Electricity network performance report

July 2022

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Australian Competition and Consumer Commission
GPO Box 3131
Canberra ACT 2601

or publishing.unit@accc.gov.au

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Tel: 1300 585 165

Email: networkperformancereporting@aer.gov.au

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Contents

1 This network performance report

This is the third annual network performance report for electricity networks. It analyses key outcomes and trends in the operational and financial performance data we collect from electricity distribution and transmission network service providers (DNSPs and TNSPs, or collectively, NSPs). Since 2021, we have prepared similar reports for fully regulated gas pipelines.

Our network performance reports aim to be accessible information resources that improve transparency and accountability around how NSPs are performing under the regulatory regime, thereby encouraging improved performance. Analysing network performance against forecasts helps us and others to understand the effectiveness of the regulatory regime; thereby supporting informed engagement, data-driven debate, and continuous improvement.

The key findings for 2021 are that:

- Network revenue is continuing its trend downwards since 2015 and is about 5.6 per cent lower than in 2020. Despite this, NSPs continue to be profitable and generate returns above our forecasts despite the continued impacts of COVID–19. This reflects a range of different drivers, including financing strategies and spending less than our forecasts across different revenue building blocks.
- Regulatory asset base (RAB) per customer increased marginally since 2020, after having been on a consistent, steady decline since 2016. In 2021, there was 2.1% growth in transmission network RABs, which had otherwise declined since 2014. We expect transmission RABs to continue growing as several major projects are being developed.
- Outages were both fewer and shorter on average than in 2020. This includes both normalised outages (that is, unplanned outages less excluded events such as major event days), as well as the total outages that customers experienced.
- The average normalised customer interruption time decreased, which differs from its upwards trend since 2011. This may reflect changes made to the service target performance incentive scheme (STPIS) that started taking effect from 2020, although further analysis of the data is needed before we can draw conclusions about this relationship.
- Maximum demand (MVA) per customer reached a record low since we started measuring it in 2006. This has several potential drivers, including greater use of solar photovoltaics and improved energy efficiency.
- Reduced maximum demand contributed to the decrease in average distribution network utilisation from 44 per cent in 2020 to 41 per cent. This contrasts to the trend of gradually increasing utilisation since 2015.
- The rollout of smart meters outside Victoria and network tariff reform have been progressing slowly. While smart meters are required to enable cost reflective tariffs, they are not sufficient (which low adoption of cost reflective tariffs in Victoria shows). While penetration of cost reflective tariffs is low, there is evidence that some load switching away from peak times has occurred over the last few years.

- Significant outages have been occurring when extreme events occur. NSPs have been finding it harder to manage the risks associated with extreme events through insurance and self-insurance, with a total $334.6 million being passed onto consumers since 2014 through natural disaster pass throughs.

Our analysis focuses on core regulated services, which are the main energy transport services NSPs provide with the network assets in their RABs.[1] These services are called:

- Standard control services for electricity DNSPs
- Prescribed transmission services for electricity TNSPs.

An effective network regulatory regime contributes to consumers paying no more than is necessary for a safe and secure supply of energy. Implicit in this vision is a balance between the costs of providing network services and the outcomes arising from those costs. We have structured the report to systematically consider whether this balance is being achieved, linking back to our performance reporting priorities (summarised in Appendix B).

In our view, our electricity network performance reports to date show that network regulation is improving outcomes for consumers. This report, like reports in previous years, highlights the impact of improvements in our regulatory tools over recent years, but also highlights areas for further work. We encourage stakeholders to read this report alongside our annual benchmarking report, which reports on NSPs' productive efficiency.[2]

1.1 Focus areas

Our network performance reports balance regular high-level reporting on a core set of measures with more detailed analysis on focus areas representing emerging issues of stakeholder interest. Our focus areas in 2022 are:

- The progress and impacts of tariff reform to date (section 5)
- The impact of extreme events on reliability, insurance, and network expenditure (section 6).

In addition to these focus areas, section 7 continues our network safety reporting work that we commenced in 2021, where we said we would continue summarising data from jurisdictional regulators, and potentially develop our own dataset in the future.

We also consulted on whether to report on the drivers and impacts of NSPs' unregulated revenue.[3] We considered this could be valuable given some factors affect RAB multiples that are not direct outcomes of the regulatory regime or the NSPs' core regulated services, and these include unregulated revenue. However, Cambridge Economic Policy Associates (CEPA) have

1 While NSPs also provide and collect network revenue for other services, these sit outside the revenue cap and can be subject to other forms of regulation or, in some cases, unregulated.

2 Found under AER, *Guidelines, schemes, models & reviews*, accessed 2 April 2022.

3 We identified 'better understanding the impact of unregulated network activities on financial performance indicators' as a potential focus area for 2022 in AER, *Electricity network performance report*, 2021.

already been investigating this relationship as part of our 2022 rate of return instrument review.[4] Given the AER is already considering this analysis in a different forum, and given stakeholders expressed greater interest in other focus areas, we have not explored the drivers and impacts unregulated revenue as a focus area this year.

In developing this report, we engaged with stakeholders to test views on focus areas. We aim to choose new and relevant focus areas each year to reflect important emerging issues and stakeholder interest. To best target those choices, we encourage direct feedback on future topics or emerging issues of interest. Section 8 identifies some potential focus areas for future reports.

1.2 Stakeholder engagement on the report

Before we developed our first network performance report, we undertook extensive stakeholder engagement to:

- Develop priorities and objectives for reporting on network performance[5], also set out in Appendix B.
- Complete our profitability measures review, which has been an important input into our network performance reports.[6]

In developing this report, we:

- Sought early input from a cross-section of consumer and industry stakeholders on focus areas to explore in this report.
- Gave NSPs an opportunity to review the accuracy of our key data sources.
- Gave NSPs, consumer representatives and other relevant stakeholders an opportunity to review and engage with our analysis.
- Engaged with state and territory safety and technical regulators on the accuracy of the safety analysis within the report.

4 CEPA, *EV/RAB multiples*, 10 May 2022.

5 AER, *Objectives and priorities for reporting on regulated electricity and gas network performance 2020*, 2020.

6 AER, *Profitability measures for electricity and gas businesses*, 2019.

2 Context for this year's report

This network performance report covers network data for regulatory year 2021, which is:

- July 2020–June 2021 for financial year NSPs (all except Victoria)
- April 2020–March 2021 for AusNet (transmission) (Victoria)
- January 2021–June 2021 for Victorian DNSPs[7]

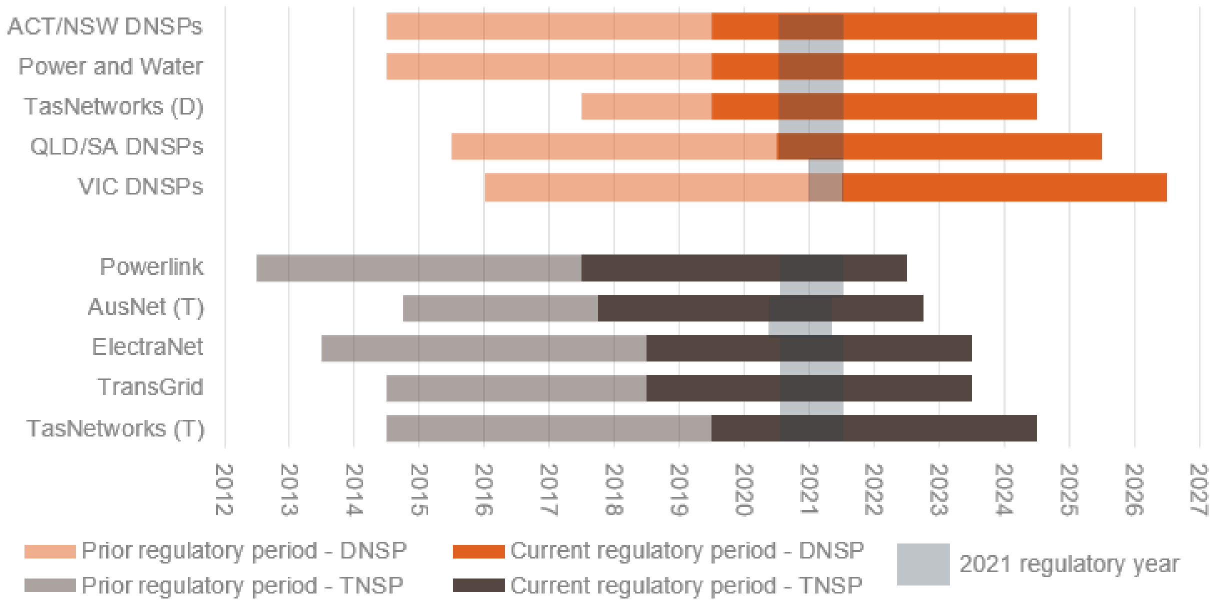
On certain topics and where stated, we include some information after these dates. This is to provide greater context to stakeholders and does not form part of our core reporting measures.

The Victorian government legislated a six-month extension to its previous regulatory determination for the Victorian DNSPs – AusNet (distribution), CitiPower, Jemena Electricity, Powercor Australia and United Energy. The 2021 regulatory year was therefore six months for these DNSPs. To compare against prior regulatory years and forecasts, we have reported the 2021 regulatory year using annualised data from this six-month period.

2.1 Where 2021 sits in the regulatory cycle

Generally, our regulatory determinations apply over five years. We also make these determinations in a staggered cycle. Due to this, changes in regulatory approaches or market conditions affect NSPs gradually.

Figure 2-1 The staggered revenue decision timetable



Source: AER analysis.

7 The Victorian Government legislated a six-month extension its previous regulatory determination to finish on 30 June 2021. Due to this, the 2021 regulatory year was only for a six-month period. This next full five year regulatory period for Victorian DNSPs commenced on 1 July 2021.

For convenience, we think of regulatory cycles as commencing with determinations for the DNSPs in NSW, ACT, Tasmania, and the Northern Territory. These determinations affect a notable proportion of regulated NSPs and have historically been the first major decisions to incorporate substantial changes in regulatory settings (for example, 2013 better regulation reforms and the 2018 rate of return instrument).

2.2 Reporting on Northern Territory Power and Water Corporation

In 2019, we made our first determination for Power and Water Corporation (Power and Water), the Northern Territory's DNSP. Regulatory year 2021 is the second year of its first regulatory control period under an AER determination. Unless otherwise specified in the report, we have included Power and Water data in our report. Where the relevant data series is relatively simple—for example historical RAB trends—we have included historical Power and Water data in our existing data series for continuity.

3 Summary of operational performance in 2021

This section looks at the following core performance outcomes:

- network revenue—the cost to consumers of network services (section 3.1)
- network expenditure (section 3.2)
- RAB size over time (section 3.3)
- network service outputs related to reliability (section 3.4)
- distribution network utilisation (section 3.5).

Unless otherwise stated, all values are presented in real 2021 dollar terms to enable comparisons over time.

We also focus on:

- how outcomes in 2021 relate to longer term trends across network performance measures
- where relevant, how those outcomes compare to forecast amounts.

This section does not directly investigate whether the relationships between network expenditure and service outputs are productively efficient. Rather, our benchmarking reports directly measure how productively efficient NSPs are at delivering core regulated services over time and compared with their peers. Our next benchmarking report will be published later this year.[8]

This report more directly explores the costs and profitability of providing core regulated services, which are consequences of NSPs' productive efficiency, capital market conditions and our regulatory settings. Regulatory settings include how we forecast expenditure and share the rewards or penalties of network performance between NSPs and consumers.

3.1 Network revenue—the cost to consumers of network services

The total revenue NSPs recover is an informative measure of how core network services are contributing to consumers' bills, even though it is complex to make general observations about the impact of network costs on specific consumer bills. One complexity is that the proportion of total revenue collected from different types of consumers varies between NSPs and over time. Another complexity is that most electricity consumers pay network costs via a retailer, where they are combined with other costs of supplying energy.

In addition to recovering the costs of core network services, DNSPs must also collect other costs from consumers, such as the costs of jurisdictional schemes, which we do not have a role in setting. Some of these schemes, such as jurisdictional solar bonus schemes, are not included in the revenue building blocks. For this section, 'network costs' refers only to costs arising from:

- DNSPs providing standard control services, and

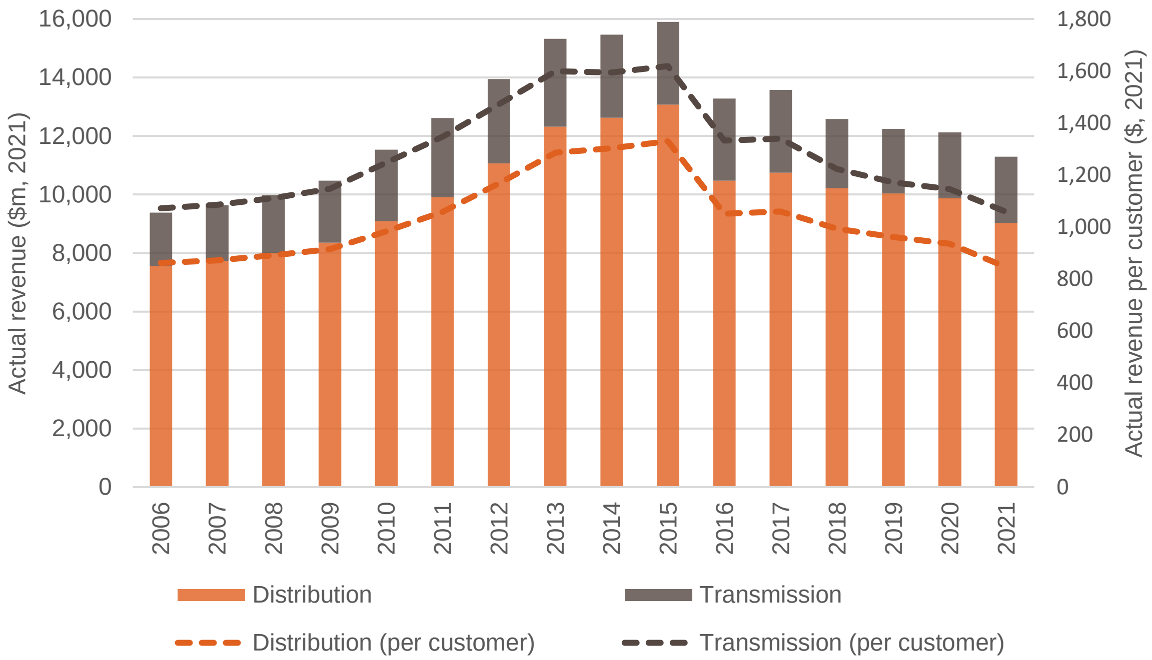
8 Our previous benchmarking report is available at AER, *Annual benchmarking reports 2021*, November 2021.

- TNSPs providing prescribed transmission services

3.1.1 Actual network revenue

In 2021, NSPs charged customers in total less for electricity network services than they have at any time since 2010 (
Figure 3-1).

Figure 3-1 Total core regulated network service revenue recovered from consumers - DNSPs and TNSPs



Source: Operational performance data, AER analysis.

Note: These are the total actual standard control service and prescribed transmission service revenue amounts collected from consumers, as opposed to annual target revenue, the smoothed post tax revenue model (PTRM) revenue target or the unsmoothed building block revenue total.

The downward trend in network revenue means that consumers are paying less for the network component of their bills on average. Growth in customer numbers also amplifies this effect on an individual customer basis. Consumers' bills are also made up of several other components, including wholesale market costs, retail margins and jurisdictional costs. Further information on these other bill components is set out in our State of the Energy Market report[9], and in our regular wholesale and retail reporting.[10]

9 All versions of State of the energy market are available at AER, *State of the energy market reports*, accessed 11 April 2022.

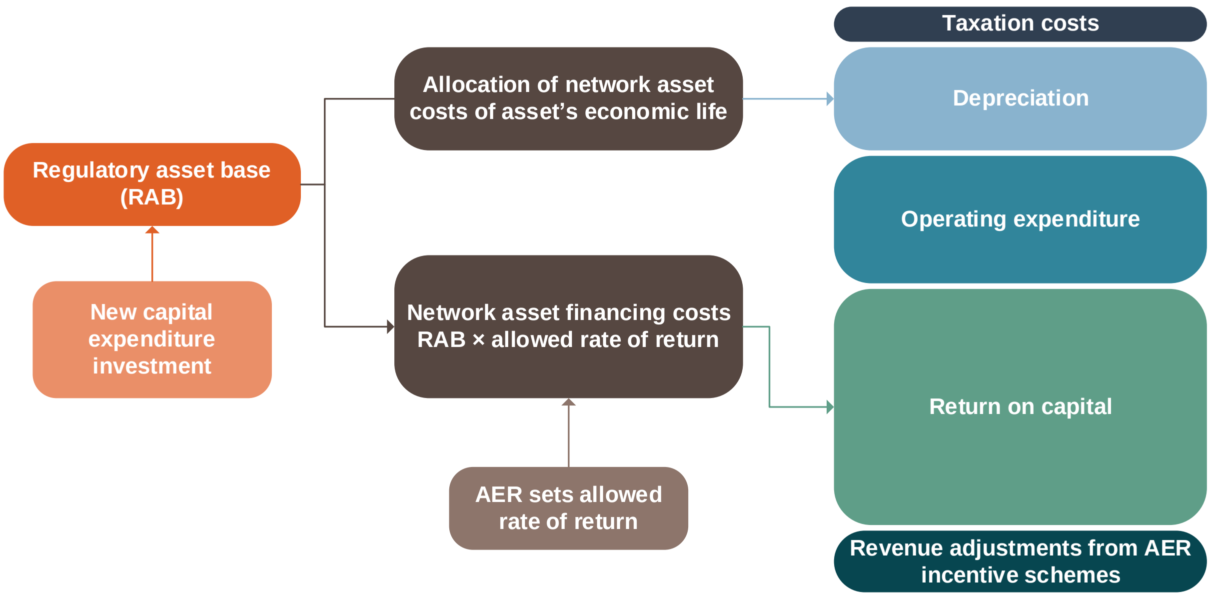
10 AER, *Performance reporting (wholesale markets)*, accessed 3 June 2022; AER, *Performance reporting (retail markets)*, accessed 3 June 2022.

3.1.2 Drivers of network revenue

All electricity NSPs are now regulated under revenue caps.[11] NSPs annually set their prices to target earning the maximum revenue allowed under the revenue cap. We set the maximum allowed revenue so NSPs can recover the costs of an efficient network providing core regulated services. These are determined as ‘building blocks’, and include:

- A return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in the NSP).
- Depreciation of the RAB (or return of capital, to return the initial investment to investors over time).
- Forecast capital expenditure (capex) incurred in providing network services, which then enters the RAB and depreciated over the economic life of the asset.
- Forecast operating, maintenance and other non-capital expenses (opex) incurred providing network services.
- The estimated cost of corporate income tax.
- Revenue adjustments, including revenue increments or decrements resulting from applying incentive schemes.

Figure 3-2 The building block model to forecast network revenue



Source: AER analysis, adapted from AER, *State of the Energy Market*, December 2018, p.138.

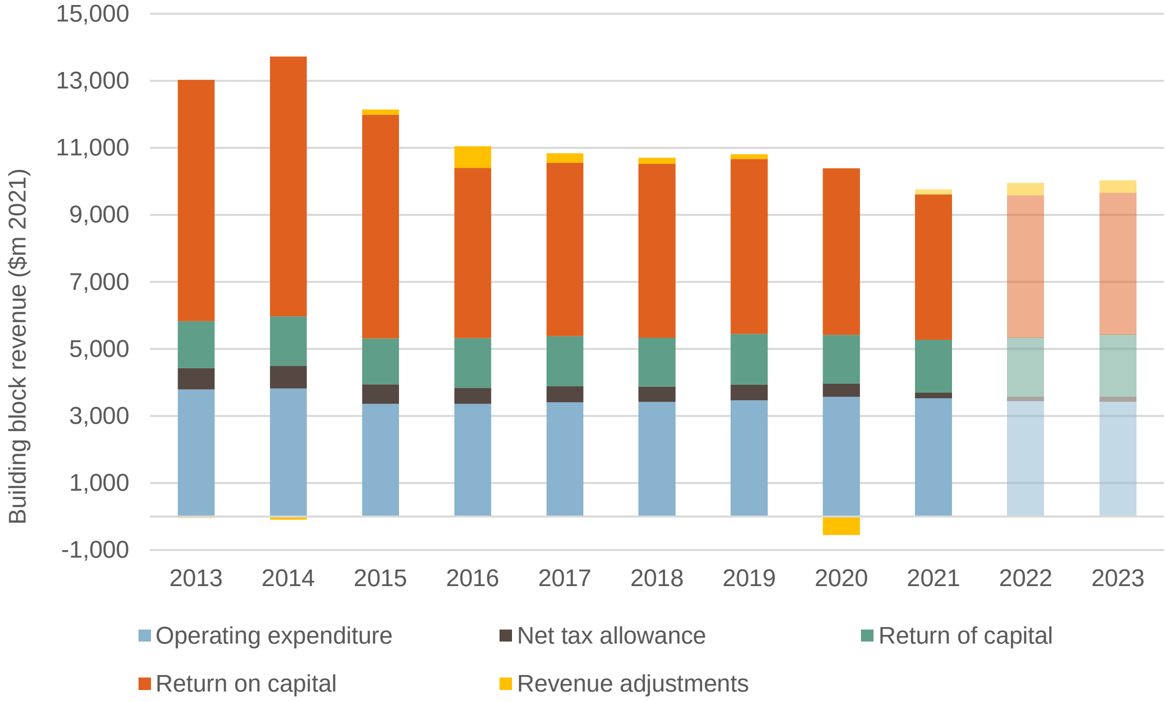
We also update the revenue target each year to account for actual inflation, changes in the NSP’s required returns on debt, cost pass throughs and other factors.

11 The last network to be moved to a revenue cap was Evoenergy at the commencement of its 2019–24 regulatory control period.

In 2021, forecast network revenue continued to decline, driven largely by declining forecast returns on capital (Figure 3-3).

The forecasts in Figure 3-3 suggest NSP network revenue will stay approximately around its 2021 level in 2022 and 2023. The impacts of the 2018 rate of return instrument and 2019 tax review have been feeding into lower forecast return on capital and tax building blocks over the last few years.[12] Prevailing interest rates in debt markets also affect revenue allowances through our annual updates to the return on debt.

Figure 3-3 Trends in forecast building block revenue components — DNSPs and TNSPs



Source: PTRMs, AER analysis

3.1.3 Incentive Schemes

We apply an incentive-based regulatory regime where we incentivise NSPs to outperform our revenue allowances by ensuring they keep a share of their profits or losses. In addition, we also apply targeted incentive schemes that encourage desirable behaviours from the NSPs (namely to improve efficiency and reliability), thereby delivering better outcomes for consumers.[13] To date, NSPs have received rewards or penalties under the following incentive schemes:

- efficiency benefit sharing scheme (EBSS)

12 The impact of allowed rates of return on NSPs was discussed in detail in AER, *2020 electricity network performance report*, 2020.

13 The revenue impact of incentive schemes was a focus area in AER, *2020 electricity network performance report*, 2020.

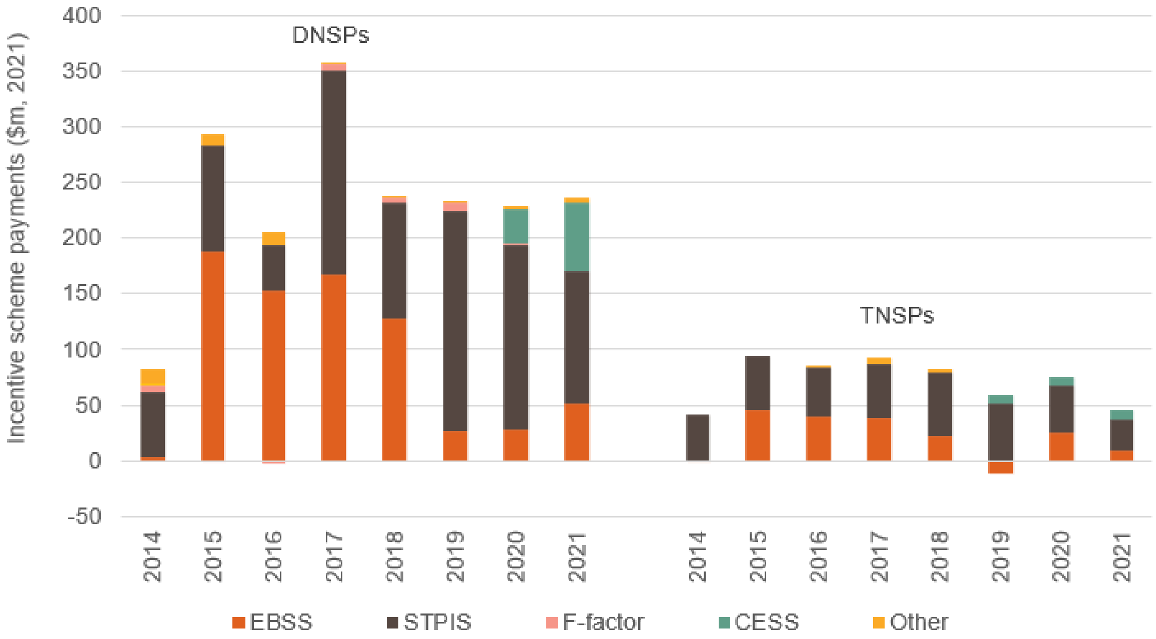
- STPIS
- demand management incentive scheme (DMIS) for the DNSPs
- F-factor scheme for the Victorian DNSPs[14]
- capital expenditure sharing scheme (CESS)

We are currently undertaking a review of our incentive schemes and guidelines to ensure they remain relevant and fit-for-purpose.[15]

In 2021:

- Victorian DNSPs only received payments from the DMIS. The EBSS, STPIS, F-factor and CESS did not apply to the six month extension of their regulatory control period.
- Despite the lack of payments available to the Victorian DNSPs, overall, DNSPs received more in incentive scheme payments than 2020, but TNSPs received less.
- Most incentive scheme payments were from the STPIS.
- Both DNSPs and TNSPs are beginning to report payments under the CESS. These CESS amounts are likely to increase as more NSPs enter new regulatory control periods.

