820,550
ErgonEnergy	11,088,267	1,195,801	141,845	1,195,801	721,930	607,276	#N/A

DNSP	Cost	Meters	Route Length	Type 6 meters	Customers	Residential	Meter reads
ErgonEnergy	7,584,947	1,185,820	140,013	1,185,820	728,291	615,781	3,047,639
ErgonEnergy	8,510,292	1,180,272	140,415	1,180,272	739,354	624,525	3,098,196
ErgonEnergy	9,205,708	1,173,238	140,567	1,173,238	745,501	627,613	3,131,585
ErgonEnergy	10,088,910	1,139,129	140,359	1,139,129	752,141	633,660	3,105,992
ErgonEnergy	10,055,749	1,080,885	140,838	1,080,885	757,726	638,634	3,048,722
ErgonEnergy	9,796,072	966,396	141,230	966,396	762,303	642,763	2,827,321
ErgonEnergy	9,346,077	883,492	141,894	883,492	767,583	647,875	2,604,767
TasNetworks	2,182,718	433,400	18,166	433,400	280,750	235,170	2,068,430
TasNetworks	2,232,108	433,300	20,427	433,300	283,059	237,366	1,980,077
TasNetworks	2,409,110	433,331	20,430	433,331	285,325	239,781	2,168,231
TasNetworks	2,607,712	432,981	20,210	432,981	287,652	241,955	2,210,100
TasNetworks	2,334,184	434,899	20,684	434,899	287,936	244,282	2,083,230
TasNetworks	1,713,925	406,854	20,487	406,854	290,446	246,751	2,025,904
TasNetworks	1,653,207	369,318	17,244	369,318	293,949	249,805	3,289,154
TasNetworks	2,143,251	303,577	17,256	303,577	297,656	253,137	1,749,085

Source: RIN data, HoustonKemp analysis.

A2. Mott MacDonald and Frontier approach

Ausgrid's proposal for the 2019-24 regulatory period includes two models from UK regulatory literature, ie:[42]

- an approach from a report by Mott MacDonald for the UK Department of Business, Enterprise and Regulatory Reform; and
- an approach from a report by Frontier Economics for Centrica.

A2.1 Mott MacDonald approach

The Mott MacDonald approach estimates meter reading costs using the following equation:[43]

$$c = PRC\sqrt{M/m}$$

Where:

- *c* is the meter reading cost;
- *M* is the original number of legacy meters;
- *m* is the number of legacy meters remaining; and
- *PRC* is the original cost of reading a legacy meter, ie, when *m* = *M*.

Table A2.1 sets out our estimates of meter reading costs for each DNSP when applying the Mott MacDonald approach to FY21 RIN data.

[42] See: Sankofa, *Diseconomies of scale in meter reading | The impact of declining meter density on meter reading costs*, January 2018, pp 29-30.

[43] We have not been able to access the Mott MacDonald report. As such, we rely on the information set out in the report by Ausgrid's consultant, Sankofa.