Figure 3-4 Composition of reported incentive scheme payments



Source: Economic benchmarking RIN responses, Post Tax Revenue Model and AER analysis.[16]

14 The Victorian Government introduced the 'f-factor scheme' on 23 June 2011, which incentivises DNSPs to reduce the risk of fire starts and the loss or damage they cause. This incentive scheme was implemented following the 2009 Black Saturday bushfires.

15 AER, [Review of incentive schemes for regulated networks](), Accessed 20 April 2022.

16 Other includes incentive payments in relation to the demand management incentive allowance, DMIS and total shared asset adjustments.

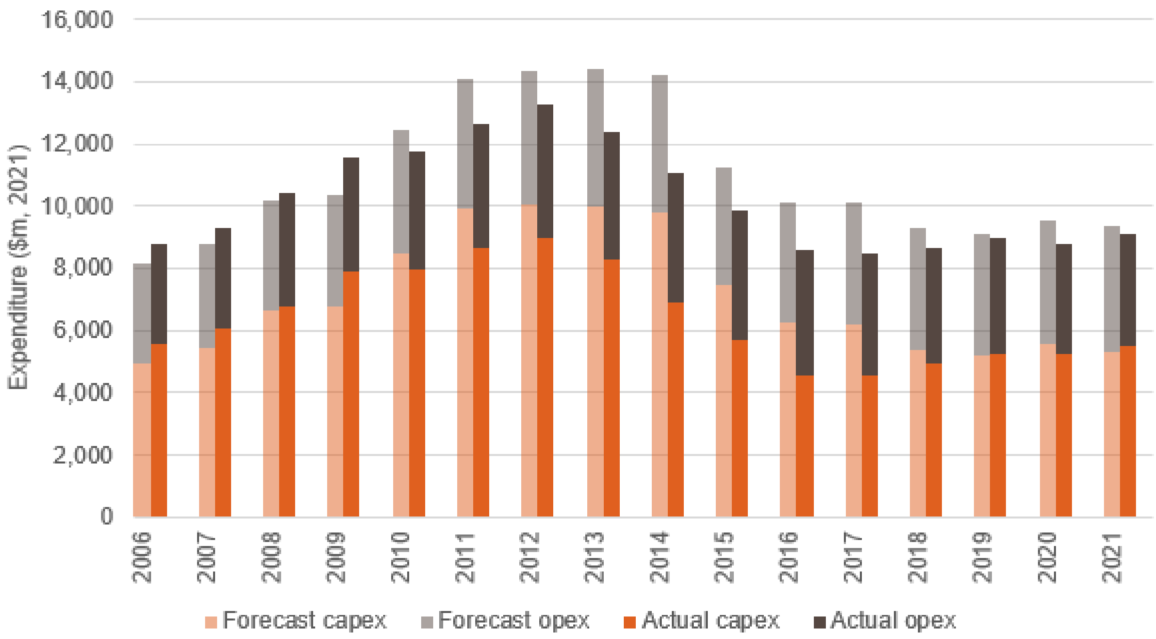
3.2 Network expenditure

Under the regulatory regime, we regulate revenue and not expenditure. As such, NSPs can generally spend the network revenue they collect from consumers however they determine to be most efficient in providing a safe and reliable supply of electricity.

In 2021:

- NSPs overall spent marginally more opex and capex than they did in 2020.
- Expenditure increases were lower than what was forecast overall but were higher than what was forecast for capex.

Figure 3-5 Total Expenditure - DNSPs and TNSPs



Source: Operational performance data, AER analysis

Expenditure outcomes in specific NSPs discussed below materially affect these overall outcomes.

3.2.1 Increased transmission capex in NSW

Aggregate expenditure in 2021 is influenced by increased forecast and actual transmission capex in NSW:

- TransGrid's forecast capex increased $253 million on 2020 levels (a 67% increase). The combined forecast change for all other TNSPs was a $13 million decrease.

- TransGrid's actual capex increased $455 million on 2020 levels (a 138% increase). The change in actual capex for all other TNSPs was a $22 million increase.

The increase in TransGrid's forecast capex is largely in connection with major transmission projects, for which it received an allowance through the contingent project process. This includes an increased capex allowance in 2021 to deliver Project EnergyConnect (about $276 million), the Queensland-NSW Interconnector minor upgrade (about $115 million) and the Victoria–NSW Interconnector minor upgrade (about $15 million).[17]

While increased capex associated with major transmission projects is more prevalent in NSW, major transmission investment is occurring across the National Electricity Market (NEM). We expect this pattern to continue as more major transmission projects within the Integrated System Plan's optimal development path are commissioned.[18]

3.2.2 Victorian DNSP expenditure underspends

Victorian DNSPs' opex underspends, which were notably higher than their capex overspends, had a sizeable effect on aggregate expenditure in 2021. When comparing actual opex in 2021 against forecast opex:

- the Victorian DNSPs spent a combined $198 million (21%) less than forecast opex in 2021.
- All other DNSPs together spent a combined $132 million (6%) less than forecast opex in 2021.

The Victorian DNSPs' 2021 regulatory year was a six-month transitional period from their previous regulatory control period before their 2021–2026 regulatory control period, which was calculated based off rolling the 2020 regulatory year forward. The 2021 regulatory year therefore has unusual characteristics for Victorian DNSPs, although it is hard to be definitive about its overall effect. While some evidence suggests expenditure incentives are not always even throughout regulatory control periods (despite their intended design), it is not clear if this is affecting these results. We also recognise various network-specific factors can affect expenditure each year and we are exploring whether expenditure incentives are balanced in our review of incentive schemes.[19]

3.2.3 Ergon Energy capex overspends

Ergon Energy spent $254 million more capex than forecast for 2021, after having already spent $190 million more than forecast in 2020. It is worth noting that 2020 was the final year of Ergon Energy's previous regulatory control period, which, due to capex underspends in previous years, still resulted in Ergon Energy having a total $81 million capex underspend over period.

17 Figures adjusted from $ 2017–18 to $ 2020–21 as found in AER, *Final decision - TransGrid contingent project - QNI minor upgrade*, 2020 Table 4; AER, *Final decision - TransGrid contingent project - Project EnergyConnect*, 2021, Table 3; AER, *Final decision - TransGrid contingent project - VNI minor upgrade*, 2021, Table 4.

18 For projects proposed for the optimal development path, see AEMO, *2022 Draft Integrated System Plan (ISP)*, accessed 19 April 2022.

19 AER, *Review of incentive schemes for regulated networks*, accessed 22 June 2022.

The $254 million capex overspend in 2021 equates to 54 per cent of Ergon Energy's forecast capex for that year. This has a material impact on the aggregate expenditure shown in Figure 3-5, resulting in a total capex underspend amongst DNSPs being $203 million rather than $51 million overspend. Section 8.2.2 of the 2020-21 annual reporting RIN explains material differences between forecast and actual capex; with $254 million overspend due to asset replacement capex.[20]

Apart from Endeavour Energy overspending its 2021 capex allowance by $4 million, all other DNSPs underspent their capex allowances in 2021.

3.2.4 Second year of Power and Water's expenditure outcomes

Power and Water has now been regulated under an AER determination for two years. In 2021, we observe Power and Water spent approximately:

- $24 million (25%) less capex than forecast, after having spent $23 million (34%) less than forecast in 2020.
- $10 million (15%) more opex than forecast, after having spent $21m (30%) more than forecast in 2020.

We will continue to monitor Power and Water's expenditure outcomes in future years to monitor whether this pattern persists and, if so, understand its implications.

3.3 Regulatory asset bases

RABs capture the total economic value of network assets that NSPs use to provide regulated network services. Over time, the RAB grows as NSPs undertake capex. RAB values substantially affect NSPs' revenue requirements, and the total costs consumers ultimately pay. This is because consumers pay the costs of raising capital through the return on capital (calculated by applying the allowed rate of return to the RAB) and return of capital (depreciation) allowances. We also inflate the RAB each year to reflect the impacts of inflation. This increases the nominal value of the assets to maintain their real value through time.[21]

Network assets in the RAB have been accumulated over time and will be at various stages of their economic lives. Some NSPs' average asset lives may be relatively old or young depending on their growth and their phase of the replacement cycle.

20 AER, *Ergon Energy network information – RIN responses*, accessed 13 June 2022. Section 8.2.2 of the 2020-21 annual reporting RIN explains material differences between forecast and actual capex

21 The indexation of the RAB is explained on our website here.

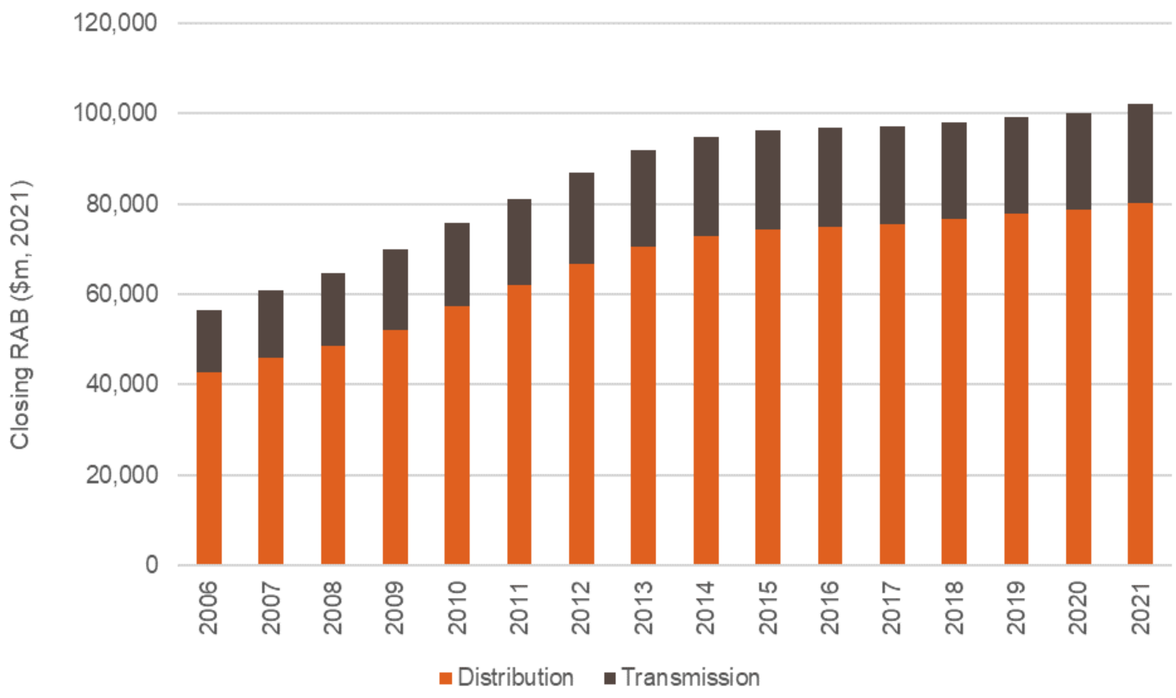
3.3.1 Total RAB growth

In 2021:

- The total real value of RABs increased on 2020 by 1.2%. This broadly aligns with recent gradual RAB growth but is on the upper end of growth rates since 2014.
- This is the combination of:
  - 1.0% growth in distribution network RABs
  - 2.1% growth in transmission network RABs, which have previously been declining since 2014. We expect growth in transmission network RABs to continue as several major transmission projects are under development.
- Annual aggregate real RAB growth has been approximately 1% per year since 2015, compared to approximately 7% per year over 2008–14.

As Figure 3-6 shows, in recent years, RAB growth has been lower than in previous regulatory control periods, which was largely driven by lower capex. Although there has been a material reduction in actual capex since 2014, depreciation since 2014 has remained relatively steady. This is because of the cumulative impact of historical investments and the straight-line depreciation approach we use, which returns capital evenly over the life of an asset. As a result, real RAB growth has slowed. In the case of some TNSPs, RABs have recently declined in real terms.

Figure 3-6 RAB values - DNSPs and TNSPs

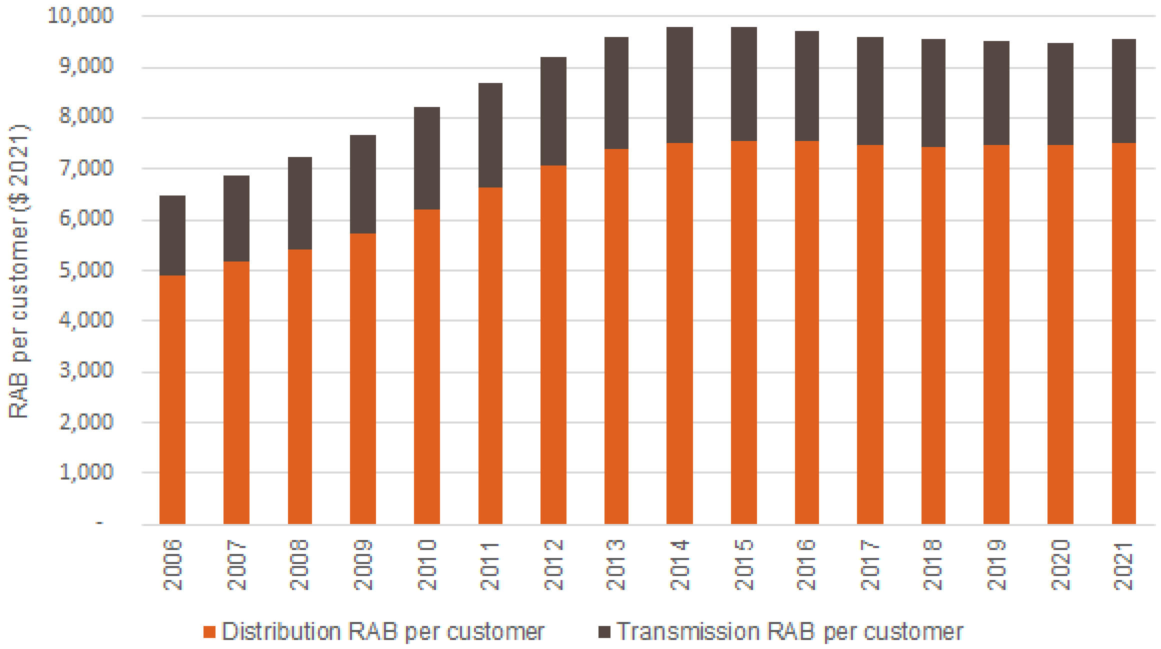


Source: Operational performance data, AER analysis.

3.3.2 RAB per consumer

Growing RABs do not necessarily result in growing capital costs per consumer if either the rate of return is declining, or the consumer base is growing. Both are currently the case.

Figure 3-7 RAB per customer - DNSPs and TNSPs



Source: Operational performance data, AER analysis.

Over 2015 to 2020, consumer numbers grew faster than real RABs, resulting in a levelling and occasionally declining average RAB per customer. In 2021, RAB per customer increased.

3.4 Network reliability

A key network service output is to have a reasonably reliable supply of electricity. In this context, reliability refers to the continuity of electricity supply and is typically measured by the frequency and duration of interruptions to supply. 'Reasonably' reliable recognises there is a trade-off between reliability and affordability as maintaining or improving reliability may require expensive investment in network assets. Reliability standards and incentive schemes therefore try target reliability levels for which most consumers are willing to pay.

We collect and report data on reliability and utilisation for both DNSPs and TNSPs. For this report, we have focussed our analysis on DNSPs, recognising that most supply interruptions originate at the distribution level. Through our reporting over time, we will capture a balance of distribution and transmission network service outcomes.

We report on both:

- The frequency and duration of unplanned outages, which we determine under our STPIS to be within the NSP's control at their funding levels. This will exclude some outages, including some major events that are part of the total unplanned outages. We refer to these as 'normalised' measures of reliability:

- System Average Interruption Frequency Index (SAIFI) measures the average number of interruptions each year outside of excluded events.
- System Average Interruption Duration Index (SAIDI) measures the average duration (minutes) of interruptions each year outside of excluded events.

- Unplanned outages excluded from SAIDI and SAIFI include major events such as storms, fires, floods, and cyclones. Detailed analysis on the impact of major events and how these are changing over time is provided in section 6.

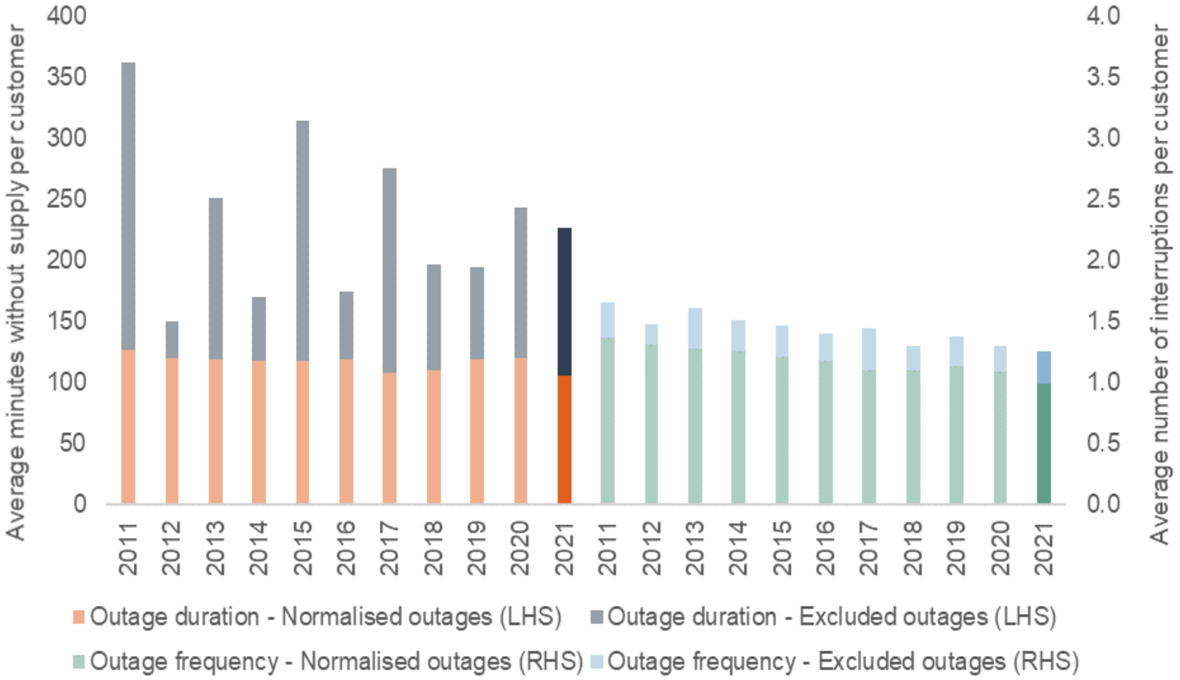
These indices, combined with excluded outages, allow us to evaluate the total frequency and duration of unplanned outages experienced by distribution network consumers. We refer to these as 'total unplanned outages'. Considering these measures together allows us to form a more comprehensive picture of unplanned outages experienced by consumers.

3.4.1 SAIDI and SAIFI

In 2021:

- The average duration of normalised distribution outages (measured by SAIDI) decreased slightly against 2020, however this varies between NSPs and varies considerably annually. As such, little can be inferred from movements in annual data.
- Average normalised frequency (measured by SAIFI) is continuing its downwards trend. While SAIFI is currently the lowest it has been at any time in our data series, this may partly be influenced by a new measurement approach that we have been transitioning towards.

Figure 3-8 Unplanned outages - DNSPs



Source: Operational performance data, Economic Benchmarking RIN, AER analysis.

Over the longer time series, we observe that:

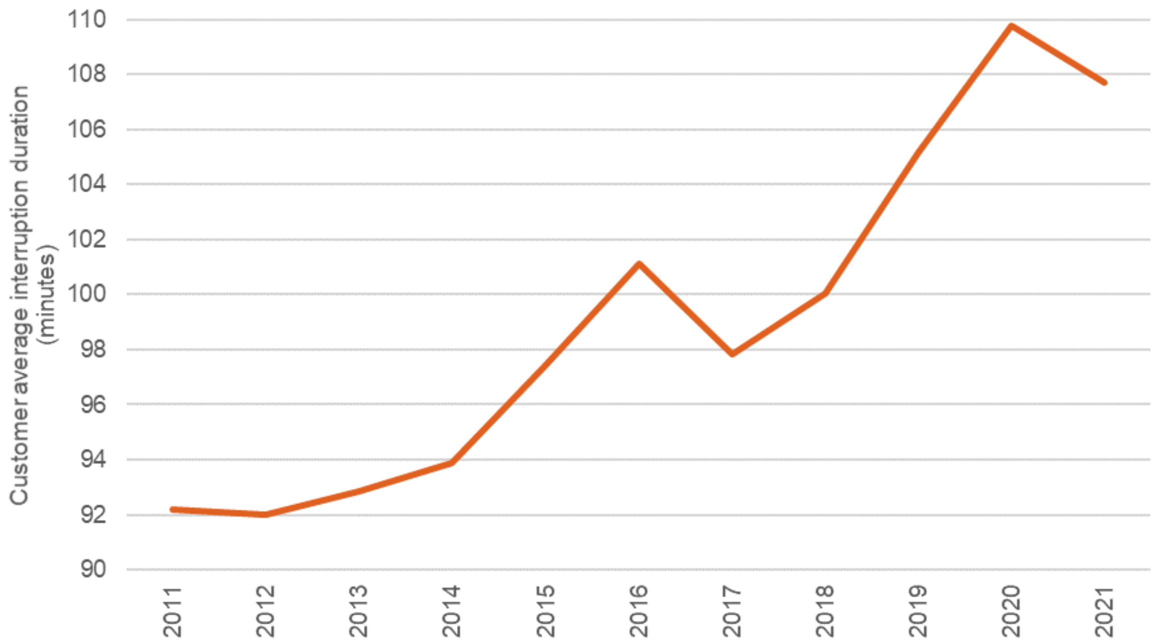
- Consumers have experienced fewer distribution network outages, which is evident in both SAIFI and when accounting for excluded unplanned outages. While there has been a trend of gradual improvement in normalised SAIFI, this may partly be influenced by a new measurement approach where the threshold for an 'interruption' has increased from one to three minutes.[22] We do not expect the new measurement approach would have a material impact. Reduced SAIFI from the new approach would result in a corresponding increase in the momentary average interruption frequency index (MAIFI), which remains low. However, we will monitor this relationship and seek to adjust historical SAIFI data in future reports so stakeholders can make like-for-like comparisons.
- The average duration of normalised outages (SAIDI), while currently low, shows less of a consistent trend since 2011—although it had been steadily increasing over 2017 to 2020. There is also notable variability in excluded outages. In some years, high impact supply interruptions have resulted in a material difference between normalised reliability and the duration of total unplanned outages.

Comparing the impact of excluded events on the frequency and duration of outages shows that we are excluding relatively few events, but these can have a substantial impact on the average duration of outages that consumers experience. This is consistent with the impact of major events, such as the Queensland floods, Victorian bushfires, the South Australian black system event, and the summer 2019/20 bushfires.

22 We established the new threshold in AER, *Electricity DNSPs: STPIS version 2.0*, November 2018, p. 25, which has been gradually taking effect as STPIS 2.0 is applied to new regulatory control periods – the NSW, ACT and NT DNSPs since the 2020 regulatory year end, and the SA and QLD DNSPs since the 2021 regulatory year end.

In 2021, the duration of normalised customer interruptions decreased relative to their frequency, such that the average normalised customer interruption time decreased. This differs from the broad trend since 2011 of there being a relative decline in SAIFI compared to SAIDI, meaning fewer normalised outages that are longer on average.

Figure 3-9 Relationship between normalised frequency and duration of interruptions - DNSPs



Source: Operational performance data, AER analysis.

NSPs are provided incentives under the STPIS to reduce normalised SAIDI and SAIFI. Historically these incentives have been set with roughly equal weight. This weighting appears to have contributed to a network preference for improvements in SAIFI over SAIDI. In 2018, we updated the STPIS incentive weights to 40% for SAIFI and 60% for SAIDI, with the expectation that this would reduce the apparent incentive for NSPs to prioritise improvements in SAIFI over SAIDI. Further detail on this is set out in our review of the STPIS.[23]

The updated STPIS incentive weights will be applied to each NSP depending on the timing of their regulatory determination. STPIS updates were applied in 2020 to NSPs in NSWs, ACT and Tasmania, and in 2021 to NSPs in Queensland and South Australia. Updates to Victorian DNSPs will be applied in the following year. Data in 2021 may indicate that this re-weighting has started to have an impact, although further data would be needed before we could draw this conclusion, particularly as SAIFI reductions could have also been influenced by the increased ‘interruption’ threshold. As such, we will continue to monitor the relationship between frequency and duration of outages over time.

23 AER, *Explanatory statement: Final decision— Amendment to the Service Target Performance Incentive Scheme (STPIS); Establishing a new Distribution Reliability Measures Guideline (DRMG)*, November 2018.

3.4.2 Different reliability across feeder types

Presenting reliability as an average annual NEM data series may not represent the severity of reliability impacts on affected consumers. This is because consumers on different networks experience different levels of reliability and major events often affect a specific jurisdiction or network.

In previous electricity network performance reports, we illustrated how consumers on different networks experience different levels of reliability.[24] Consumers can also experience different levels of reliability depending on where they are located within a network.

What are the feeder types?

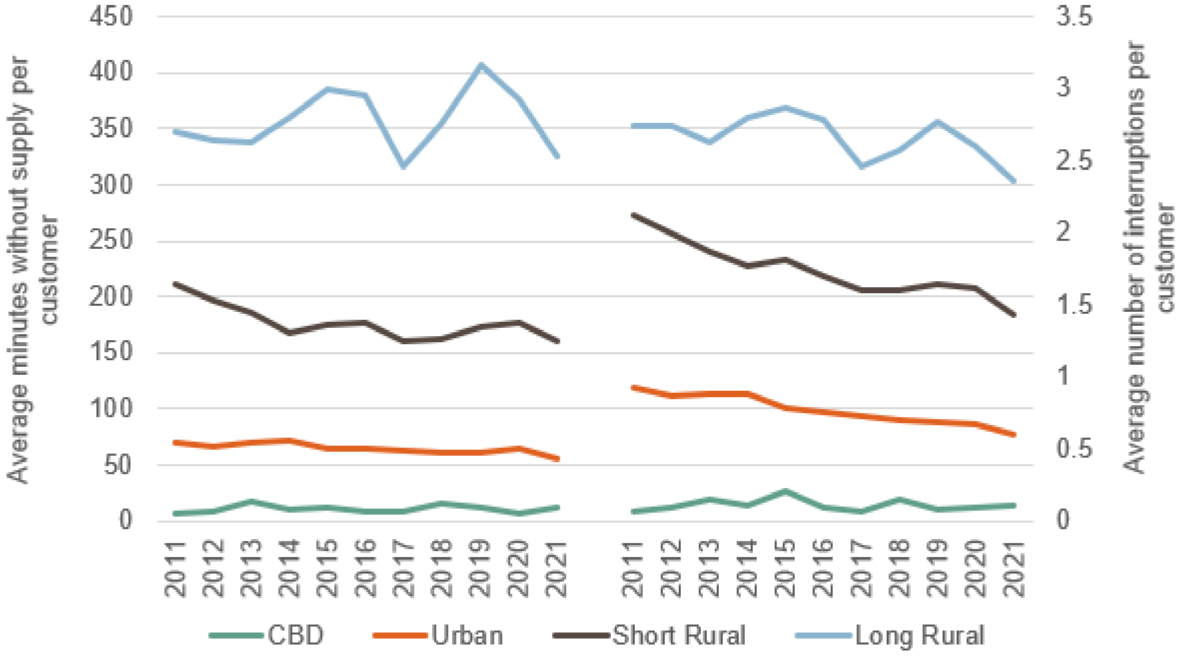
Customers are divided into four feeder types.

- CBD – a feeder in one or more geographic areas that the relevant participating jurisdiction has determined as supplying electricity to predominantly commercial, high-rise buildings. These feeders are supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas.
- Urban – a feeder that is not a CBD feeder and has a maximum demand over the feeder route length greater than 0.3 MVA/km.
- Rural short – a feeder with a total feeder route length less than 200km that is not a CBD or urban feeder.
- Rural long – a feeder with a total feeder route length greater than 200km that is not a CBD or urban feeder.

Figure 3-10 shows that on average, normalised interruptions on rural feeders are longer and more frequent than on CBD or urban feeders.

24 AER, *Electricity network performance report 2021*, September 2021, pp. 50–54; AER, *Electricity network performance report 2020*, September 2020, pp. 34–35

Figure 3-10 Different levels of normalised reliability by feeder type - DNSPs



Source: Operational performance data, AER analysis.

The longer and more frequent normalised interruptions on rural feeders is likely driven by several factors, including, but not limited to:

- different network topology
- the lower likelihood of having in-built redundancy to maintain service when there is a fault, given these costs are particularly high per consumer on longer feeder types
- increased response time relative to line length.

Figure 3-10 also shows different trends in normalised reliability over time:

- There are fewer normalised outages on CBD feeders than on any other feeder type, and this has remained stable over time.
- There have been improvements in the duration and frequency of normalised outages on urban and short rural feeders.
- The frequency and duration of normalised outages have varied on long rural feeders, although the frequency of outages has been trending downwards since 2011.

3.5 Distribution network utilisation

Network utilisation measures the extent to which an NSP's network assets are being used to meet maximum demand. We measure network utilisation for DNSPs as the ratio of reported non-coincident maximum demand (MVA) to total zone substation transformer capacity (MVA). Non-coincident maximum demand across the network adds up load at geographic points (connection points or some other spatial level) when each geographic point experienced maximum demand. This differs from network coincident maximum demand, which measures demand across whole network when it was at its highest.

Given our measurement approach, lower non-coincident maximum demand or higher zone substation transformer capacity would have a downwards impact on distribution network utilisation— both of which occurred over the last year, although these movements were small. Figure 3-11 shows how these three measures have changed since 2006.

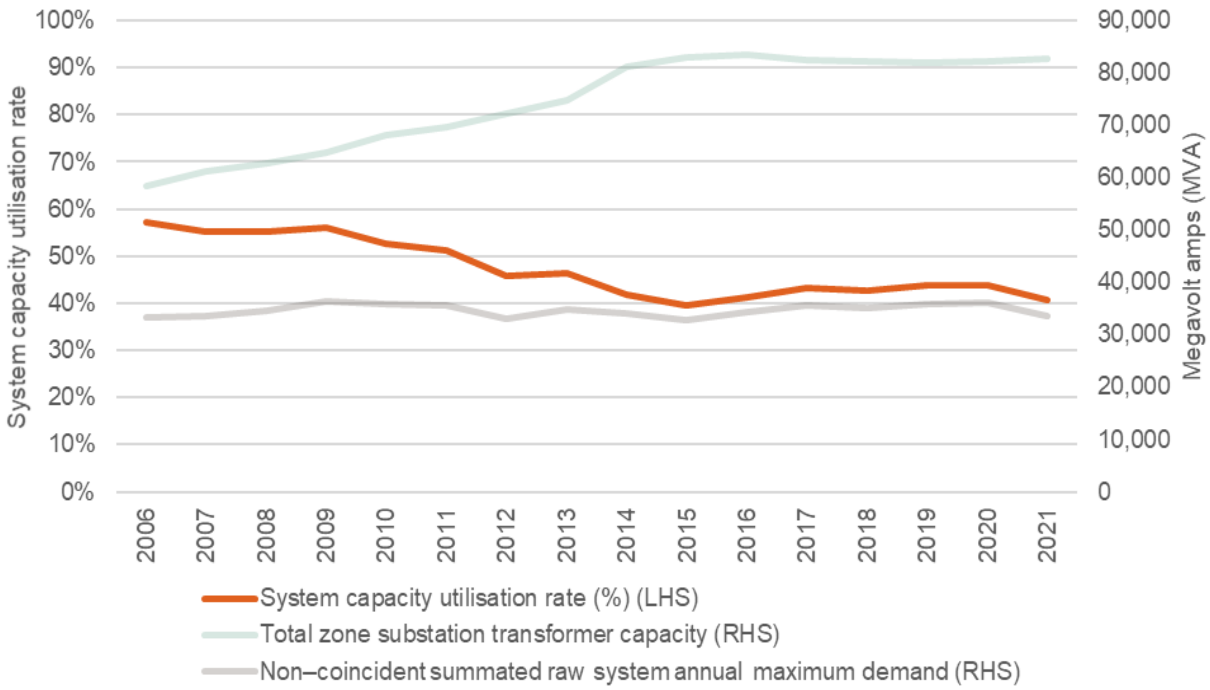
Utilisation is an informative but incomplete measure of the network assets' preparedness to respond to short term changes in demand given that low utilisation (or high spare capacity or redundancy) means the network can service large increases in demand. Some spare capacity is an important service output consumers can expect, as well as a natural side effect to network investment being lumpy in nature. However, low utilisation also means consumers are paying for network assets they rarely use. If utilisation is inefficiently low, consumers will be paying more for excess capacity than the benefits they gain from it. These situations can potentially be avoided by managing variations in consumer demand, such as by using more efficient price signals.

While informative, it is worth recognising that Figure 3-11 provides an aggregated network-wide measure of utilisation, which will mask localised issues.

In 2021, average distribution network utilisation reduced since 2020 from 44 per cent to 41 per cent. This differs from the previous trend of gradually increasing utilisation since a 2015 low of 39 per cent.

Lower maximum demand contributed to this result as we measure utilisation as the ratio of reported non-coincident maximum demand to total zone substation transformer capacity.

Figure 3-11 Distribution network utilisation - Total DNSPs

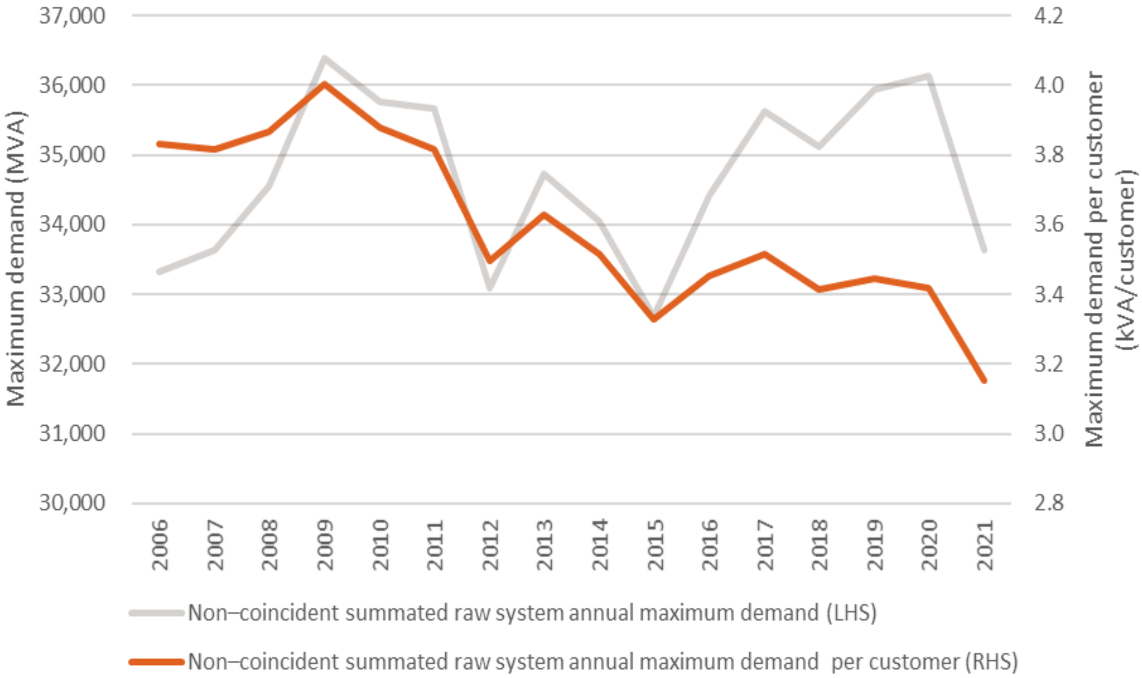


Source: Operational performance data, AER analysis.

In future years' reporting, we may expand on this measure to investigate the changing dynamics of per-customer demand. To illustrate, Figure 3-12 below compares changes in the measure of maximum demand used to calculate utilisation against its per-customer equivalent.

Maximum demand in 2021 is the lowest it has been since 2015 and per customer maximum demand has declined materially to the lowest it has been over our measurement period (commencing 2006). Further analysis could yield insights about the impacts of distributed energy resources and energy efficiency measures on use of the networks.

Figure 3-12 Changes in maximum demand and maximum demand per customer



Source: Operational performance data, AER analysis.

4 Summary of financial performance in 2021

This section looks at financial performance, or network profitability, as a core performance outcome. This entails considering indicators of profit that NSPs have been able to generate from the revenue allowances paid by consumers, including:

- returns on assets (section 4.1)
- earnings before interest and tax (EBIT) per customer (section 4.2)
- RAB multiples (section 4.3)
- returns on regulated equity (section 4.4)

The regulatory framework is designed to compensate NSPs in expectation for efficiently incurred costs (such as opex, depreciation, interest on debt and tax) and to provide them with an expected profit margin in line with the required return in the market for an investment of similar risk. The expected profit margin, if set at an appropriate level and supported by appropriate incentives, should attract efficient investment.

As a feature of the incentive-based regulatory framework, we expect NSPs' actual outcomes to differ from the forecasts and benchmarks we set. The revenue requirement is not a guaranteed return, as the NSPs' actual returns are determined in part by whether they spend more or less than the forecasts and benchmarks used to determine their revenue allowances. Nonetheless, to the extent that profitability results are systematically and materially higher or lower than forecast, this would prompt us to investigate the causes in more detail.

Forecast returns on capital

The return on capital building block included in our revenue determinations is made up of a return on debt component and a return on equity component. The return on debt, for example, is made up of the amount of debt we forecast (RAB × gearing; where gearing is the ratio of assets financed with debt rather than equity) multiplied by the allowed rate of return on debt. Equity is similar. We refer to the allowed rates of returns on debt and equity (in combination the weighted average cost of capital) as 'forecast' returns.

4.1 Returns on assets

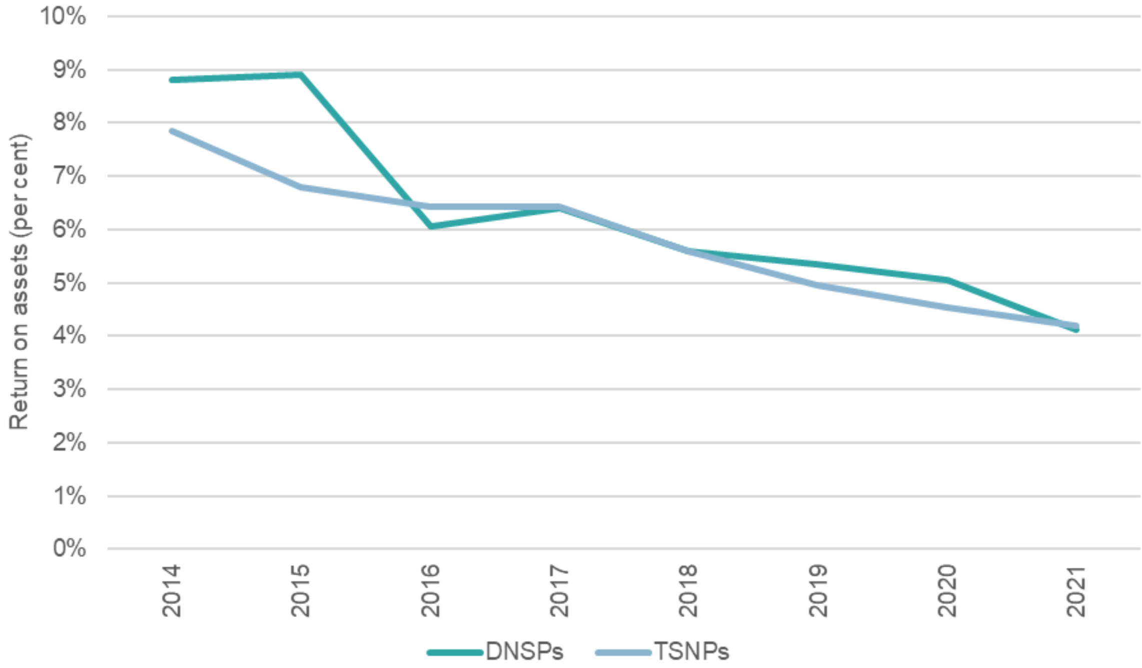
The return on assets is measured as EBIT divided by the RAB. It is a simple, partial profitability measure allowing us to compare NSP profits against our allowed rate of returns. It does not capture all potential drivers of NSPs' profits—in particular, it does not capture performance against our allowances for the costs of debt (interest expense) or tax expense. However, it does capture the impact of incentive scheme rewards and penalties, as well as performance against opex allowances.

In 2021, the average return on assets experienced by NSPs continued to decline; however:

- On average, NSPs continued to earn real returns on assets roughly 100 basis points above forecast. For instance, in 2021, the average real return on assets was 3.8% compared to a forecast of 3.0%
- The pattern in actual outcomes is largely consistent between DNSPs and TNSPs

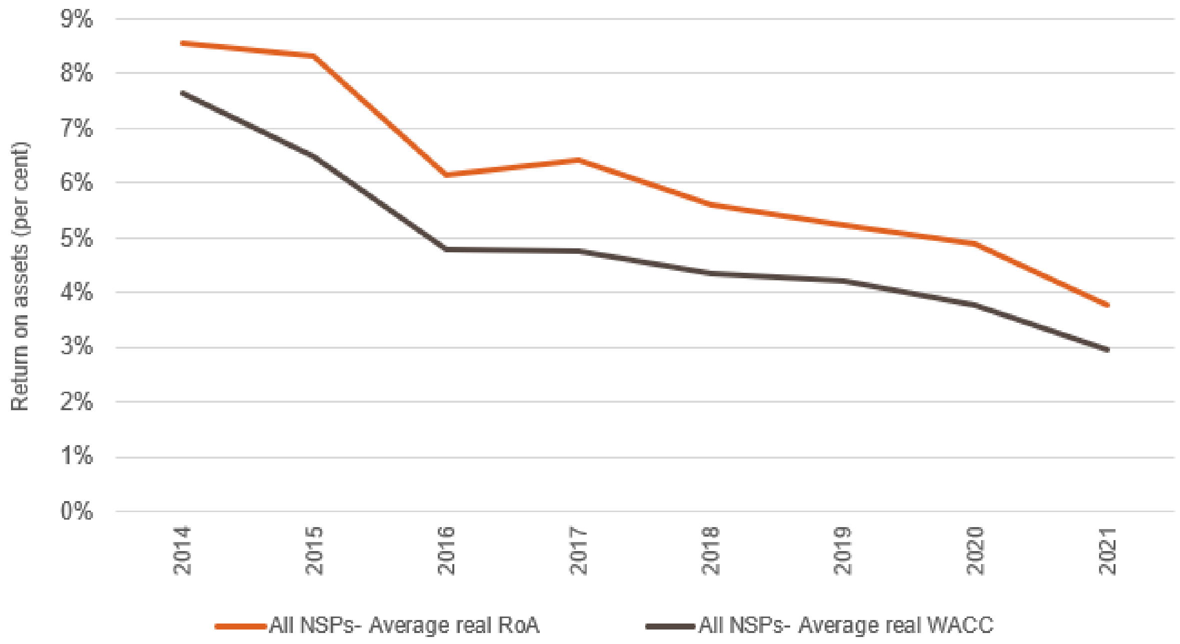
The decline in the average return on assets after 2019 was exaggerated by Power and Water's revenue first being set under an AER decision in 2020, and therefore not reflecting the 2014–19 averages. This effect is visible despite Power and Water's small size given Figure 4-1 Calculates a simple average of real returns on assets across DNSPs and TNSPs, rather than being weighted by NSP size. Power and Water's forecast and actual returns on assets are both relatively low due largely to having both of its return on debt and equity reset in a low interest rate environment.

Figure 4-1 Real returns on assets - DNSPs and TNSPs



Source: Financial performance data, AER analysis.

Figure 4-2 Real returns on assets compared to forecast real rate of return



Source: Financial performance data, AER analysis.

Figure 4-2 above shows NSPs have continued to generate real returns on assets which exceed forecast returns despite declining forecast returns.

We encourage stakeholders to review return on asset outcomes alongside our analysis of NSPs' returns on regulated equity, set out in section 4.4. Compared to that measure, the return on assets is less comprehensive but simpler to calculate and interpret. In combination, we consider they best equip stakeholders to form views on how network profits compare against the forecast returns on capital included in our revenue forecasts.

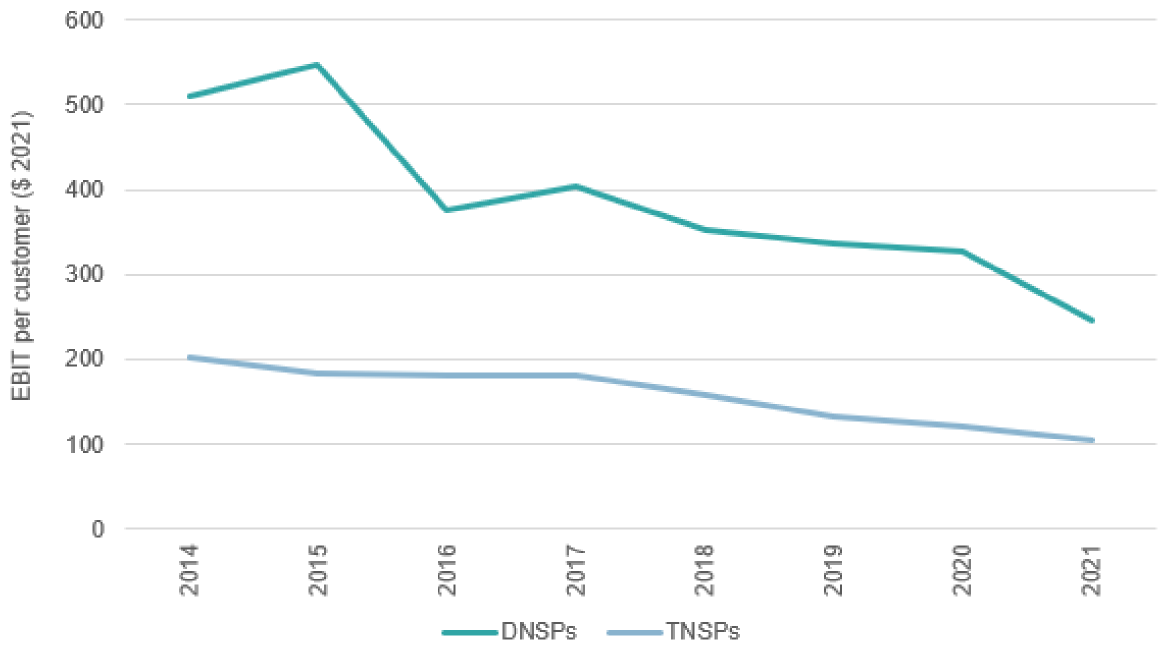
4.2 EBIT per consumer

EBIT per consumer is a measure of an NSP's operating profit divided by its consumer base. It complements the return on assets by capturing the same measure of profit (EBIT) over a different cost-driver. EBIT per consumer does *not* measure the profit that individual residential consumers contribute to their NSP. It is an average of all consumers, including businesses and large consumers who contribute substantially more network revenue per consumer.

Figure 4-3 sets out the average real EBITs per consumer, including incentive scheme payments and excluding the impacts of RAB indexation. In our view, this is the most informative single version of the EBIT per consumer measure. It uses an estimate of EBIT that is consistent with how it is calculated in estimating real returns on assets.[25]

25 We have published the financial performance datasets, which enables stakeholders to calculate the EBIT per customer (and return of assets and return of regulated equity), inclusive and exclusive of RAB indexation, incentive schemes and pass through revenues.

Figure 4-3 Average EBIT per consumer - Including incentive scheme payments and excluding RAB indexation



Source: Financial performance data, AER analysis

Over the 2014 to 2021 period, we observe that:

- EBIT per consumer declined across most NSPs.
- EBIT per consumer has converged between the NSPs. In 2014, the range of EBIT per consumer was $873 for distribution and $282 for transmission, whereas in 2021 the range was $362 for distribution and $102 for transmission.[26] There would have been several drivers of this convergence. One driver would have been the better regulation reforms where we transitioned NSPs to a trailing average return on debt and applied benchmarking to better align the opex allowances provided across NSPs.[27]
- We would expect these trends to continue because allowed returns on capital were reset under the 2018 binding rate of return instrument and have been reflected in the revenue determinations from 2018 onwards.

Our estimates of EBIT per consumer for TNSPs are materially lower than for DNSPs. This is a consequence of the higher capital intensiveness of distribution networks compared to transmission networks—that is, distribution networks typically have larger RABs per customer. However, it does not mean that TNSPs are less profitable than DNSPs for the same levels of investment.

26 Range refers to the difference between the highest (maximum) and lowest (minimum) values of the set of DNSPs or TNSPs.