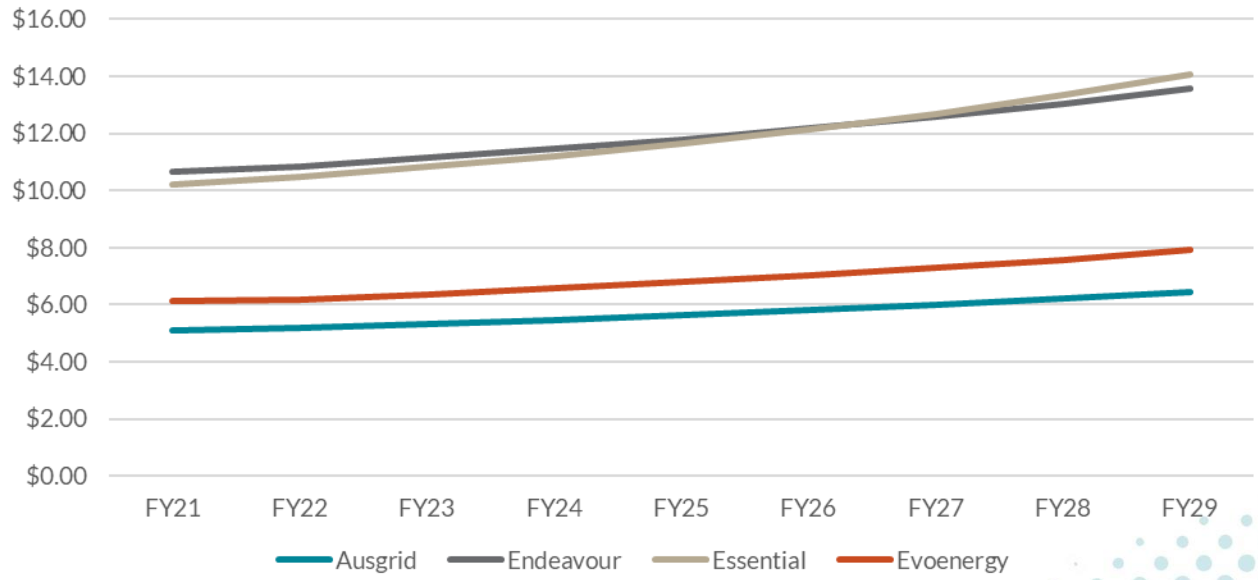
Table A2.1: Metering cost estimates using Mott MacDonald approach

	FY21*	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Ausgrid: $Cost_{2021}$ = 9,861,755; M_{2021} = 1,942,512; $PRC_{2021} = \$5.08$ per meter per year									
Remaining meters (*m*)	1.94M	1.86M	1.77M	1.67M	1.58M	1.48M	1.39M	1.30M	1.20M
Meter reading cost (*c*)	$9.86M	$9.65M	$9.40M	$9.15M	$8.89M	$8.62M	$8.34M	$8.05M	$7.76M
Unit cost per year (*c / m*)	$5.08	$5.19	$5.33	$5.47	$5.63	$5.81	$6.00	$6.22	$6.46
Endeavour: $Cost_{2021}$ = 13,985,789; M_{2021} = 1,311,084; $PRC_{2021} = \$10.67$ per meter per year									
Remaining meters (*m*)	1.31M	1.27M	1.20M	1.14M	1.07M	1.01M	0.94M	0.88M	0.81M
Meter reading cost (*c*)	$13.99M	$13.74M	$13.39M	$13.02M	$12.64M	$12.25M	$11.85M	$11.44M	$11.01M
Unit cost per year (*c / m*)	$10.67	$10.86	$11.15	$11.46	$11.80	$12.18	$12.59	$13.04	$13.56
Essential: $Cost_{2021}$ = 11,567,207; M_{2021} = 1,132,683; $PRC_{2021} = \$10.21$ per meter per year									
Remaining meters (*m*)	1.13M	1.08M	1.01M	0.94M	0.87M	0.80M	0.73M	0.66M	0.59M
Meter reading cost (*c*)	$11.57M	$11.27M	$10.91M	$10.53M	$10.14M	$9.73M	$9.30M	$8.85M	$8.38M
Unit cost per year (*c / m*)	$10.21	$10.48	$10.83	$11.22	$11.65	$12.14	$12.70	$13.34	$14.09
Evoenergy: $Cost_{2021}$ = 1,029,931; M_{2021} = 168,310; $PRC_{2021} = \$6.12$ per meter per year									
Remaining meters (*m*)	0.17M	0.16M	0.16M	0.15M	0.14M	0.13M	0.12M	0.11M	0.10M
Meter reading cost (*c*)	$1.03M	$1.02M	$0.99M	$0.96M	$0.93M	$0.90M	$0.86M	$0.83M	$0.80M
Unit cost per year (*c / m*)	$6.12	$6.19	$6.37	$6.57	$6.79	$7.02	$7.29	$7.59	$7.92

*Source: FY21 RIN data, Mott MacDonald, HoustonKemp analysis. *FY21 numbers are calculated using RIN data, and are consistent with the dataset used in our top-down analysis.*

Figure A2.1 presents the metering unit cost forecasts from Table A2.1 in graphical form.