27 Return on debt reforms increased convergence of NSPs' allowed returns on debt, which became updated annually and averaged over ten years rather than set at a point near the start of each NSP's regulatory control period. Increased use of benchmarking when setting opex allowances could have also increased convergence as NSPs with relatively high opex allowances had their allowances scaled back to better align with NSPs that the AER deemed to be more efficient. For more information on our 2013 Better Regulation reforms, see AER, *Better Regulation*, accessed 11 April 2022.

4.3 RAB multiples

An NSP's RAB multiple is calculated as the NSP's enterprise value divided by its RAB. RAB multiples are a measure of investor expectations about an NSP's future returns and are widely used by market analysts in connection with regulated utilities. At the time of the relevant transaction, they are forward-looking, whereas profitability measures are based on historical outcomes. Since most of our regulatory approaches are predictable and set out in guidelines, we expect an environment where returns had been systematically insufficient would be evident in RAB multiples.

Several factors affect RAB multiples, some of which are not direct outcomes of the regulatory regime or the NSPs' core regulated services. For example, RAB multiples may be affected by unregulated revenue, expectations of future capital expenditure pathways, any expected outperformance of relevant expenditure benchmarks. CEPA have been investigating this relationship as part of our 2022 rate of return instrument review.[28] Despite such complexities, advice Biggar gave when we developed the 2018 rate of return instrument indicates there is a "normal range" we might expect to see when observing RAB multiples:[29]

> *In my view, due to each firm's ability to earn rewards for taking desirable actions, an Enterprise Value (EV)/RAB ratio of slightly above one should be considered normal. This is consistent with the theoretical observation that the regulated firm must be left some "information rents" in an optimal regulatory contract. I therefore suggest that, as a starting point, an EV/RAB in the vicinity of 1.1 should be considered unobjectionable. In addition, due to uncertainties and complexities in the regulatory process, and in the process of estimating the EV and the RAB, I suggest an error margin of plus or minus twenty per cent on this figure could be considered a "normal range". I therefore suggest that an EV/RAB outside the range of 0.9-1.3 might give cause for further exploration and investigation.*

For these above reasons, we do not expect RAB multiples to be precisely at one under a well-functioning regulatory regime and consider RAB multiples somewhat above one would not necessarily indicate a problem. This is consistent with the approach followed by a range of other regulators that use RAB multiples as a reasonableness check or to inform allowed rates of return.

To draw on the largest possible body of market evidence, we have reported on two types of RAB multiples, sourced from Morgan Stanley:

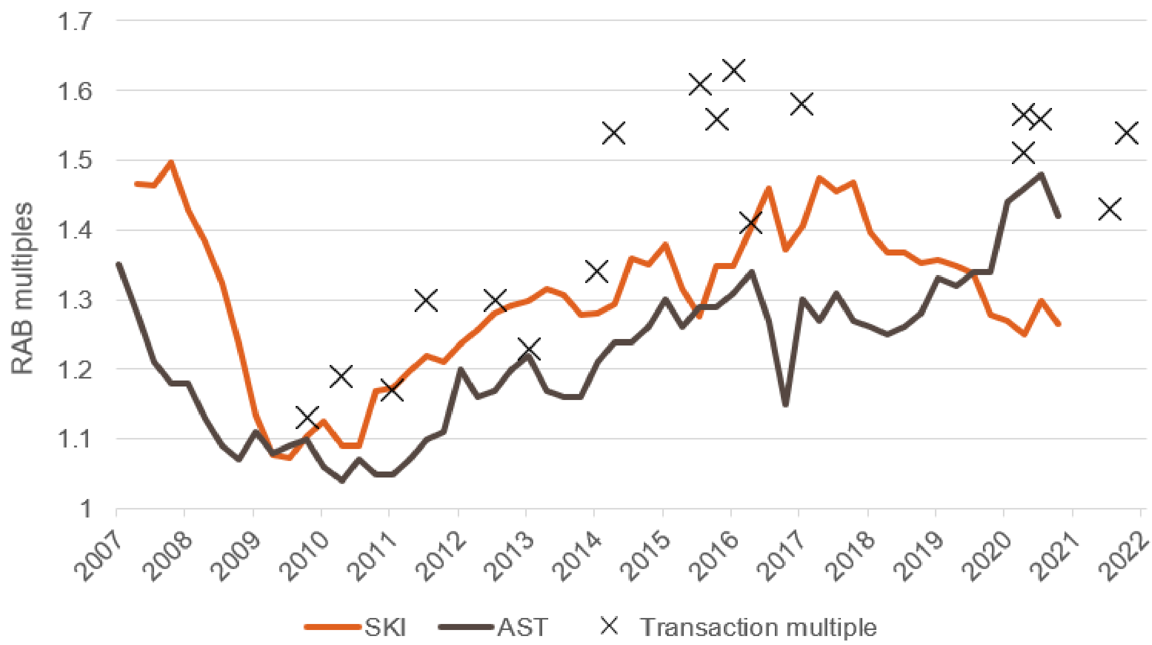
- Transaction multiples – RAB multiples arising from the transaction of a discrete component of an ownership group, including regulated NSPs.
- Trading multiples – RAB multiples generated using market value data on the enterprise value of relevant publicly listed entities. The two relevant publicly listed entities, SKI (Spark Infrastructure) and AST (AusNet Services) were delisted from the Australian Securities Exchange (ASX) on 23 December 2021 and 17 February 2022, respectively. As such, we expect that no new relevant trading multiples will be available in the foreseeable future.

28 CEPA, EV/RAB multiples, 10 May 2022.

29 Darryl Biggar, *Understanding the role of RAB multiples in the regulatory process*, 2018.

Figure 4-4 combines our time series of both trading and transaction RAB multiples.

Figure 4-4 AER regulated NSPs - transaction and trading multiples



Source: Morgan Stanley Research, AER analysis.[30]

Note: SKI is Spark Infrastructure, which holds ownership stakes in SA Power Networks (49%), Victoria Power Networks (49%) and TransGrid (15%). AST is AusNet Services, which owns a Victorian electricity distribution network, electricity transmission network and gas distribution network.

Despite the drivers of RAB multiples being difficult to quantify precisely, we have seen, for a number of years, the businesses we regulate traded at multiples well above 1.0. Further, we have seen vigorous competition among investors for these assets. In this context, it is difficult to conclude there is a material under-remuneration of investors. Rather, we consider RAB multiples indicate that investors are confident in the current and future regulatory returns as being sufficiently high to remunerate their costs.

In the 2021 regulatory year, OMERS acquired a 19.99% stake in TransGrid in July 2020 at a RAB multiple of 1.57. This is approximately the same RAB multiple at which the privatisation of TransGrid took place at in 2014.

SKI and AST were delisted from the ASX with a final trading multiple of 1.27 and 1.42, respectively. However, this occurred in the 2022 regulatory year.

30 Figure 4-4 includes transaction multiples that occurred in the 2022 regulatory year; SKI and Ausgrid int the second half of 2021 and AST and ElectraNet in the first half of 2022.

4.4 Returns on regulated equity

The return on regulated equity illustrates the final returns available to equity holders after all expenses. This allows the most comprehensive comparison of NSPs' actual returns against expected returns. Unlike the return on assets and EBIT per consumer, the return on regulated equity is based on net profit after tax (NPAT) rather than EBIT. As such, it also captures returns arising from differences between an NSP's:

- actual tax expense and forecast tax allowance, and
- actual interest expense and forecast return on debt allowance.

Returns on regulated equity require care to interpret. They reflect the treatment of network revenue and expenses in the building block revenue framework and in our models—for example, valuing network assets using the RAB rather than a separate book or market value. This is necessary for comparing the measure against our forecast returns on equity, but also means there are differences between our approach and how a return on equity would ordinarily be calculated. The impacts of these differences are published in PwC's advice.[31] Our analysis and financial performance measures data should be considered alongside PwC's advice, our profitability measures review final decision[32], as well as our explanatory note and illustrative return on regulated equity model published alongside this report.

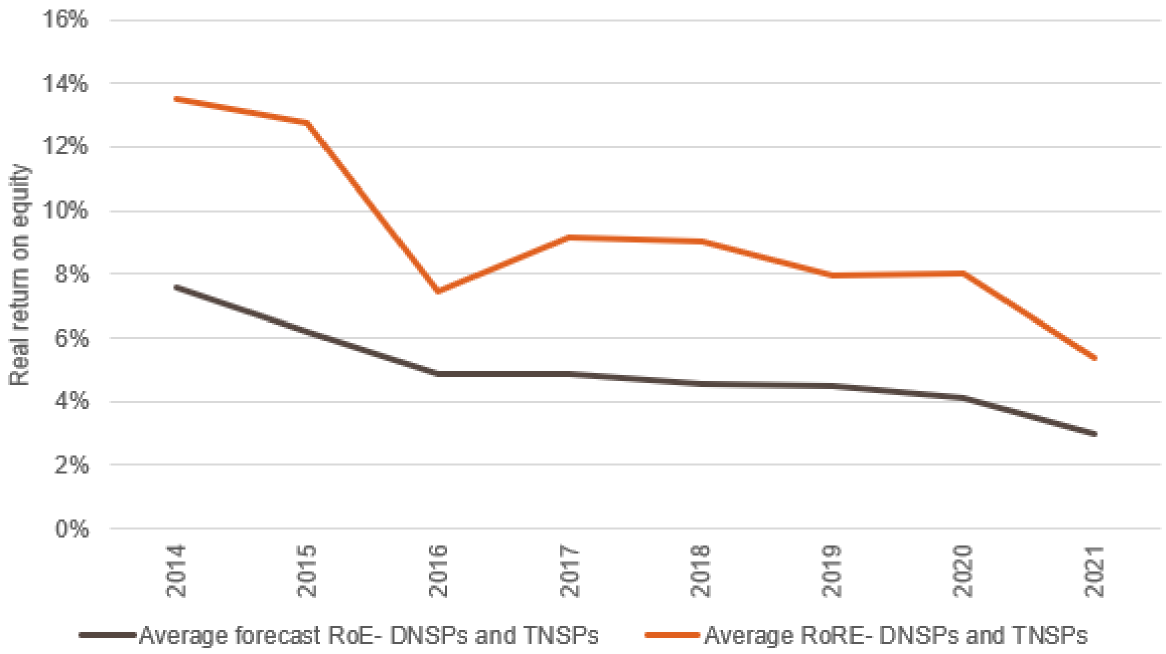
4.4.1 What returns are network service providers achieving?

Over 2014 to 2021, NSPs have on average achieved higher returns on regulated equity than forecast.

31 PwC, *Appendix A - High level publishable summary: Review of the NSPs' response to the AER's profitability measures information request*, 2021.

32 AER, *Profitability measures for electricity and gas network businesses*, December 2019.

Figure 4-5 Real returns on regulated equity compared to forecast returns on equity—DNSPs and TNSPs



Source: Financial performance data, AER analysis

Over 2014 to 2021:

- Average NSP returns on regulated equity declined materially
- Despite this, NSPs achieved returns on regulated equity which exceed forecast returns on equity by approximately 4.2 percentage points on average – notwithstanding that this difference was 2.4 percentage points in 2021.
- This occurred against a backdrop of declining forecast returns on equity. This decline has progressed as:
  - interest rates have declined, including the rates on Commonwealth Government Securities on which we forecast the risk-free rate
  - we have applied the 2013 rate of return guideline and, from 2020, have begun to apply the 2018 binding rate of return instrument. So far, the 2018 instrument has applied to five DNSPs and one TNSP.
- The difference between forecast and real returns was higher in the earlier years and narrowed materially after the introduction of the 2013 rate of return guideline.

The results appear consistent with the outcomes we observe in NSPs’ returns on assets and in RAB multiples, giving us greater confidence in the outcomes of the measure.

We also observe that:

- Underneath the average results, there is a spectrum of outcomes between NSPs, with some earning persistently higher returns

- All but one NSP has achieved returns at or above their forecast returns in most if not all years[33]

It is not unexpected that NSPs' returns would exceed forecast returns under a regulatory framework that provided them with a reasonable opportunity to recover at least the efficient costs of providing core regulated services.[34] However, whether these results are evidence of the framework operating effectively or not depends on the drivers and materiality of the results, including whether they are caused by:

- Temporary revenue over-collections which will be passed back to consumers in the short-term
- Departures from our benchmark financing structures through which some NSPs have taken on higher risk to achieve higher returns
- NSPs spending less than forecast revenue building blocks due to efficiency gains
- NSPs spending less than forecast revenue building blocks due to shortcomings in our approach to estimating network revenue requirements, or to forecasting errors that, if unbiased, might be expected to even out over time

4.4.2 What is driving these results?

This section analyses which factors have driven differences between forecast returns and what the NSPs have achieved. Our analysis suggests a combination of the factors mentioned above drive differences between forecast and actual returns on regulated equity.

Figure 4-6 sets out the average impact of different drivers in explaining the margin between:

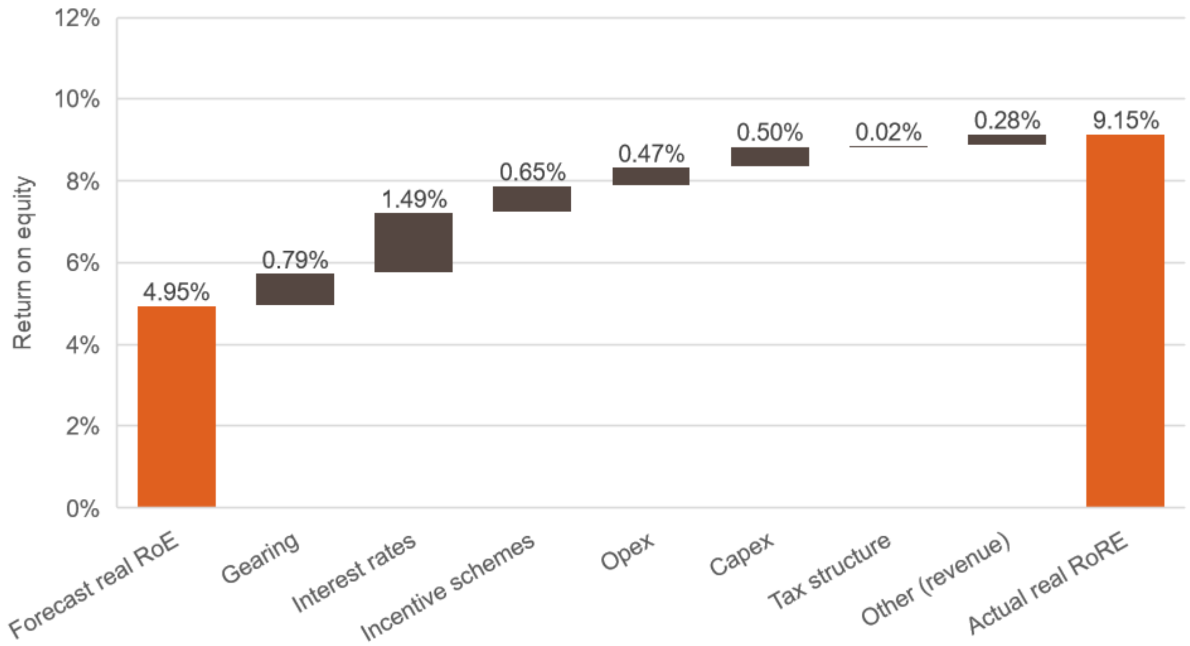
- forecast real returns on equity—that is, excluding returns from indexation of the RAB; and
- actual real returns on regulated equity

Instead of Figure 4-6, it would also be possible to compare nominal forecast returns on equity (which include returns from RAB indexation) against actual nominal post-tax returns on equity. While both comparisons are reasonable, we focus on comparing real returns as we are more interested in considering variables that are within NSPs' control. Comparing nominal returns would also highlight the revenue impacts of forecast inflation differing from outturn inflation.

33 In 6 of 8 years from 2014 to 2021, Essential Energy did not achieve returns at or above the forecast returns.

34 As required under the National Electricity Law, 7A(2)(a).

Figure 4-6 Incremental contributions to returns on regulated equity – simple average of all NSPs over 2014–2021



Source: Financial performance data, AER analysis

Note: We have calculated incremental contributions by substituting our forecast of each factor for an NSP in place of its reported actuals. For example, for opex contributions, we substitute forecast opex from our PTRM in place of actual opex used in calculating the real return on regulated equity. We calculate the incremental change in returns with each new factor for each NSP in every year of the time series.

While Figure 4-6 shows averages and is informative, the effects of the different factors change between NSPs and through the reporting period.

It is worth noting that even a small difference in the actual interest rate relative to what was forecast will have a large impact on the incremental return on regulated equity. This is illustrated by:

- the incremental contribution of interest rates shown in Figure 4-6 is 149 basis points. This contribution is calculated based on what the return on regulated equity (or regulatory net profit after tax divided by regulated equity) would be if the interest on NSPs' interest-bearing liabilities equalled the allowed return on debt.
- the difference between the allowed cost of debt and actual cost of debt is much narrower than 149 basis points and is of a similar magnitude to what we have found in the Energy Infrastructure Credit Spread Index (EICSI).[35] There are several reasons why these rates could differ – including NSPs having a different credit rating higher to the benchmark and raising debt outside the averaging period used to calculate the allowed return on debt.

[35] The difference in the EICSI and allowed return on debt is18 basis points. See AER, *Rate of return: Overall rate of return, equity and debt omnibus – Final working paper*, December 2021.

5 Focus area: Progress and impacts of network tariff reform

DNSPs are required to gradually make their tariffs better reflect the costs of serving their customers.[36] Charging their customers in a way that reflects the costs of network services should encourage more efficient use of the network, resulting in people better utilising the existing network instead of paying more to build it out. Efficient use includes better integration and use of distributed energy resources (DER) such as solar PV, batteries, and electric vehicles.

DNSPs pass network tariffs to direct customers, which are often retailers who package up network charges with other energy-related costs. Retailers can also manage their exposure to these costs in other ways, such as introducing offerings to their customers to manage their demand or though providing cross-subsidies. Retailers offer different fixed and variable tariffs to appeal to different end-use customers. End-use customers who choose a retail offer that involves network costs changing with the time of the day may be more likely to change their energy consumption habits.

This section reports on the progress of reforming network tariffs to better reflect the costs of providing network services to DNSPs' customers. We look at:

- What has happened since 2017 when tariff structure statements were introduced that require DNSPs to set out how they will transition to more cost reflective tariffs, including what new time of use and demand tariffs DNSPs have offered (section 5.1).
- How many residential and small business customers have a smart meter installed, and who of those are on cost reflective tariffs (section 5.2). We first received data to perform this analysis at the end of 2021.
- Data on network revenue and demand by chargeable quantities (broad tariff classes) to identify whether there is evidence of load switching as more cost reflective tariffs are introduced (section 5.3). For example, is there evidence that end-use customers have started using a smaller proportion of electricity at peak times?
- What factors might drive the uptake of cost reflective tariffs in the future (section 5.4).[37]
- What innovative tariffs have DNSPs trialled over 2018 to 2021 (section 5.5).

Key findings:

- The transition to more cost reflective tariffs has been slow and constrained by the slow pace of the smart meter roll out in most jurisdictions and the slow assignment of end-use customers to more cost reflective tariffs.
- While smart meters are a pre-requisite for cost reflective tariffs, other factors, such as assignment policy, also matter. Assignment policy refers to end-use customers' flexibility to opt into or out of cost reflective tariffs. When faced with uncertainty about the impact of cost reflective tariffs, end-use customers are less likely to opt-in to the option despite the potential benefits to the customer base and potentially to themselves. This is illustrated by Victoria, where smart meter penetration is nearly 100 per cent, but end-use customer

36 As per the pricing principles in clause 6.18.5 of the NER.

37 ECA, *Sentiment and behaviour surveys 2021*, accessed 4 April 2022.

take-up of cost reflective tariffs is a bit over 5 to 30 per cent on average, depending on the DNSP.

- While the uptake of smart meters and cost reflective tariffs has been slow, we expect this will pick up over the next few years. A high proportion of end-use customers that ECA surveyed have or are intending to purchase DER or other technologies to manage their energy use, which would typically trigger smart meter installation. Among other things, the Australian Energy Market Commission's (AEMC's) metering services review is expected to result in reforms that accelerate the smart meter roll out.[38] While smart meters do not necessarily result in the use of cost-reflective tariffs, they are a (1) prerequisite for them, and (2) trigger for customer reassignment to them, unless they can and choose to opt-out.

5.1 Network progress of tariff reform – Tariff Structure Statements

In 2017, we commenced the first round of DNSP tariff structure statements, which identify how DNSPs would transition to more cost reflective tariffs over their next regulatory control periods.[39]

We approved opt-in approaches to end-use customer assignment in the initial round of tariff structure statements. It is widely accepted that requiring customers to opt-in to new tariffs results in slower uptake than if customers are assigned to new tariffs with the option to opt-out.

We are currently consulting with DNSPs on the second and third rounds of tariff structure statements. As part of these consultations, we are supporting mandatory assignment or default assignment with the option to opt-out for customers with smart meter technologies installed. We expect this approach will materially increase the number of end-use customers who face cost reflective tariffs. While supporting mandatory assignment, our consumer vulnerability strategy also prompts us to also consider complementary work to enhance accessibility and use the consumer voice to inform regulatory design. Approaching tariff reform holistically is valuable, particularly as vulnerable consumers may face greater challenges responding to price signals.[40]

Appendix A summarises the types of tariffs that DNSPs provided under in the first round of tariff structure statements, for residential and small-medium business customers, respectively. Once an end-use customer is assigned to a particular tariff, the DNSP will pass the relevant charges onto its direct customers, which are generally retailers. Retailers can choose to pass the relevant network tariffs though to their customers but may choose to package these costs up in a different way.

5.2 Smart meter roll out

A key barrier to assigning residential and small business customers to cost reflective network tariffs is the type of metering technology installed. Accumulation meters are still the predominant

38 AEMC, *Directions paper: Review of the regulatory framework for metering services*, September 2021.

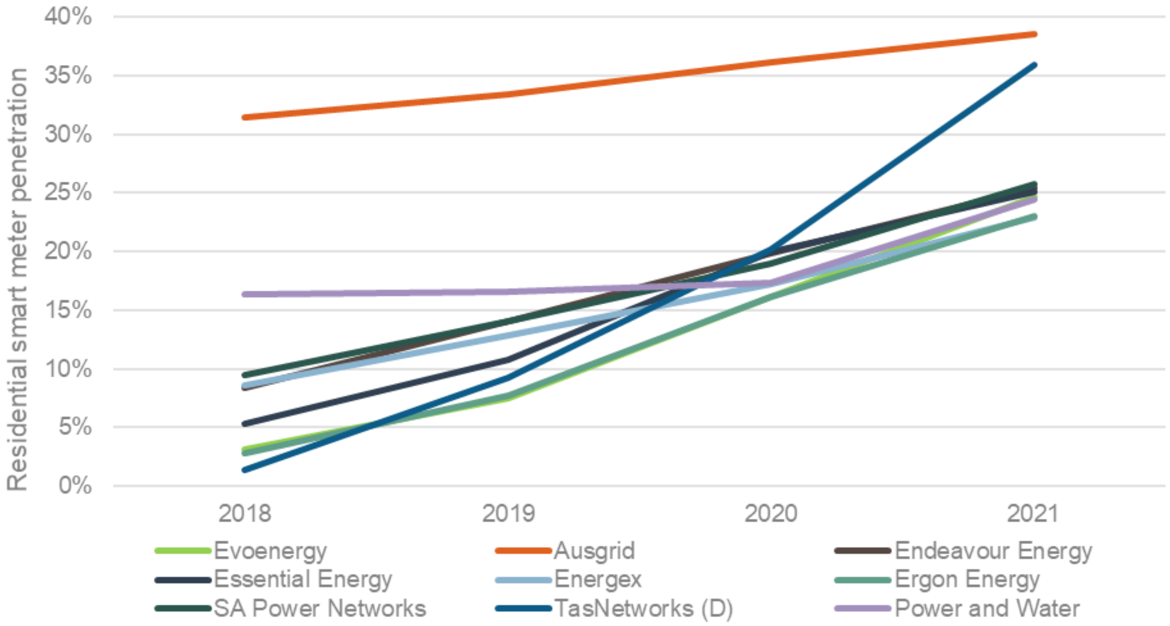
39 AER, *Pricing proposals & tariffs*, accessed 6 April 2022.

40 AER, *Consumer vulnerability strategy: Draft for consultation*, December 2021, p. 43.

type of meter used outside Victoria. These meters measure how much energy is consumed over a period, but not the time of day.

Smart meter installations outside of Victoria have increased over 2018 to 2022, although at rates below the minimum 50 per cent penetration required to realise the benefits.[41] The rate of smart meter deployment for residential and non-residential customers varies across each DNSP and jurisdiction as shown in Figure 5-1 to Figure 5-6. In these figures, we report 'smart meters' as the sum of Type 4 and Type 5 meters.

Figure 5-1 Percentage of residential customers with a smart meter by DNSP*

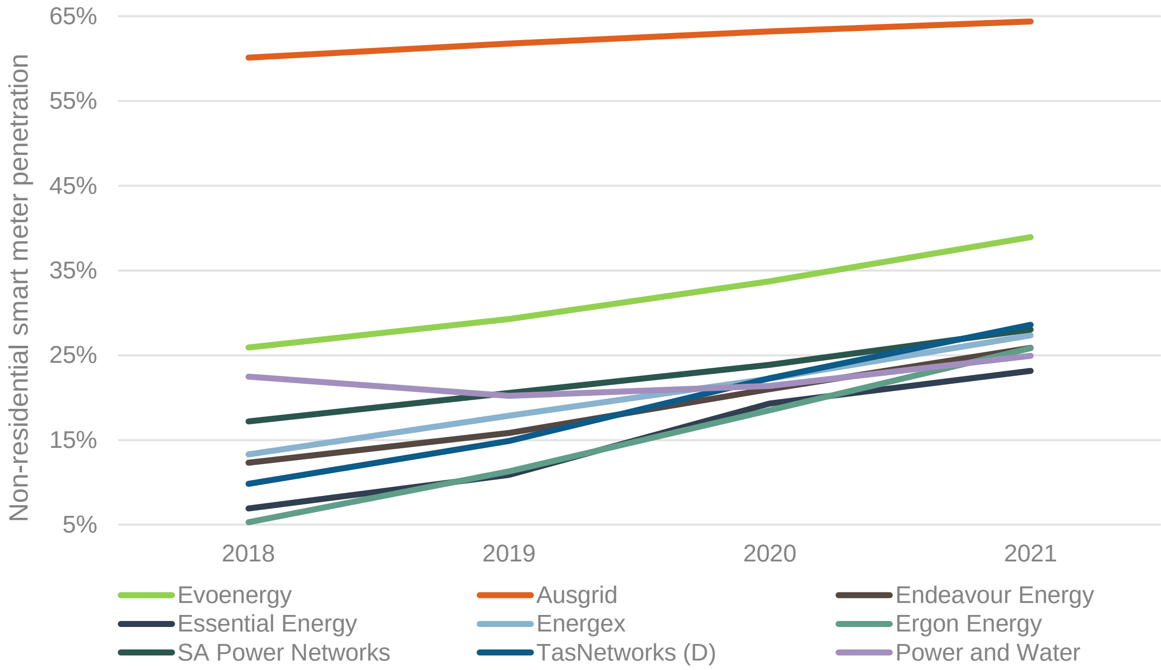


Source: Annual RIN, AER analysis

* Victorian DNSPs have been excluded from this graph as nearly 100% of residential customers in Victoria have smart meters.

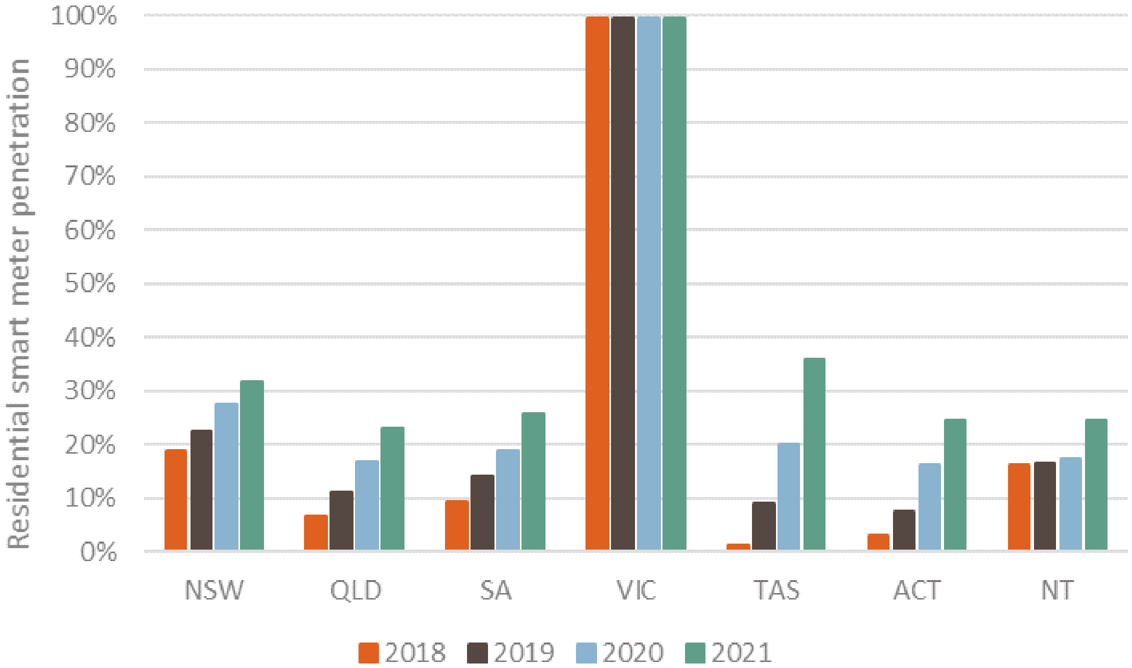
41 AEMC, *Directions paper: Review of the regulatory framework for metering services*, September 2021, p. i.

Figure 5-2 Percentage of non-residential customers with a smart meter by DNSP[42]



Source: Annual RIN, AER analysis

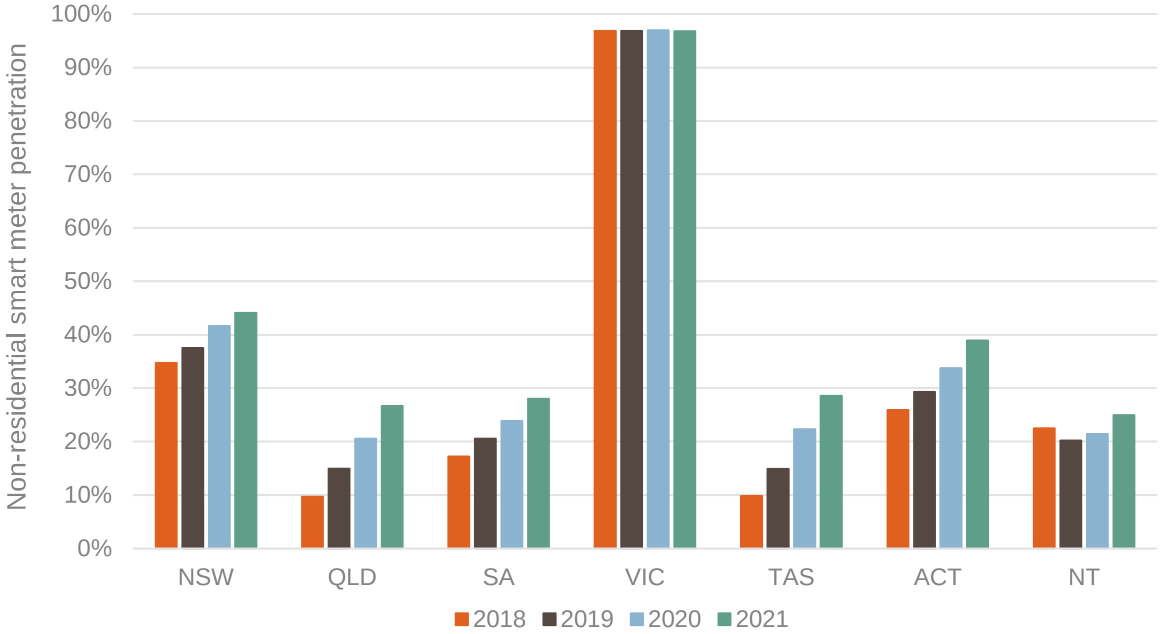
Figure 5-3 Percentage of residential customers with a smart meter by jurisdiction



Source: Annual RIN, AER analysis

42 Victorian DNSPs have been excluded from this graph as 95¬-98% of non-residential customers in Victoria have smart meters. Essential Energy's Annual Reporting RIN data in relation to "Non-residential customers" NMI count of Type 6 meters has been updated to 78,229 to correct a reporting error.

Figure 5-4 Percentage of non-residential customers with a smart meter by jurisdiction*



Source: Annual RIN, AER analysis

Figure 5-1 to Figure 5-4 highlight how the Victorian DNSPs' roll out of smart meters, which was practically completed at the end of 2015,[43] contrasts with the residential and non-residential smart meter installations in other jurisdictions.

The installation of smart meters in the other jurisdictions has increased steadily, with non-residential customers having a slightly higher proportion of smart meters than residential customers. In comparing these DNSPs, the highest proportion of installations are in Evoenergy's and Ausgrid's networks, especially for non-residential customers.

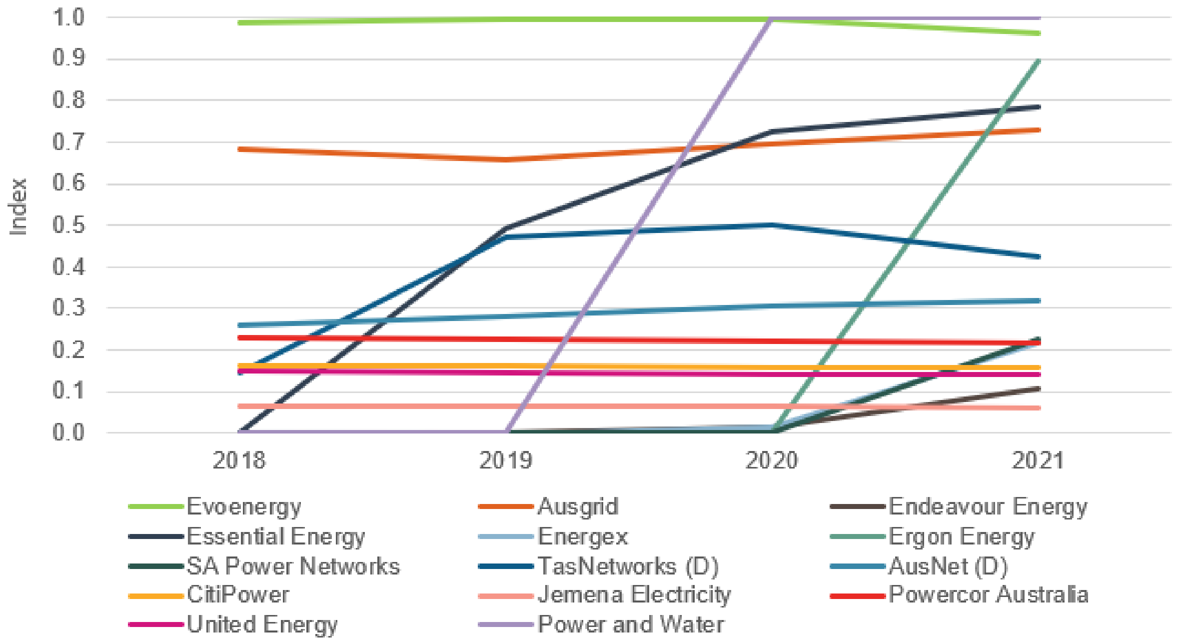
Despite the ubiquity of smart meters in Victoria, few Victorian residential and non-residential customers are on cost reflective tariffs. The small proportion of Victorian end-use customers with smart meters on cost reflective tariffs may be due to the rollout being practically completed at the end of 2015,[44] before the tariff structure statements commenced. As reported in Appendix A, under the initial round tariff structure statements, existing smart meter customers had to opt-in to a cost reflective tariff in Victoria.

Figure 5-5 and Figure 5-6 compare the smart meter installation percentage for each DNSP against the percent of end-use customers on a cost reflective tariff.

43 AER, *Final decision - AMI transition charges applications*, 2016, p. 4.

44 AER, *Final decision - AMI transition charges applications*, 2016, p. 4.

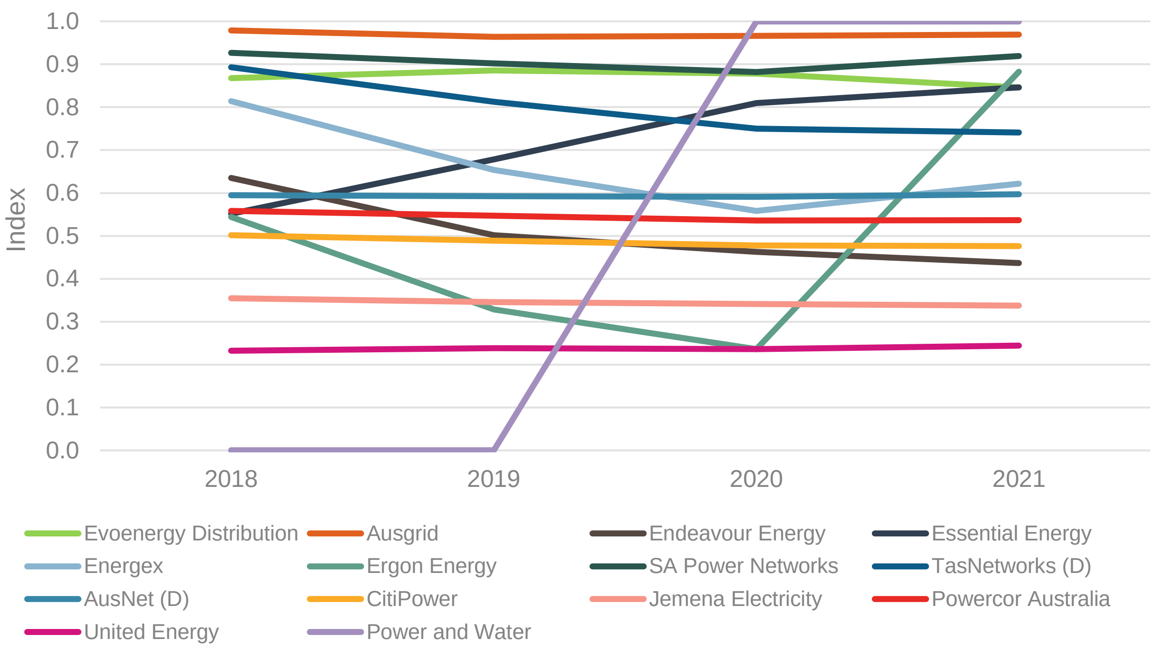
Figure 5-5 Index of residential customers on cost reflective tariffs compared to smart meter installation



Source: Annual RIN, AER analysis

Figure 5-5 shows that on a Victorian DNSP average, for each 100 residential customers with a smart meter, only 18 are on cost reflective tariffs.

Figure 5-6 Index of non-residential customers on cost reflective tariffs compared to smart meter installation



Source: Annual RIN, AER analysis

Figure 5-6 shows a higher number of non-residential customers on cost reflective tariffs, with the Victorian DNSP average measuring 44 customers for each 100 non-residential customers with a smart meter.

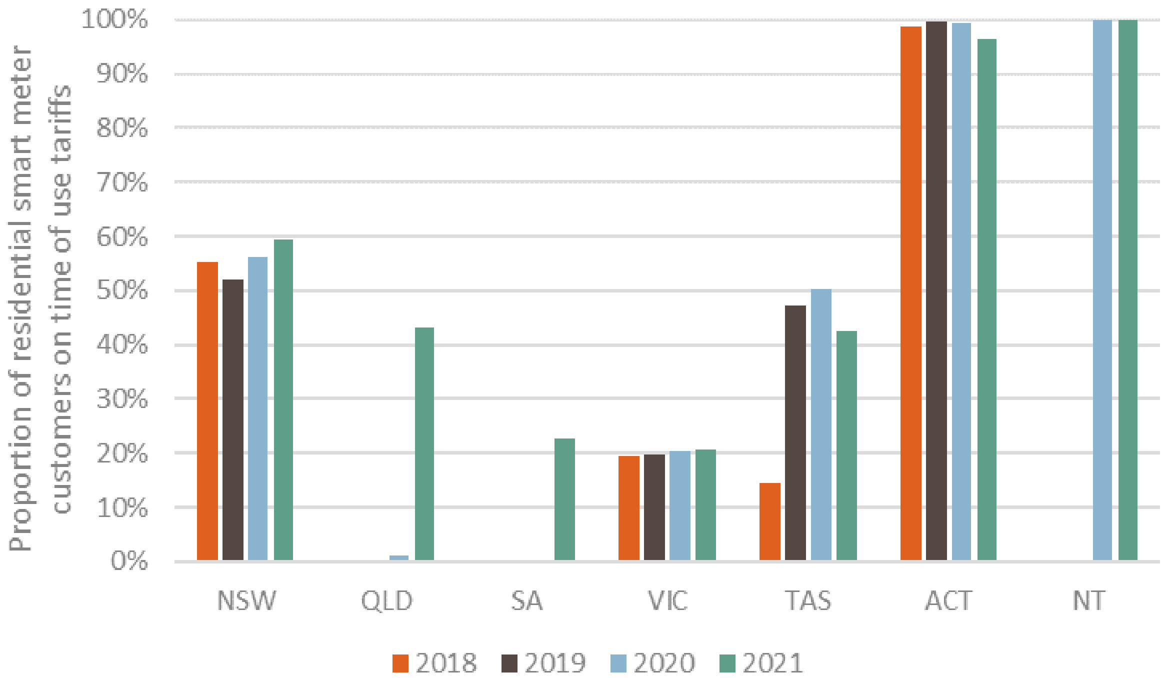
For many other jurisdictions, there has been a steadily higher number of residential customers with a smart meter installed on cost reflective tariffs (or a notably higher number, such is the case for Evoenergy and Ausgrid). Further, Essential Energy, Ergon Energy and Power and Water in the 2020 or 2021 regulatory years have significantly increased the number of residential customers with a smart meter installed who are on a cost reflective tariff.

For non-residential customers with a smart meter installed, each DNSP except Endeavour Energy in the other jurisdictions in 2021 is reporting, at least 62 non-residential customers on a cost reflective tariff for each 100 non-residential customers with a smart meter installed. This higher number is driven by Evoenergy, Ausgrid, Essential Energy, Ergon Energy, SA Power Networks and Power and Water having at least 85 non-residential customers on a cost reflective tariff for each 100 non-residential customers with a smart meter installed.

The higher number of customers with a cost reflective tariff in the other jurisdictions is due to the different approaches to tariff assignment as noted in Appendix A. These jurisdictions require end-use customers to opt-out of a cost reflective tariff. The effect of this assignment policy appears to have driven a proportionately higher number of end-use customers with smart meters to have a cost reflective tariff.

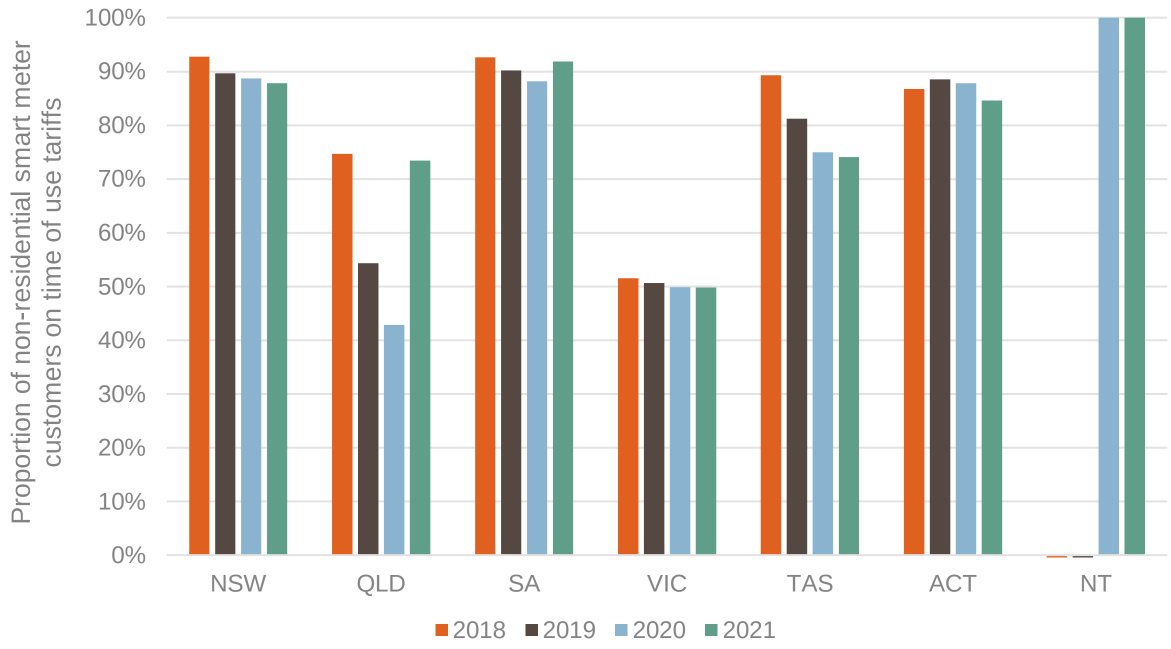
For a more aggregated view, Figure 5-7 and Figure 5-8 present this information on a jurisdictional basis.

Figure 5-7 Proportion of residential customers with smart meters on cost reflective tariffs by jurisdiction



Source: Annual RIN, AER analysis

Figure 5-8 Proportion of non-residential customers with smart meters on cost reflective tariffs by jurisdiction



Source: Annual RIN, AER analysis

5.2.1 What drives a smart meter installation?

The installation of smart meters and their coordination in jurisdictions outside of Victoria is not the responsibility of DNSPs. Smart meter installations are currently triggered by the following events:[45]

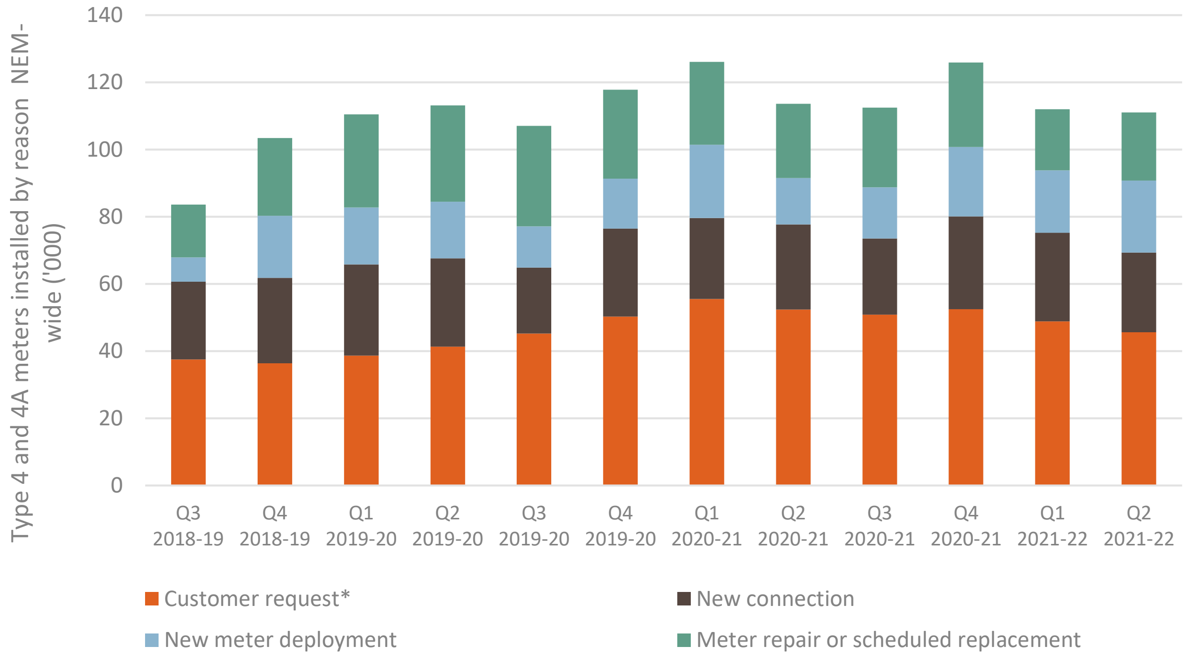
- Connection upgrade from single phase to three phase
- The installation of a solar PV system
- Replacement of the old accumulation meter
- New connections.

Our retail quarterly report also collects data on the number of type 4 & 4A smart meters installed by reason.[46] While Figure 5-9 shows that *"customer requests"* form a main reason for installing smart meters, this category should be interpreted more broadly than customer requests. This category also includes events initiated by end-use customers that trigger a smart meter installation, such as installation of a solar PV system or a multi-phase connection upgrade. In these cases, smart meter installations may be a flow-on consequence of end-use consumers demanding a different product.

45 Connection upgrades and installation of solar PV are categorised under the definition of "new meter deployment" as defined under the NERR. specifically, NERR, r.3(a) refers to where the replacement is at the requests of the relevant small customer or to enable the provision of a product or service the customer has agreed to acquire from the retailer or any other person.

46 Smart meters as a category of meters includes by type 4 and 4A. Type 4 is remotely read advanced meter, and type 4a is with its remote connection disabled in certain circumstances such that it must be read manually. AEMC, *Rule determination: National electricity amendment (Meter installation - Advanced meter communications) Rule*, March 2019, p. i.

Figure 5-9 Type 4 and 4A meters installed by reason - All DNSPs excluding Victoria ('000)



* 'Customer request' also includes requests for other technologies that require a smart meter to be installed
Source: AER Retail Performance data, AER analysis.

5.3 Energy delivered and network revenue recovered by chargeable quantities

This section investigates whether energy delivered and network revenue recovered by chargeable quantities can provide any information about the early impact of tariff reform.