Figure A2.1: Metering unit costs using Matt MacDonald approach



Source: FY21 RIN data, Mott MacDonald, HoustonKemp analysis.

A2.2 Frontier Economics approach

Frontier Economics assumes that the unit cost of reading a legacy meter is inversely proportional to the square root of the number of meters installed. This assumption is reflected in the following formula:[44]

$$C = k/\sqrt{N}, \text{ where:}$$

- C is the unit cost of reading a legacy meter;
- N is the number of installed legacy meters; and
- k is a constant.

Note that this differs from the Mott MacDonald approach only by a factor – the Mott Macdonald approach is equivalent to the Frontier Economics approach with constant $k = PRC\sqrt{M}$.

Frontier Economics derives the constant *k* based on 'discussions from Centrica', and it is not clear how this was conducted. We generate *k* estimates for each DNSP by regressing *C* against $\frac{1}{\sqrt{n}}$ without an intercept.[45]

Table A2.2 sets out our estimates of meter reading costs for each DNSP when applying the Frontier Economics approach with these *k* parameters.

Table A2.2: Metering cost estimates using Frontier Economics approach with individual *k* parameters

	FY21*	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Ausgrid: $Cost_{2021}$ = 9,861,755; N_{2021} = 1,942,512; k = 13,054,477,772									
Remaining meters (*n*)	1.94M	1.86M	1.77M	1.67M	1.58M	1.48M	1.39M	1.30M	1.20M
Meter reading cost (*C*)	$9.37M	$9.16M	$8.93M	$8.69M	$8.44M	$8.18M	$7.92M	$7.65M	$7.37M
Unit cost per year (*C / n*)	$4.82	$4.93	$5.06	$5.20	$5.35	$5.52	$5.70	$5.90	$6.13
Endeavour: $Cost_{2021}$ = 13,985,789; N_{2021} = 1,311,084; k = 13,202,846,671									
Remaining meters (*n*)	1.31M	1.27M	1.20M	1.14M	1.07M	1.01M	0.94M	0.88M	0.81M
Meter reading cost (*C*)	$13.99M	$13.74M	$13.39M	$13.02M	$12.64M	$12.25M	$11.85M	$11.44M	$11.17M
Unit cost per year (*C / n*)	$10.67	$10.86	$11.15	$11.46	$11.80	$12.18	$12.59	$13.04	$13.75
Essential: $Cost_{2021}$ = 11,567,207; N_{2021} = 1,132,683; k = 14,035,345,987									
Remaining meters (*n*)	1.13M	1.08M	1.01M	0.94M	0.87M	0.80M	0.73M	0.66M	0.59M
Meter reading cost (*C*)	$11.57M	$11.27M	$10.91M	$10.53M	$10.14M	$9.73M	$9.30M	$8.85M	$7.77M
Unit cost per year (*C / n*)	$10.21	$10.48	$10.83	$11.22	$11.65	$12.14	$12.70	$13.34	$13.06
Evoenergy: $Cost_{2021}$ = 1,029,931; N_{2021} = 168,310; k = 506,261,358									
Remaining meters (*n*)	0.17M	0.16M	0.16M	0.15M	0.14M	0.13M	0.12M	0.11M	0.10M
Meter reading cost (*C*)	$1.23M	$1.22M	$1.18M	$1.15M	$1.11M	$1.08M	$1.04M	$1.00M	$0.95M
Unit cost per year (*C / n*)	$7.33	$7.42	$7.64	$7.87	$8.13	$8.42	$8.73	$9.09	$9.49

*Source: FY21 RIN data, Frontier Economics, HoustonKemp analysis. *FY21 numbers are predicted values from the Frontier Economics approach.*

[44] Frontier Economics, *Smart metering: A report prepared for Centrica*, October 2007, p 42.

[45] We also tested deriving a single *k* estimate across all DNSPs by regressing *C* against $\frac{1}{\sqrt{meter\ density}}$ without an intercept, where *meter density* is the number of meters divided by route length. However, this generated implausibly low cost estimates for Ausgrid and Endeavour.

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