Given low levels of cost reflective network tariffs, data on quantities of energy delivered and network revenues by chargeable quantity should be interpreted with caution when making inferences based on current progress tariff reform. As more end-use customers go on cost reflective network tariffs, more meaningful observations on these metrics should become possible.

We collect DNSP data on network revenue recovered (Figure 5-10) and energy delivered (Figure 5-11) by the following categories of chargeable quantities:[47]

- Fixed charges
- Volumetric tariffs (for example, flat tariffs, block tariffs)[48]

47 Chargeable quantities of revenue and energy delivered are collected in the Economic Benchmarking RINs. In addition to the categories discussed in this report, we also collect data on quantities charged for standard control services under the following categories: unmetered supplies (e.g. public lighting), contracted maximum demand charges, measured maximum demand charges, and other sources.

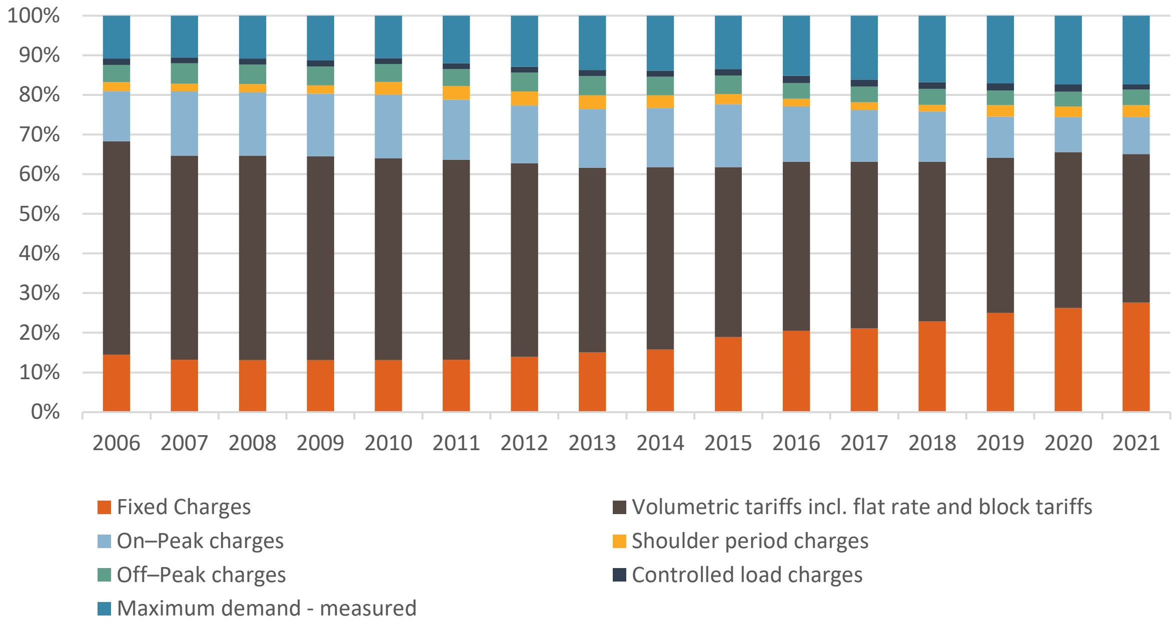
48 Our economic benchmarking data collection uses the chargeable quantity category of "*time of use is not a determinant*'. This refers to flat tariffs or volume-based tariffs that do not vary by time day, day of week, or month of year. These tariffs are typically called single rate or flat rate tariffs.

- Shoulder times
- On-peak times
- Off-peak times
- Controlled load, which are charged through tariffs offered in connection with allowing the DNSP to control load (for example, off-peak hot water systems)
- Maximum demand measured, where charges are based on measured maximum demand (not including contract maximum demand).

These metrics allow us to track the variability across categories that we expect would be influenced by end-use customers switching to more cost reflective tariffs. These metrics indicate there has been some load switching away from peak charging periods in recent years for end-use customers that are charged more for consuming during those periods. This is where peak charging periods are defined in accordance with network tariff structures and can therefore vary between DNSPs.

Figure 5-10 also shows that in recent years, DNSPs have been collecting a greater proportion of their network revenue through fixed charges. Unless fixed charges are more cost reflective, this potentially mutes price signals designed to reduce network constraints by incentivising efficient behaviours, such as shifting consumption away from periods of peak demand.

Figure 5-10 Network revenue by chargeable quantity (per cent) – All DNSPs



Source: Economic Benchmarking RIN, AER analysis.

Since 2016, there has been observable movement between the network revenue collected under different energy delivery charge categories across the NEM. For instance, network revenue collected through:

- Fixed charges increased by 9.2 per cent

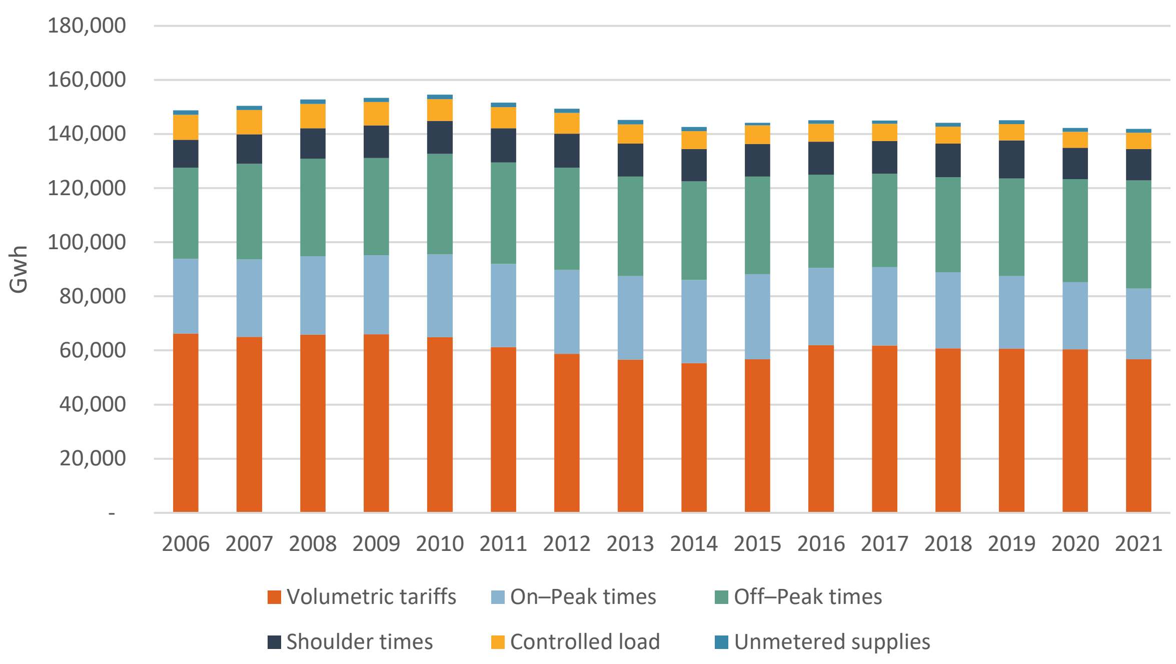
- Energy delivery charges where time of use is not a determinant (that is, flight-rate tariffs or clock tariffs) declined by 4.9 per cent
- On-peak energy charges declined by 5.1 per cent.
- Shoulder period energy charges increased by 1.3 per cent
- Controlled load customer charges declined by 0.7 per cent.
- Maximum demand (measured) revenue increased by 2.2 per cent.

Energy delivered by chargeable quantities indicates how and when end-use customers are consuming electricity. Across the NEM, total energy delivered, measured at the zone substation level, has declined by 0.37 per cent on average per year since 2016. We note energy delivered does not reflect consumption behind the meter, such as energy sourced from private solar PV.

Across the NEM, the following can be observed in the movement between categories of energy delivered since 2016:

- Energy delivered where time of use is not a determinant decreased by 2.63 per cent
- Peak energy delivered decreased by 1.37 per cent
- Off peak energy delivered increased by 4.44 per cent
- Shoulder period energy delivered decreased by 0.23 per cent
- Controlled load energy delivered decreased by 0.32 per cent.

Figure 5-11 Energy delivered by chargeable quantity (GWh) - All DNSPs



Source: Economic Benchmarking RIN, AER analysis.

5.4 Factors that may drive future uptake of cost reflective tariffs

This section describes some factors that might drive the future uptake of cost reflective tariffs, in addition to moving towards assigning end-use customers to cost reflective tariffs on an opt-out basis (discussed more in section 5.1).

We consider the success of smart meters and cost reflective tariffs go together given that smart meters enable cost reflective tariffs, and the value proposition of smart meters is much greater if cost reflective tariffs are used. This relationship is consistent with one of Newgate Research's key findings, in its report to the AEMC:[49]

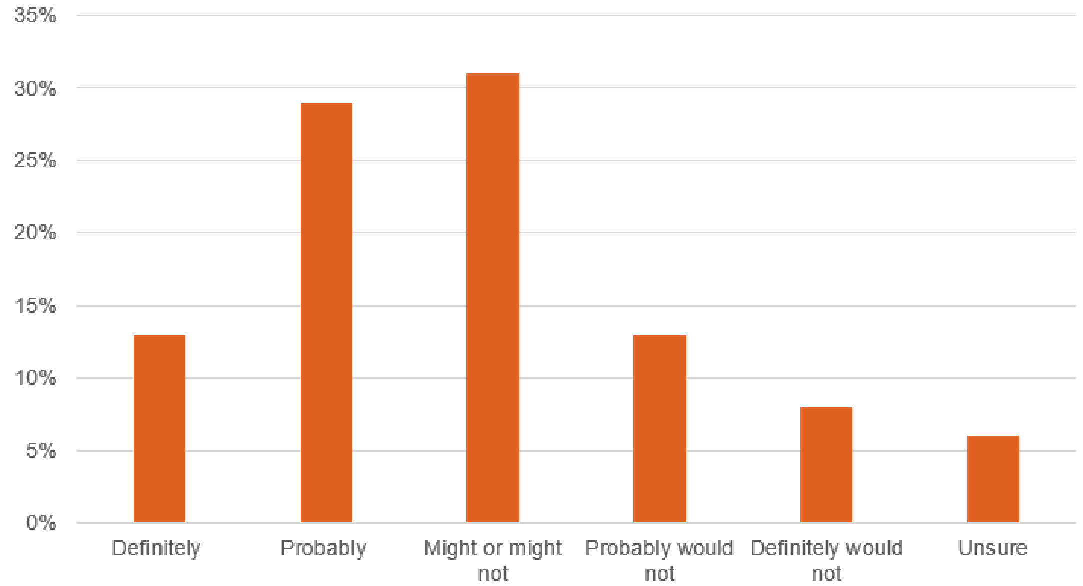
> *Critical to the successful smart meter installation roll out will be strategies to help [end-use] customers understand how to benefit from different pricing plans, specifically giving them clear information on how they can adapt their behaviour to take advantage of cheaper electricity during different times of the day.*

In forming this recommendation, Newgate Research observed many people in its focus groups were sceptical towards time of use tariffs and feared they would cost them more. Despite this, ECA's recent surveys found over 40 per cent of respondents said they would definitely or probably use smart appliances to reduce the cost of household energy – even though most respondents did not have smart devices installed at the time (Figure 5-12 and Figure 5-13). Notwithstanding there can be a gap between intentions and action, if consumer interest in using smart technologies to reduce energy bills converted into action, more consumers would theoretically benefit from (and therefore would want to) adopt cost reflective tariffs. That said, for this to play out, consumers would need to clearly understand how they can benefit from cost reflective tariffs— highlighting the importance of product/service innovation from industry, as well as clear information and leadership. Moreover, vulnerable consumers may be more limited to respond to price signals. Among other things, we are considering difficulties in responding to cost-reflective pricing as part of our consumer vulnerability strategy.[50]

49 Newgate Research, *AEMC metering review: An assessment of consumer experiences relating to smart electricity meters and their competitive roll out within the NEM*, September 2021.

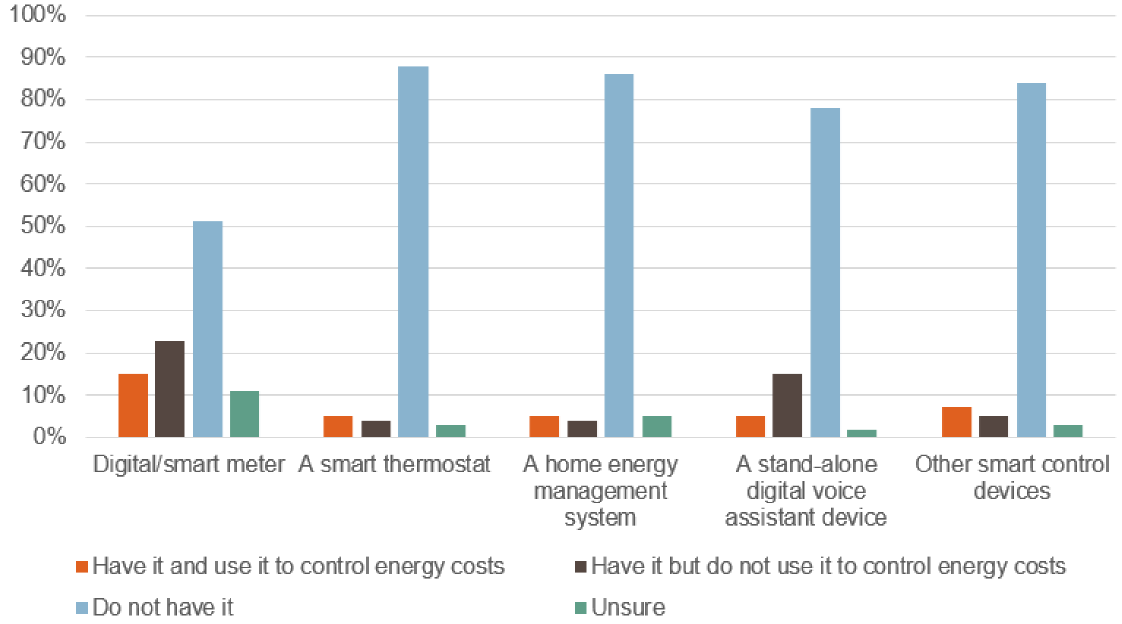
50 AER, *Consumer vulnerability strategy: Draft for consultation*, December 2021, p. 43.

Figure 5-12 How likely would you be to use smart appliances to reduce the cost of your household energy bills?



Source: Energy Consumers Australia, [Sentiment and behaviour surveys 2021](), accessed 4 April 2022.

Figure 5-13 Smart devices installed



Source: Energy Consumers Australia, *[Sentiment and behaviour surveys 2021]()*, accessed 4 April 2022.

Given the pivotal role of smart meters in enabling cost reflective tariffs, it is worth noting that the AEMC has recently recommenced its review the rules governing electricity meters. This review will assess both what might be needed to increase smart meter uptake and whether roles and responsibilities around metering currently under the NER need revision.[51]

51 AEMC, [Review announced into how electricity smart meters can deliver more customer benefits](), 2020.

5.5 Tariff trials

DNSPs introduced innovations in tariff design during the initial round of tariff structure statements. Higher rates of smart meter installation would increase the available data on individual energy consumption. Access to data could facilitate DNSPs development innovative tariff designs, consistent with the pricing principles under the NER to meet the changing needs of end-use customers.[52] However, access to individual usage data raises issues of protection of individual privacy. The AEMC will address privacy and data access as part of the development of a data access and exchange framework in its review of metering services.[53]

Table 5-1 presents DNSPs' tariff trials proposed in approved annual pricing proposals between 2018 to 2021.

Table 5-1 DNSP tariff trials from 2018 to 2021

<table>
<tr><th>DNSP– Tariff</th><th>Availability</th><th>Charging structure</th><th>Role of trial</th></tr>
<tr>
<td>Ergon Energy and Energex–

Residential lifestyle tariff</td>
<td>Introduced in 2018 to residential customers in the East zone that consume <100MWh per year</td>
<td>Volume charge ($/kWh)

Fixed charge ($/month) based on nominated band for usage during summer peak (4–9pm, Nov-Mar).
<table>
<tr><td>Band</td><td>1</td><td>2</td><td>3</td><td>4</td><td></td><td>5</td></tr>
<tr><td>kWh</td><td>0</td><td><5</td><td><10</td><td><15</td><td></td><td><20</td></tr>
</table>
Summer peak top-up ($/kWh) if band exceeded</td>
<td>The tariff linked the cost of using the network with daily usage during the summer peak. It was designed to be easier for end-use customers to understand than time-of-use tariffs and to smooth out the impacts of summer bill peaks associated with recovering seasonal costs.

The trial did not result in a new tariff being implemented.</td>
</tr>
<tr>
<td>SA Power Networks–

Trial tariff business annual agreed kVA demand</td>
<td>Introduced in 2018 to large business in Riverland (opt-in)</td>
<td>Fixed ($/day)

Usage ($/kWh)

Peak ($/kVA/day): based on 5 day average of highest 4 hour demand when Renmark's day ahead temperature is ≥40°C

Anytime maximum demand ($/kVA/day): based on highest 5 days 30 minute demand over the year</td>
<td>Shadowed the existing agreed demand tariff, but also tested concepts proposed for the next TSS. The trial enabled analysis of the effect on overall demand.

SA Power Networks incorporated features of the trial tariff in the new large business demand tariffs 2021</td>
</tr>
<tr>
<td>SA Power Networks–

Trial tariff residential time of use</td>
<td>Residential (default, participation optional)</td>
<td>Fixed ($/day)

Peak ($/kWh): 125% of flat rate over 6–10am and 3pm–1am

Solar sponge ($/kWh): 25% of flat rate over 10am–3pm</td>
<td>The trial tariff will help trial new technologies proposed by a technology provider and a retailer, for which the SA Government and Australian Renewable Energy Agency (ARENA) are considering approving funding.</td>
</tr>
</table>

52 NER, cl. 6.18.5.

53 AEMC, Directions paper: Review of the regulatory framework for metering services, 2021, p.12.

		Off-peak ($/kWh): 50% of flat rate over 1–6am	
SA Power Networks– Trial tariff residential single-rate with time of use controlled load	Residential (opt-in)	Fixed ($/day) Usage ($/kWh) with inclining block: 0–4MWh p.a.; >4MWh p.a. Peak controlled load: 125% of flat rate over 6–9:30am and 3:30–11:30pm Solar sponge controlled load: 25% of flat rate over 9:30am–3:30pm Off-peak controlled load: 50% of flat rate over 11:30pm–6:30am	The trial tariff is designed for use with interval meters where retailers and their metering co-ordinators have incentives to shift the flexible load via the interval meter controls to lower-load periods. The trial tariff will help trial new technologies that are being considered for funding approval from the SA Government and ARENA.
TasNetworks– TAS97: Residential low voltage DER; TAS98: Business low voltage DER	Introduced Dec 2018 to residential and small business customers with DER behind the meter	Both trial tariffs were time of use demand network tariffs with a daily flat charge and a demand change (c/kW), including both peak and off-peak rates	Trial supported TSS development and refining tariffs for Residential time of use demand (TAS87), Residential low voltage pay as you go time of use (TAS92), Residential low voltage time of use (TAS93), and Residential low voltage pay as you go (TAS101).
Powercor Australia– Newstead residential trial	Introduced Jul 2018 to residential customers around Newstead (opt-in)	$360 fixed charge (estimated 80% of network bill) $2/kW monthly demand charge based on maximum 30-minute demand measured 3–9pm on workdays.	Developed to support 'Renewable Newstead'–a project to test a locally generated renewable energy model within a community scale network. High fixed/low demand charge to encourage network utilisation in the unconstrained area.

Source: AER analysis of Ergon, *Annual pricing proposal distribution services for 1 July 2018 to 30 June 2019*; SA Power Networks, *Pricing proposal 2018/19*; TasNetworks, *Annual distribution pricing proposal 2018-19*; Powercor, *2018 pricing proposal*, SA Power Networks, *Pricing proposal 2019/20*; Energex, *Annual pricing proposal 2018–19*.

6 Focus area: Impact of extreme events on reliability, insurance, and network expenditure

Last year's report looked at seasonal reliability for DNSPs.[54] We found reliability varied in response to changes in seasons and weather. We also found seasonal patterns in reliability were consistent across jurisdictions and most feeder types. We considered major outages, or major event days through the 2019/20 bushfires, and concluded that further analysis was needed on the impact of these events.

In this section, we delve deeper into major events by considering their impact on reliability, insurance and NSPs' expenditure. Major event days are based on a mathematical calculation and represent unusual or extreme events that have occurred on an NSP's network. In Australia, extreme events or natural disasters come in many different forms and are forecast to become more prevalent in a changing climate.[55] Recent storms, cyclones, floods and bushfires have led to catastrophic outcomes for many people, including property loss and loss of life. These events have also resulted in financial costs and reliability losses to electricity consumers.

This section will look at the impact of these events on NSPs by:

- analysing total minutes of off supply experienced by customers across the 2014 to 2021 regulatory years, and how major event days are affecting supply interruptions on distribution networks (section 6.1)
- assessing how NSPs manage risks associated with major event days or extreme events and how these risks and risk management practices affect insurance costs (section 6.2)
- examining some of the costs of these events through cost pass through applications that NSPs have made due to natural disasters, noting that these applications would only represent a sub-set of these costs (section 6.3)
- discussing work into the future impact of extreme events (section 6.4)

Key findings:

- Large outages occurred on days in which a major event day occurred, with the highest magnitude outage (in terms of total minutes of off supply) occurring for Ausgrid, which serves many customers in a high-density geographical area.
- Outages are relatively minor and similar across the DNSPs when compared to outages experienced on major event days.
- NSPs can manage risks associated with extreme events by using four risk management strategies: prevention, mitigation, insurance, and self-insurance. An action that some NSPs have been undertaking is preventative capex and opex to mitigate against the impact of these extreme events. Even though preventative works can be net beneficial, we would not expect these would eliminate or substantially mitigate the cost impact of most extreme events or natural disasters.

54 AER, *Electricity network performance report*, 2021.

55 CSIRO and Bureau of Meteorology, *State of the Climate 2020*, 2020, accessed 20 April 2022.

- NSPs are also managing the risk of extreme events by using insurance or self-insurance. Given extreme events or natural disasters are forecast to be more likely[56], it may be harder and more costly for NSPs to insure themselves against those risks.
- Since 2012, all NSPs except Powerlink have natural disasters as a prescribed cost pass through event in the NER.[57] There have been eight pass throughs for natural disasters since 2014, which have cost $334.6 million. Cost pass throughs allow NSPs to recover these costs from customers by adjusting their forecast revenues, although would only capture a sub-set of the costs associated with these events.
- To mitigate against extreme events, DNSPs in the ACT, NSW, Tasmania and Northern Territory have started consulting with consumers on improving the resilience of their networks for their upcoming 2024–2029 regulatory determinations. The Victorian government is also undertaking a resilience review into DNSPs' preparedness and response to extreme events and storms. We expect network resilience to be a key feature of NSPs' upcoming regulatory proposals and have released a guidance note on how we will approach network resilience under the NER.[58]

6.1 Impact of extreme events on DNSP reliability

Network customers pay for reliability as a key service output and incur costs from electricity outages. These costs can be direct or indirect. Direct costs are through financial losses from lost productivity and business revenue. Indirect costs can be the reduced convenience, comfort, safety, and amenity that electricity provides.

When assessing the reliability performance of each DNSP, we consider sustained and momentary interruptions to calculate reliability measures detailed in our distribution reliability measures guideline and Figure 6-1.[59] These measures are used to determine the rewards and penalties for DNSPs as detailed in the STPIS.[60]

56 CSIRO and Bureau of Meteorology, *State of the Climate 2020*, 2020, accessed 20 April 2022.

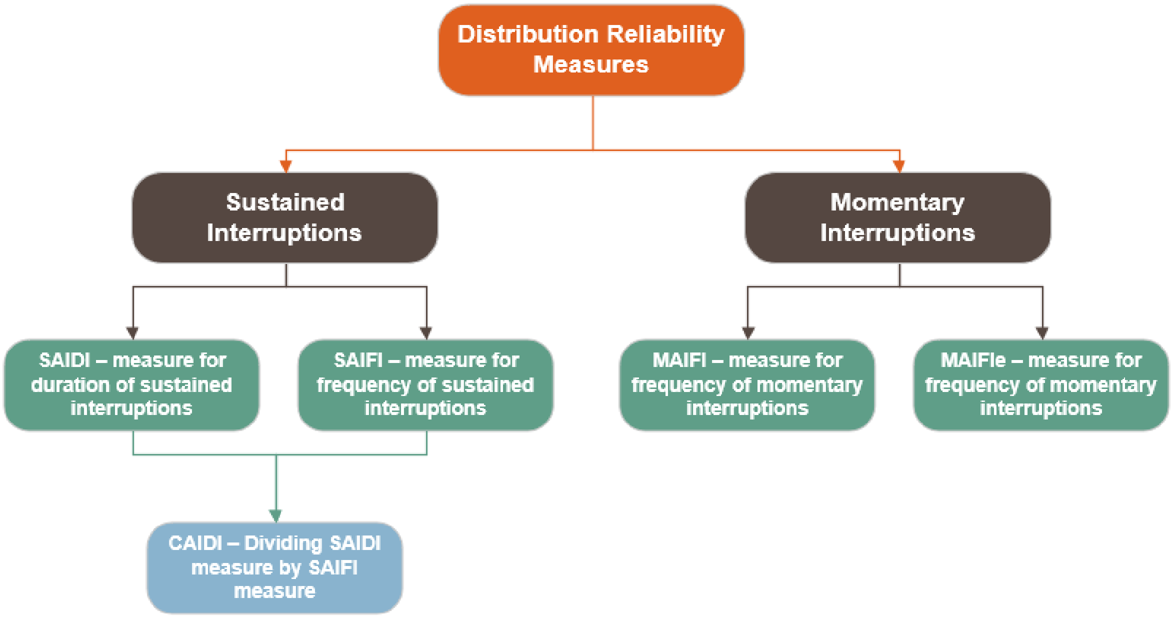
57 AEMC, *Rule determination: National electricity amendment (Cost pass through arrangements for network service providers) rule 2012*, 2012. A natural disaster event will apply to Powerlink for the 2022 to 2027 regulatory control period; see AER, *Powerlink Queensland Transmission Determination 2022 to 2027*, Final Decision, April 2022, p 84.

58 AER, *Network resilience: A note on key issues*, April 2022.

59 AER, *Distribution Reliability Measure Guideline - Version 1*, 2018, accessed 5 April 2022.

60 AER, *Electricity DNSPs STPIS version 2.0*, 2018. In contrast, the STPIS for TNSPs assesses reliability through a service, market impact and network impact component AER, *Electricity TNSP STPIS version 5 (corrected)*, 2015.

Figure 6-1 Reliability measures in the AER's reliability measures guideline[61]



Source: AER analysis.

When we calculate these reliability measures, observations can be excluded based on certain criteria. One exclusion criterion is where the DNSP's daily unplanned SAIDI exceeds the major event day boundary, where major event days are defined below.[62]

Calculation of major event days

Major event days are days in which the DNSP experiences interruptions beyond those normally expected (such as during severe weather, an extreme event, or a natural disaster) and are considered outliers when compared to day-to-day interruptions on a DNSP's network. Major event days are excluded when calculating incentive payments under the STPIS, and when benchmarking the DNSP's reliability in the annual benchmarking reports.[63]

A major event day is defined in the distribution reliability measures guideline and is calculated by the 2.5 beta method as defined in the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2012. This standard excludes natural events that are more than 2.5 standard deviations greater than the mean of the log normal distribution of five regulatory years' SAIDI data.[64] This is statistical method identifies days with unusually high unreliability and can be used across all DNSPs regardless of their size, geography or design.

61 Definitions for SAIDI, SAIFI, Momentary Average Interruption Frequency Index (MAIFI), Momentary Average Interruption Frequency Index event (MAIFIe) and Customer Average Interruption Duration Index (CAIDI) are in AER, *Distribution reliability measures guideline*, November 2918.

62 AER, *Distribution reliability measure guideline*, November 2018, p. 8.

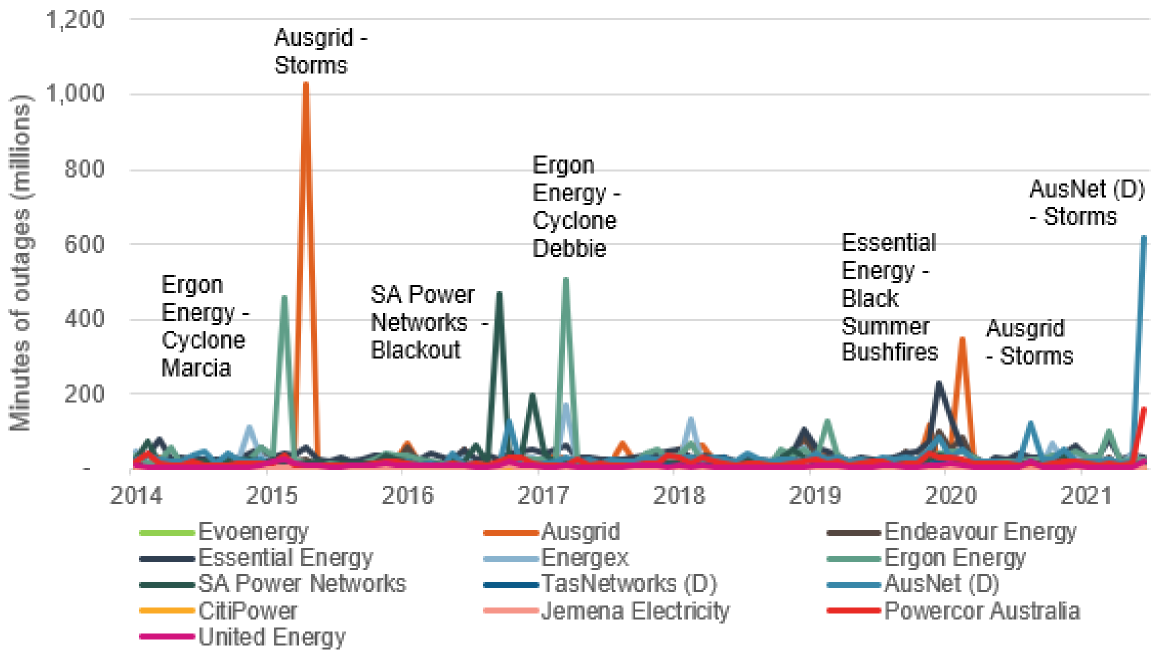
63 AEMC, *Final report - Review of distribution reliability measures*, September 2014, p. 24.

64 AEMC, *Final report - Review of distribution reliability measures*, September 2014–, pp. 24–27; AER, *Distribution reliability measure guideline*, November 2018, p. 7.

The threshold for a major event day is not static. This threshold changes each regulatory year, as it is calculated using reliability data from the NSP's five previous regulatory years. As such, if extreme events were to become more common, we would expect the threshold to gradually increase over time.

The hours of interrupted supply experienced by customers and the associated major event days from January 2014 to June 2021 are provided in Figure 6-2, where we have identified major events that resulted in over 200 minutes of off supply. Several natural disasters lead to cost pass throughs (identified in Figure 6-6) that fall below this threshold.

Figure 6-2 Minutes of outages and major event days 2014 to 2021[65]

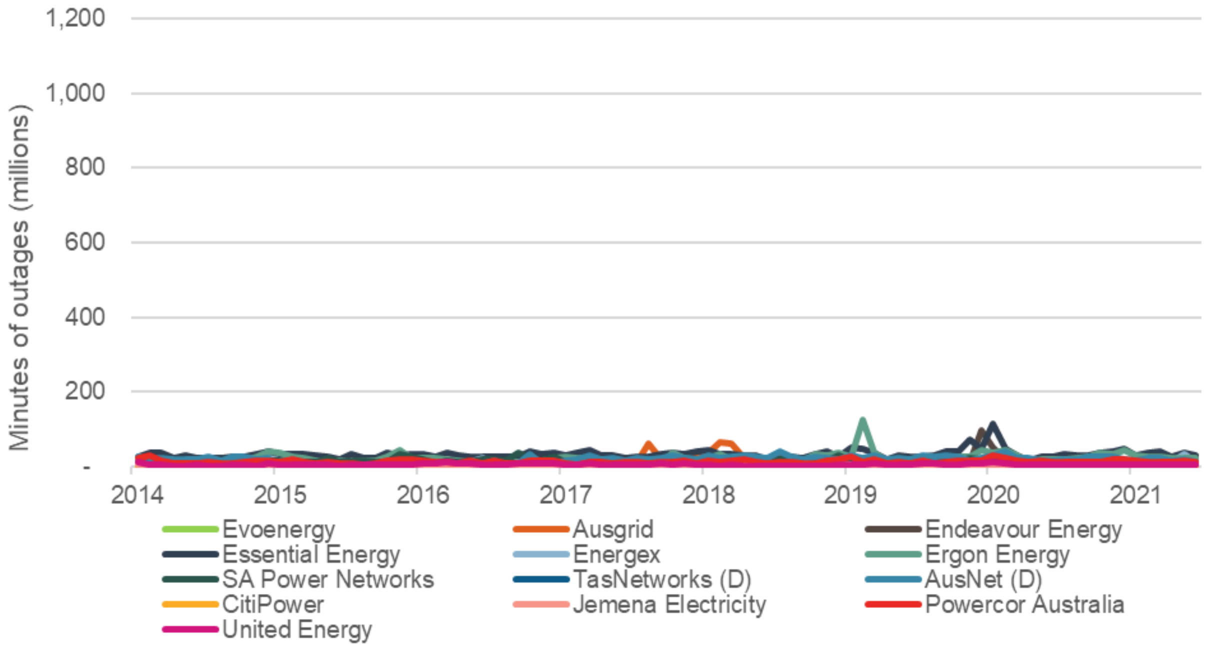


Source: Category Analysis RIN, AER analysis

Figure 6-2 shows large interruptions occurred on major event days, with Figure 6-3 showing the stark difference in interrupted supply experienced when major event days are removed.

65 We have not included Power & Water outage data in Figure 6-2 as we did not regulate them until the 2019 regulatory year. In March 2018 Cyclone Marcus caused significant interruptions to supply and outages for Power and Water's customers. The blackout in SA related to the Black System Event, which was triggered due to severe weather that damaged distribution and transmission network assets, however, a natural disaster did not occur. See AER, *Investigation report into South Australia's 2016 state-wide blackout*, accessed 9 June 2022.

Figure 6-3 Minutes of outages excluding major event days 2014 to 2021



Source: Category Analysis RIN, AER analysis

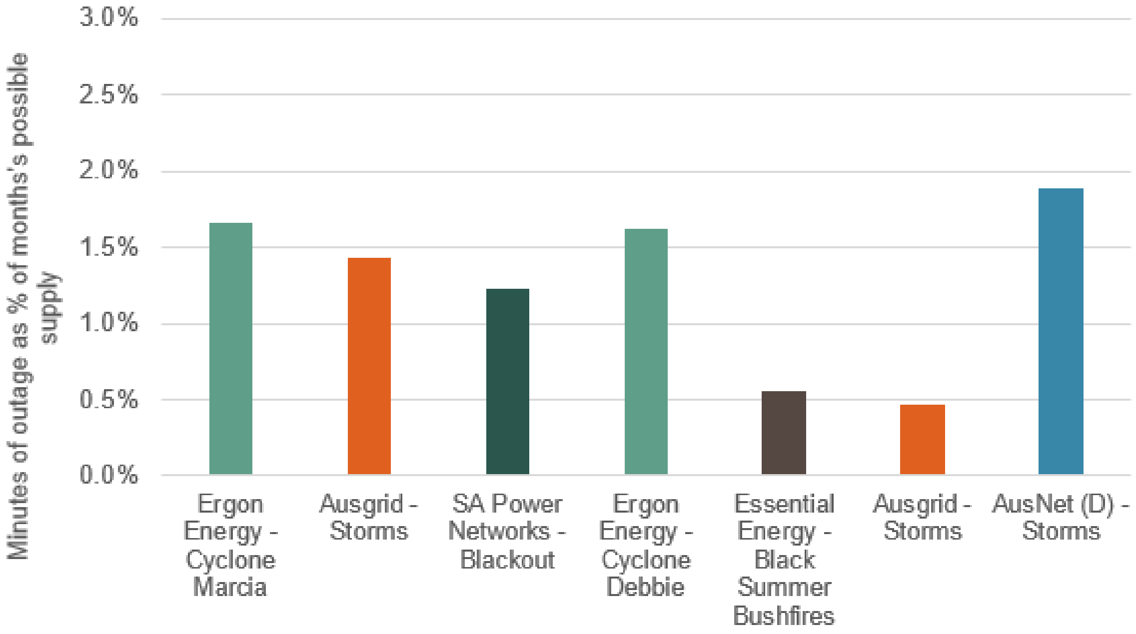
Figure 6-2 and Figure 6-3 highlight that major event days have a material effect on the magnitude of specific interruptions that customers experience. With these outliers removed, the interruptions that customers experience are relatively similar across the DNSPs in comparison to the variation in outages experienced on major event days.

When assessing the impact of the extreme events, the most interrupted hours of supply that customers experienced occurred when storms affected Ausgrid in April 2015. This is expected as Ausgrid serves the largest number of customers, and its network operates in a high-density geographical area. Therefore, one short significant event can lead to an electricity outage affecting a large number of customers.

This contrasts with Cyclone Marcia and Debbie and the Black Summer bushfires, which did not have the same high level of interruptions that customers experienced, despite these events causing longer and wider electricity outages for some consumers. This is due to the lower density in the rural geographical zones where Ergon Energy and Essential Energy provide network services.

When assessing the outages as a percentage of the total month’s supply of electricity, outages vary between approximately 0.5% to 2.0%, as noted in Figure 6-4.

Figure 6-4 Minutes of outages as percentage of month's electricity supply



Source: Category Analysis RIN, AER analysis

Due to their nature, major event days or extreme events often damage DNSP network assets. Physical damage requires DNSPs to replace network assets and incur additional operational costs to provide short term supply, coordinate the restoration of the network and inform consumers on their progress.

TNSPs' network assets can also be damaged by major or extreme events, which require immediate expenditure to maintain the transmission of electricity to consumers.

This physical damage and associated operating costs may result in NSPs incurring expenditure that was not provided for in their regulatory allowances. This potential for additional costs from major event days is a risk for NSPs, which they need to manage when operating their networks.

6.2 NSPs' risk management and insurance costs

NSPs or any business can undertake several strategies to manage risk.[66] Table 6-1 summarises the key risk management strategies, and our assessment of how these apply to NSPs.

Table 6-1 Risk management strategies and how an NSP manages risk

Risk management strategy	How can a NSP manage risk?
Prevention Risk avoidance: avoiding the risk	An NSP is unable to realistically prevent an extreme event or natural disaster from occurring.
Mitigation Risk reduction: Reducing the negative impact or probability of the risk	An NSP can sometimes mitigate the occurrence of an extreme event or natural disaster, such as through bushfire preventative capex and opex. However, most natural disasters are outside NSPs' control. In such cases, preventative expenditure can still have net economic benefits by mitigating the negative impact of these events (for example, major storms are less likely to have a negative impact on cables that have been undergrounded). Nevertheless, the extreme nature of natural disasters means preventative expenditure would not necessarily eliminate or substantially mitigate the cost impact of natural disasters.
Insurance Risk transference: Transferring the risk to another party via payment of a fair premium	NSPs might be able to obtain insurance against certain extreme events or natural disasters.
Self-insurance Risk acceptance: Putting money aside to manage the costs associated with risk events	Self-insurance can be a prudent option for risks that the NSP has the capacity and appetite to bear. The relative infrequency and high costs of an extreme event or natural disaster can prevent self-insurance from being a viable option.

Source: AER analysis.

Risk management strategies for businesses and consumers

Table 6-1 does not include the risk management strategies for businesses and consumers in relation to an outage from an extreme event.

Outages from extreme events could lead to a loss of productivity and revenues for many businesses. The impact of extreme events on essential services such as healthcare facilities and hospitals is even more acute, as uninterrupted electricity is critical in providing the necessary care to patients.

To mitigate against the impact of outages, these business and essential services can use backup generators to maintain electricity supply throughout an extreme event. However, the cost to residential or small business consumers of investing in backup generators to provide electricity supply throughout extreme events can be considerable. Further, there are considerable carbon dioxide risks associated with back-up diesel generators, especially if the

66 EY, *Review of regulatory treatment of risk - Ausgrid, Endeavour Energy and Essential Energy*, April 2014, pp. 5–7.

generator is portable, and is operated in an enclosed area.[67] Both the cost and health risks associated with generators will reduce the likelihood of residential and small business consumers being able to use the same methods to maintain supply throughout an extreme event. This will often leave these consumers unable to undertake any effective or realistic risk management strategies to prevent outages from extreme events.

Jurisdictional Guaranteed Service Level (GSL) schemes result in payments to customers when certain service standards fall outside defined levels. While GSLs can sometimes apply to outages, they are not designed to compensate customers for their losses. As such, GSLs provide for inconvenience payments rather than risk management.

Energy Networks Australia (ENA) highlighted the impact of extreme events or natural disasters on insurance risk management strategies and the changing landscape of the insurance market in its submission to the *Royal Commission into National Natural Disaster Arrangements*.[68] ENA noted that the increase in natural catastrophic events was driving significant loss claims activity in local and global markets. ENA submitted insurance coverage was difficult for NSPs to obtain as increasing loss claims were causing the insurance capacity market to reduce and existing insurers to increase their premiums. ENA's submission noted that because NSPs' risks and volatility of claims are complex, they must be underwritten by specialist insurers that often operate outside of Australia. These global insurers are seeing an increased number and value of catastrophic events worldwide, resulting in significant insurance claims and pay-outs.[69]

These events can affect insurance costs, which we provide for in NSPs' opex allowances set every reset cycle (typically five years). Due to recent extreme events and natural disasters, both internationally and within Australia, and conditions in insurance markets, there may be material changes in NSPs' insurance coverage and premiums going forward. These changes may have a material impact on the costs incurred by NSPs during their regulatory control periods.[70]

NSPs can, and have, sought step changes to their opex allowance to reflect forecast increases in insurance premium costs in upcoming regulatory control periods through their regulatory proposals. Under the NER, TNSPs can also seek, within a regulatory period, a cost pass through for insurance premium costs that are materially higher or lower than the premiums included in their opex allowance. The same pass through is not available to DNSPs.

What is a pass through event?

Pass through events are a mechanism within the regulatory framework prescribed in the National Electricity Rules (NER) that require us to adjust the allowed building block revenues in

67 Victoria State Department of Health, *Power blackouts – generators, alternative appliances and carbon monoxide*, accessed 9 June 2022.

68 ENA, Submission –*Royal Commission into National Natural Disaster Arrangements*, April 2020, pp. 3–4.

69 ENA, Submission –*Royal Commission into National Natural Disaster Arrangements*, April 2020, pp. 3–4.

70 TNSPs able to seek a cost pass through for these increased costs within a regulatory control period.

a regulatory determination.[71] These adjustments can be positive (to increase forecast revenues) or negative (to reduce forecast revenues).

The cost pass through events prescribed for NSPs in the NER is provided in Table 6-2. Costs associated with these events must be material in the sense they exceed one per cent of the allowed revenue an NSP can earn in that regulatory year.

Table 6-2 NSP cost pass through events under the NER

All electricity NSPs	Distribution only	Transmission only
Regulatory change event	Retailer insolvency event	An insurance event
Service standard event		An inertia shortfall or fault level event
Tax change event		Network support
Events specified in a regulatory determination as a pass through event for the regulatory control period		

Source: AER analysis of NER clauses 6.6.1(a1), 6A.7.3(a1) and 6A.7.2.

Table 6-2 notes that during the regulatory determination process, NSPs can propose pass through events to apply for their regulatory control period. Each current regulatory determination allows pass throughs for an insurance coverage or insurance cap event.[72]

We have been transitioning NSPs, as a part of our regulatory determination processes, from being able to pass through costs for insurance cap events to being able to do this for insurance coverage events, with the difference explained in Table 6-3.

This has been driven by possible changes in the relevant insurance liability markets beyond the NSP's control. This could result in a tightening insurance market, causing NSPs to have gaps in their insurance cover, or lower insurance caps. Pass throughs for insurance coverage events also require us to assess the efficiency and prudency of the NSP's insurance policies, which would include examining their procurement process.

Guiding principles on how we would make such an assessment are outlined in our guidance note on insurance coverage pass through events.[73]

71 Under NER cl 6.6.1 for DNSPs and NER cl 6A.7.3 for TNSPs.

72 Available in each pass-through event attachment published alongside the relevant AER regulatory determination. See the 'Determinations & Access Arrangements' page of our website.

73 AER, *Final guidance note - Insurance coverage cost pass through event*, 2021.

Table 6-3 Insurance coverage versus insurance cap pass through events

	Insurance coverage events	Insurance cap events
Currently applies to	Queensland, South Australian and Victorian DNSPs, AusNet (T)	ACT, NSW, Tasmanian and Northern Territory DNSPs and TNSPs except AusNet (T)
When does it occur?	• IF an NSP claims and receive payments under a relevant insurance policy or could have claimed under a relevant insurance policy but for changed circumstances • AND the NSP incurs increased costs that are beyond the relevant policy limit or are unrecoverable under that policy but for changed circumstances • AND changed circumstances are due to movements in the relevant insurance liability market beyond the NSP's control such that it is no longer possible for the NSP to take out insure at all or on reasonable terms • AND these costs materially increase the costs in providing core regulated services	• IF an NSP makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy • AND the NSP incurs costs beyond the relevant policy limit • AND the costs beyond the relevant policy limit materially increase the costs in providing core regulated services.

Current regulatory determinations also include an insurance credit risk event for all NSPs except for TasNetworks (distribution and transmission).[74] This event relates to the costs NSPs will incur if their insurer becomes insolvent. Moreover, all current regulatory determinations except for Powerlink include a natural disaster pass through event.[75]

From the start of the 2015 regulatory year up until the 2021 regulatory year-end, no NSP has applied for a cost pass through for an insurance cap, insurance coverage or insurance credit risk event. However, on 16 December 2021, ElectraNet applied for a cost pass through of $3.4 million ($nominal) in relation to insurance premium costs for the 2022 regulatory year. In its application, ElectraNet noted the position for insurance buyers was substantially less favourable than in March 2017.[76]

6.3 Impact of extreme events of NSP expenditure and cost pass throughs

Extreme events or natural disasters can damage network assets. This can result in capital costs to repair and replace network assets, and operating costs to expedite the restoration of the network.

74 Available in each pass-through event attachment published alongside the relevant AER regulatory determination. See the 'Determinations & Access Arrangements' page of our website.

75 See the pass-through event attachments published alongside our regulatory determinations on our website. For Powerlink, see: AER, *Final decision - Powerlink regulatory determination 2017–2022 - Attachment 13: Pass-through events*, 2017, pp. 6–8. A natural disaster event will apply to Powerlink for the 2022 to 2027 regulatory control period; see AER, *Powerlink Queensland transmission determination 2022 to 2027*, Final decision, April 2022, p. 84.

76 ElectraNet, *Insurance costs 2021-2022 - Cost pass through application*, December 2021, p. 3. The application was pursuant to the insurance pass through under NER cl 6A.7.3(a1)(4).

When the AEMC was considering whether to codify natural disaster cost pass throughs in the NER (which it did not), it considered cost pass throughs should be the last option available to NSPs to manage risks relating to costs associated with providing core regulated services.[77] However, the AEMC also considered NSPs should be able to recover the efficient costs associated with events outside their reasonable control. The AEMC consequently gave NSPs the ability to nominate pass through events and for the AER to decide whether to accept those events according to a set of nominated cost through considerations. It noted that cost pass throughs should, where appropriate, provide:[78]

- flexibility for changing circumstances;
- direct application to the individual circumstances of each NSP; and
- encouragement for NSPs to utilise market-based mechanisms.

Allocation of risk between NSPs and consumers

In making its decision on whether to include natural disaster cost pass throughs in the NER, the AEMC considered the issue of how risks should be allocated between NSPs and consumers. The decision aimed to appropriately balance risks between NSPs (to recover costs and attract sufficient investment) and consumers (to ensure costs are no more than necessary).[79]

The AEMC considered a cost pass through should only be accepted when it is the least inefficient option and event avoidance, mitigation, commercial insurance, and self-insurance are found to be inappropriate. In determining a cost pass through application, the AER requires NSPs to mitigate and reduce their exposure to natural disaster events. However, expenditure incurred to eliminate risks associated with natural disaster events is expected to be imprudent or inefficient. Due to this, balancing the risk between NSPs and consumers should ideally increase the likelihood that prices reflect prudent and efficient costs.

In a changing climate, where natural disasters are more prevalent, natural disaster cost pass throughs will be more likely. Costs incurred for natural disasters above the cost pass through materiality threshold and approved by the AER will increase network service costs. Whether there is equilibrium in the risk and cost for natural disasters between NSPs and consumers is an important question in a changing climate.

77 AEMC, *Rule Determination - National Electricity Amendment (Cost pass through arrangements for network service providers) Rule 2012*, 2012, p i.

78 The AEMC's considerations are set out in: AEMC, *Rule Determination - National Electricity Amendment (Cost pass through arrangements for network service providers) Rule 2012,* 2012, pp. 9-10.

79 AEMC, *Rule Determination - National Electricity Amendment (Cost pass through arrangements for network service providers) Rule 2012*, 2012, p 20.

As noted in section 6.2, all current regulatory determinations except for Powerlink[80] include a natural disaster pass through event.[81] While slightly different definitions have been used in regulatory determinations, Figure 6-5 provides an illustration of a natural disaster definition we have allowed.

Figure 6-5 Definition of a natural disaster for cost pass through

Any natural disaster* that occurs during the regulatory control period that changes the costs to the NSP in providing direct control services, provided the…event was:

A consequence or an act or omission that was necessary for the NSP to comply with a regulatory obligation or requirement or with an applicable regulatory instrument

OR

Not a consequence of any other act or omission of the NSP

In assessing the pass through, the AER will have regard to (amongst other things):

- Whether the NSP had insurance for the event
- The level of insurance an efficient and prudent NSP would obtain for the respective event

** including but not limited to cyclone, fire, flood or earthquake*

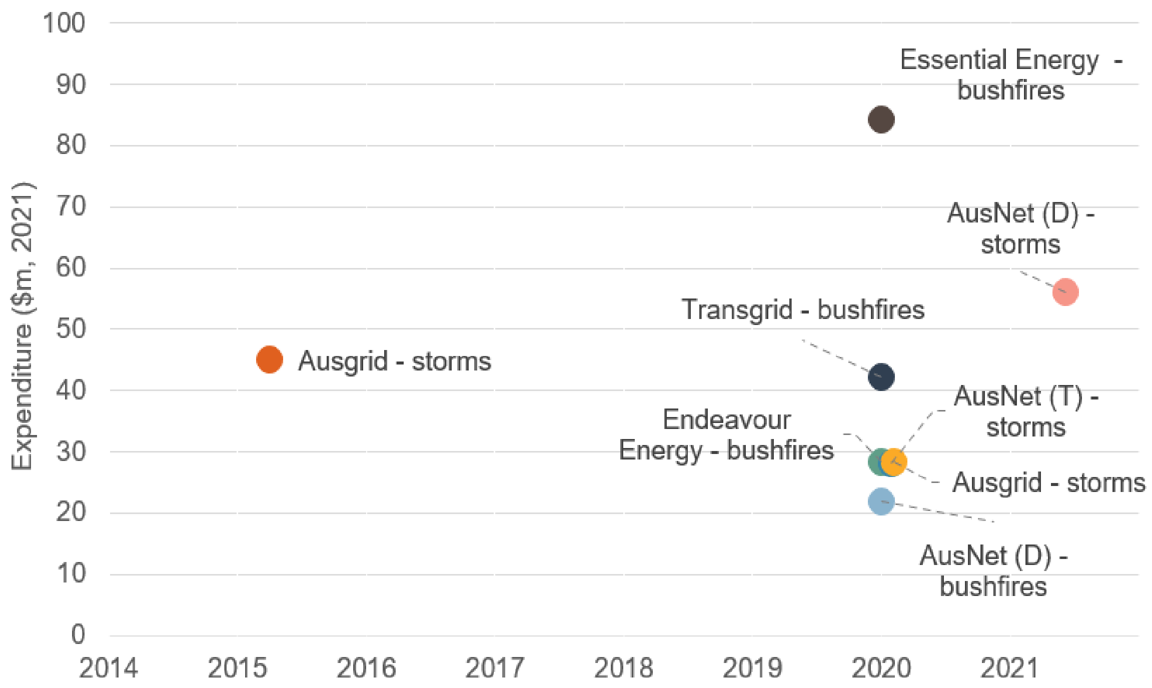
Source: Adapted from AER, Final decision – AusNet (D) regulatory determination 2021-2026 – Attachment 15 Pass-through events, 2021.

From 1 January 2014 to 30 June 2021, we approved eight applications to pass natural disaster-related costs through to network charges. The cumulative total of these costs was $334.6 million as shown in Figure 6-6.

80 Powerlink did not propose a natural disaster pass through in its proposal for its 2017–2022 regulatory determination. In its proposal (p. 73), Powerlink proposed a combination of insurance policies, self-insurance and cost pass through arrangements to manage exogenous risks associated with operating its network.

81 See the pass-through event attachments published alongside our regulatory determinations on our website. For Powerlink, see: AER, *Final decision – Powerlink regulatory determination 2017–2022, Attachment 13: Pass-through events*, 2017, pp 6-8.

Figure 6-6 Natural disaster cost pass through applications approved



Source: Cost pass through applications, AER analysis.

In comparing these cost pass throughs against the major event days included in Figure 6-2, the Black System Event,[82] Cyclone Marcia and Debbie and Cyclone Marcus are not included. Power and Water's first regulatory determination started on 1 July 2019, which would prevent a cost pass through for Cyclone Marcus in 2018 from being approved. The costs associated with these other major events may have been below the cost pass through materiality threshold,[83] or the NSPs may have chosen not to apply for a pass through.[84]

When assessing an NSP's cost pass through application driven by a natural disaster, NER clauses 6.6.1 and 6A.7.3 provide guidance. This includes that the assessment involve whether a natural disaster event has occurred, whether the event could not be prevented or mitigated and to assess the NSP's information in relation to the costs incurred due to the natural disaster.

NSPs recover pass through costs from consumers in parts:

- Recovering more revenue from customers in the following regulatory years in accordance with our cost pass through determination, through adjusting the forecast revenues from the building block determination. This includes recalculating the allowances for opex, return of capital, return on capital and taxation costs. We have previously considered consumer preferences when determining the timing for revenue recovery, including in decisions for

82 The Black System Event was triggered due to severe weather that damaged distribution and transmission network assets, however, a natural disaster did not occur. For more information, see AER, *Investigation report into South Australia's 2016 state-wide blackout*, accessed 9 June 2022.

83 The NER defines 'materially' is when the event results in the NSP incurs or is likely to incur materially higher or lower costs as result of the event, and the costs exceeds 1% of the annual revenue requirement for the NSP for the regulatory year (Chapter 10 - Glossary).

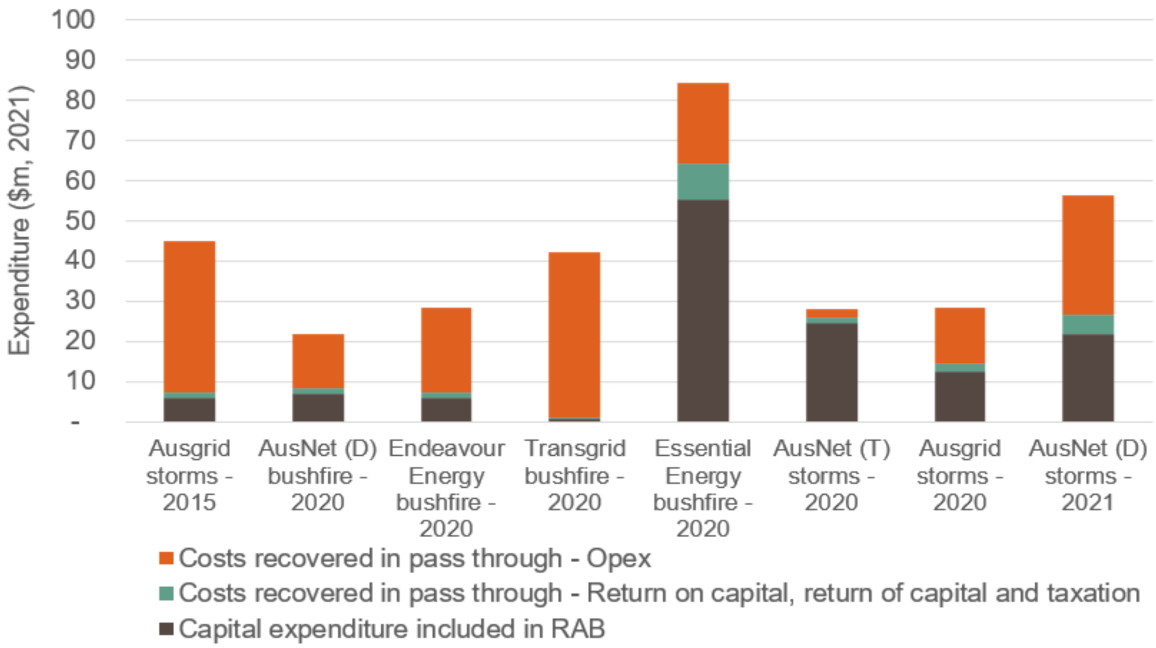
84 Energy Queensland shareholders have recently not endorsed the use of a cost-pass throughs due to the impact on customer pricing. Energy Queensland, *RP–TSS working group – Building blocks summary report*, 25 June 2018, p. 6.

Essential Energy (two years), Ausnet Services (five years) and Endeavour Energy (three years).[85]

- Including more capex in their RAB in the same manner as all other capex. This increased capex is not recovered from customers in the cost pass through application, but rather in future regulatory years though the return of capital building block. This is the capex included in RAB in Figure 6-7.

Figure 6-7 provides the breakdown between these two types of costs for each of the eight approved natural disaster pass throughs.

Figure 6-7 Natural disaster cost pass through applications costs



Source: Cost pass through applications, AER analysis.

Figure 6-7 highlights how costs can differ for each natural disaster. Essential Energy's cost pass through application for the 2020 bushfires resulted in a relatively large proportion of capex being included in the RAB.[86] This indicates a large proportion of the costs were due to bushfires damaging Essential Energy's network assets, requiring replacement capex rather than opex to restore the electricity supply. This differs from TransGrid's application for the 2020 bushfires, where most of the costs were opex for network safety and restoration, network repair and vegetation management and access activities.[87]

85 AER, *Determination: Cost pass through – Essential Energy's 2019–20 bushfire natural disaster events*, 2022, p. 18; AER, *Decision: Cost pass through – AusNet Services' 2019-20 bushfire natural disaster event*, November 2020, pp. 14–15; AER, *Decision: Cost pass through - Endeavour Energy's 2019-20 bushfire natural disaster event*, February 2021, p. 15.

86 AER, *Determination - Cost pass through Essential Energy's 2019-20 bushfire natural disaster events*, March 2022, p. 5.

87 TransGrid, *TransGrid - Cost pass through application 2019-20 Bushfire season*, November 2020, p. 13.

6.4 Future impact of major event days and extreme events

In the 2020 and 2021 regulatory years, there were seven cost pass throughs for natural disasters. Although after the completion of the 2021 regulatory year, the February and March 2022 floods in Queensland and NSW would have also damaged network assets in the geographical areas affected.

ENA's recent report discussed the likelihood of more extreme events.[88] ENA's report cites the 'State of the Climate 2020' in noting there was to be a continued increase in air temperatures, harsher and longer fire seasons, longer droughts and more intense storms and cyclones.[89]

ENA's report highlights that these events will affect the operation of the electricity networks and the supply of electricity to consumers and businesses as they will:[90]

- reduce network capacity
- damage network assets
- increase outages and flashovers
- increase operational, repair and maintenance costs
- increase demand
- disrupt supply.

A future with more extreme events will result in more outages for consumers and higher prices, as NSPs need to replace damaged network assets (capex), increase their operating costs to restore supply (opex) and mitigate against the impact of other extreme events. One method to mitigate against the impact of extreme events is to improve the resilience of the electricity networks.

In January 2022, Ausgrid, Endeavour Energy, Essential Energy, TasNetworks (distribution), Evoenergy and Power and Water wrote a collaboration paper on network resilience for their upcoming 2024–2029 regulatory determinations.[91] This paper will be followed by public engagement processes to seek stakeholder feedback on factors surrounding network resilience in a changing climate.

Further, following the storm event that impacted Victorian electricity networks (particularly AusNet's distribution network) in June 2021, the Victorian Minister for Energy, Environment and Climate Change established the Electricity distribution network resilience review expert panel (the Expert Panel) to review the role of the Victorian NSPs. This review also considered further storm events in October 2021 and examined how to improve DNSPs' preparedness and response to prolonged power outages arising from storms and extreme events, as well as strengthening community resilience to prolonged power outages. [92]

88 ENA, *Electricity Networks: A guide to climate change and its likely effects*, 2022, p. 6.

89 Bureau of Meteorology and CSIRO, *State of the Climate 2020*, 2020, p. 3.

90 ENA, *Electricity Networks: A guide to climate change and its likely effects*, 2022, p. 7.

91 Ausgrid et al, *Network resilience - 2022 collaboration paper on network resilience*, 2022, p. i.

92 Engage Victoria, *Electricity and gas network safety review*, accessed 13 June 2022.

The collaboration paper between DNSPs in the ACT, NSW, Tasmania and Northern Territory and the review by the Victorian government,[93] do not solely involve improving the capital infrastructure of electricity networks. Rather, these also involve improving how communities can prepare, plan and respond to natural disasters and how both NSPs and governments can support community resilience.

Recently we have published a note on the key issues for weather-related network resilience.[94] This note considers four questions central to the ongoing discussion around network resilience:

- What is network resilience?
- Does the NER accommodate funding related to network resilience?
- If the NER does accommodate network resilience funding, what evidence should NSPs provide to demonstrate that the funding is in the long-term interests of consumers?
- What is a NSPs role in supporting community resilience?

We have developed this note to encourage broader discussions around network resilience, and to assist NSPs, consumer groups and advocates understand how resilience-related funding would be treated under the NER. This will be important for upcoming regulatory determinations, as we expect issues surrounding network resilience will be a key feature for each NSP’s upcoming regulatory determination.

93 The Department of Environment, Land, Water and Planning (DELWP) is the responsible department for the review.

94 AER, *Network resilience: A note on key issues*, April 2022.

7 Network safety information

Safety forms part of the national electricity objective (NEO). The NEO is about promoting efficient investment in, and efficient operation and use of, electricity services for the long-term interests of electricity consumers. This is where consumer interest is with respect to several outcomes, including the safety of electricity supply and national electricity system.

NSPs are responsible for safely operating their networks. Legislative safety obligations recognise the limitations of risk elimination, and typically support mitigating risk to a level as low as reasonably practicable (ALARP). The ALARP principle aims to reduce risk where the cost of reducing risk should not be grossly disproportionate to the benefit gained or where the solution is impracticable to implement. Legislative obligations sometimes support mitigating safety risks as far as practicable (AFAP), which provides a higher threshold.[95]

The incentive framework recognises NSPs are best placed to decide how to use their allowed revenues to manage their networks and associated risks. However, our revenue decisions must reasonably allow NSPs to operate their networks consistently with their legislative obligations, which include safety obligations. Reporting on network safety can help us better understand network safety when making revenue decisions and allows us to monitor whether NSPs benefiting from spending less than their allowed revenues are not doing so at the expense of providing for the safe supply of electricity.

On this basis, our 2021 electricity network performance report explored options for adding network safety to our annual network performance reporting. In 2021, we engaged with several jurisdictional technical and safety regulators, surveyed publicly available reports on network safety, and made a reference list to relevant reports. We advised that our future reports would continue to summarise available reporting and data from the jurisdictional regulators as an information resource for stakeholders. Section 7.1 provides this summary.

While synthesising publicly available information is useful, we also recognise that additional work is required if we are to better understand how and why different safety activities, outcomes and trends compare across NSPs, jurisdictions and time. Such comparisons can help us to better understand safety performance and associated expenditure requirements. However, such comparisons are difficult to interpret accurately and require measures to be well-defined and consistently reported. We are therefore considering what might be required to report data on a more comparable basis, noting that it might still only be reasonable to compare an NSP's performance against itself over time.

7.1 Summary of information available from jurisdictional reporting

Jurisdictional regulators monitor NSP compliance with safety obligations in the relevant jurisdictional legislation, licence conditions and standards. They also audit NSP[96] compliance with licence conditions and monitor whether their Electricity Network Safety Management Systems

95 For example, see the Victorian *Electricity Safety Act 1998* (no. 25 of 1998), accessed 29 March 2022.

96 Jurisdictional regulators use the term 'network operator', which we have interchanged for the term, 'network service provider'.

(ENSMS) are developed to a minimum standard.[97] Meeting these standards includes, among other things, identifying and evaluating risk control measures and treatments.

Jurisdictional regulators often collect data on safety related performance measures to complement their audit work. This includes information on notifiable events and activities related to the safe operation of the network. This information allows for monitoring trends in key statistics, with the potential to identify areas of future audit activity.

We have reviewed publicly available data reported on electricity network safety with the aim of:

- providing a consolidated reference list as a resource for others (Table 7-1)
- working out how we can draw on available data to avoid unnecessary duplication of regulatory reporting requirements in the future
- identifying any trends or concerns

Table 7-1 Sources of publicly available network safety data

Jurisdiction	Published reports
NSW	NSPs publish annual reports of ENSMS data on their websites.[98] The Independent Pricing and Regulatory Tribunal (IPART) also publishes annual reports detailing compliance outcomes, events and treatments.[99]
ACT	The Utilities Technical Regulator (UTR) publishes annual reports on its website that detail compliance outcomes, events and treatments.[100] Reports cover Evoenergy and TransGrid.
Victoria	Energy Safe Victoria (ESV) publishes annual reports detailing compliance outcomes, events, and treatments.[101] Each DNSP also submits fire-start reports to the AER under the F-factor scheme.[102]
QLD	Annual reports from Powerlink and Energy Queensland (including data on Ergon Energy and Energex).[103] Queensland's Electrical Safety Office does not publish their annual compliance reports.
SA	SA Power Networks and ElectraNet report results of audits against their Safety, Reliability, Maintenance and Technical Management Plans to the Office of the Technical Regulator (OTR). The OTR then publishes technical regulator annual reports detailing key performance indicators and compliance outcomes, events and treatments.[104]

97 AS 5577 refers to the Australian Standard AS 5577 - 2013 Electricity Network Safety Management Systems.

98 Ausgrid, *Annual ENSMS report*, November 2021; Endeavour Energy, *Annual ENSMS performance report 1 July 2020 - 30 June 2021*, 2021; Essential Energy, *ENSMS performance and bushfire preparedness report*, October 2021; Transgrid, *Annual safety performance and bushfire preparedness report 2020/21*.

99 IPART, *Annual compliance report - Energy network operator compliance during 2020-21*, 2021.

100 Access Canberra, *Utilities Technical Regulation: Related resources*, accessed 28 March 2022.

101 Energy Safe Victoria, *Safety performance report on Victorian electricity networks*, 2021.

102 We released 2019-20 in June 2021 for AusNet Services (D), CitiPower, Jemena Electricity, Powercor and United Energy on our website. The F-factor scheme does not apply to AusNet Services (T).

103 Energy Queensland, *Annual report and other documents*, accessed 29 March 2022; Powerlink, *Reports*, accessed 29 March 2022.

104 Government of SA Department of Energy and Mining, *Annual Reports* - *'Technical regulator annual report'*, Accessed 29 March 2022.

Jurisdiction	Published reports
TAS	TasNetworks (distribution and transmission) publishes annual reports, which include information on significant incidents, reportable incidents and total recordable injury frequency rates.[105] The Office of the Tasmanian Regulator's annual performance reports do not cover safety performance.
NT	Power and Water publishes annual reports, which include lost time injury frequency rates.[106] The Electricity Safety Regulator (within NT WorkSafe) publishes annual reports, although its remit excludes electrical infrastructure owned and operated by electricity entities.[107]

Source: AER analysis.

When analysing the available data and consulting with jurisdictional regulators, we identified the following considerations for drawing on currently available data for performance reporting:

- Available information varies between jurisdictions, as well as the performance metrics collected. Our analysis shows there is very little overlap in the specific metrics reported in different jurisdictions. As Table 7-2 shows, DNSPs and TNSPs within the one jurisdiction might report different measures (for example, SA and ACT).
- Even when measures seem similar, they may be measuring different things. For instance, reportable incidents in Tasmania will differ from notifiable incidents in the ACT insofar as those jurisdictions have different incident reporting requirements. Also, some jurisdictions do not define measures strictly, such that comparisons between NSPs within the one jurisdiction may not be like-for-like.
- Currently available data could still be useful for monitoring trends in an individual NSP's performance over time, although this would not necessarily lend itself well to NEM-wide network performance reporting.
- While statistical performance metrics have value, richer information is often found in business cases and network management plans.
- Some data cannot be made available due to confidentiality concerns, privacy provisions or other legislative requirements.
- Some metrics, such as reported safety incidences are often low, which makes it difficult to monitor trends. This tends to affect lagging indicators rather than leading indicators.
- Jurisdictional regulators generally find leading indicators more useful than lagging indicators as a poor safety decision may produce an incident decades later. Nevertheless, lagging indicators are useful for understanding the current state of the network and to monitor issues of public interest.

Table 7-2 summarises the various reported safety indicators publicly available. An indicator being available in 'all' jurisdictions indicates data is publicly available in RIN responses published on our website.[108] The listed data sources below highlight what is published systematically at the time of drafting and does not include all jurisdictional safety data collected or reported for compliance

105 TasNetworks (distribution and transmission), *Publications: Annual reports*, accessed 29 March 2022.

106 Power and Water, *Corporate reports: annual reports*, accessed 29 March 2022.

107 Department of the Attorney-General and Justice – Electricity Safety Regulator, *Annual report 2020–2021*, 2021.

108 AER, *Performance Reporting (Electricity RIN responses)*, accessed 9 June 2022.

purposes. For example, regulators responsible for workplace health and safety do not necessarily publish the indicators they collect. It is also worth highlighting that the ESV in Victoria tracks an extensive range of performance indicators, but often publishes information with respect to specific investigations or enforcement actions rather than routinely. For instance, in addition to what Table 7-2 identifies, the ESV routinely tracks various reportable incidents; including shocks and electrocutions, electrical incidents that started a fire and community contact with powerlines. The ESV also routinely tracks asset inspections, asset failures, vegetation management and bushfire preparedness, near misses, interruptions caused by vegetation, unauthorised access and more.

Table 7-2: Various reported safety indicators currently publicly available

Leading safety indicators		Jurisdiction
Proactive maintenance	Poles and towers owned, due for inspection, inspected, condemned	ACT (T)
	Poles owned, tested, condemned (plus % remediated)	ACT (D)
	Tasks complete: routine, corrective, line, substation	SA (T)
	Asset inspections, including by asset type	QLD, NSW, all
	Assets replaced/repaired by type (poles, overhead conductors, wires)	QLD, all
	Asbestos removal (sqm materials, tonnes soil/ customer premises)	QLD
	Powerline clearance issues addressed	QLD
	Inspection and corrective action tasks outstanding	NSW
Near misses	Significant near misses	SA (D)
	Near misses involving NSP personnel	ACT
	Safe approach distance violations (broken into categories)	NSW
	Intentional unauthorised access (broken into categories)	NSW
	Control failure near misses by asset category functional failures and by contained fire, escaped fire and no fire	NSW
Vegetation management	Vegetation encroachments	ACT (T)
	Spans of vegetation managed	All
	Rate of major non-compliance by hazardous and low bushfire risk areas	VIC
	Vegetation inspections (aerial, ground, bushfire prone land, outstanding)	NSW
Safety processes	Workplace inspections carried out	SA (D)
	Designs where safety in design reports completed and audited, project safety reviews performed	NSW
Emergency preparedness	Completed emergency management plan exercises	SA
	Completion of bushfire preparedness tasks	NSW
Potentially leading or lagging safety indicators		

Leading safety indicators		Jurisdiction
Asset failures	Primary and secondary major asset failures	ACT (T)
	Overhead service conductor and pole failures	ACT (D)
	Plant requiring replacement	SA (T)
	Asset failure by asset category and against 10-year averages (VIC)	All, VIC
	Defective neutrals	ACT (D)
Lagging safety indicators		**Jurisdiction**
Shocks and switching incidents/arc flashes	Shock reports per 1,000km mains	SA (D)
	Shocks	SA (T)
	Dangerous reported electric shock incidents	ACT (D)
	Switching incidents per number of switching plans issued	SA (T)
	Switching incidents	SA (D)
	Arc flashes combined with shocks (disaggregated by worker, public, etc)	NSW
Fire incidents	Dangerous fire incidents	ACT (D)
	Fire starts caused by grow-ins or fall/blow-ins (NSP responsibility)	All
	Fire starts per 1,000km mains	SA (D)
	Network incidents resulting in ground fires by type of asset failure or contact	VIC
Incidents	Significant incidents or major incidents (by workers, public, etc)[109]	TAS, NSW
	Incidents disaggregated by workers, public, etc	NSW
	Significant incident frequency rate	QLD
	Reportable incidents (by safety and environmental) [110], notifiable incidents	TAS, ACT (D)
	Deaths/fatalities	ACT (D), VIC
	Community powerline safety incidents involving network contact	QLD
	Critical infrastructure incidents and consequential safety impacts	NSW
	Serious injuries, including details	VIC
Workplace injuries	Lost time injuries	SA (D)
	Lost time injury frequency rates	QLD, NT
	Total recordable injury frequency rates[111]	TAS, QLD
	Injuries by >1 day lost, medical treatment, per million hours worked	SA (T)

109 Significant incidents in Tasmania are incidents with an actual or credible potential for major or severe health, safety, or environment consequences as defined by TasNetworks' (distribution and transmission) risk matrix. Major incidents in NSW are defined in IPART, *Electricity networks reporting manual - incident reporting*, 2022 as being regarded as 'High Level Severity' for the purpose of DNSP licence conditions.

110 Reportable incidents in Tasmania are incidents that require notification to a government authority.

111 Measured as recordable injuries divided by total hours worked by staff over a 12-month period, multiplied by one million.

Leading safety indicators		Jurisdiction
Damage to property or environment	Serious property damage	ACT (D)
	Damage claims per 1,000 km of mains	SA (D)
	Serious environmental damage	ACT (D)
	Interruptions caused by vegetation grow-ins or fall/blow-ins	NSW
	Network-initiated property damage (third party versus network property)	NSW
Network contact	Broken down by overhead asset, underground asset, what made contact	NSW
	Broken down by what made contact (animal, tree, vehicle, lightening, digging, other) and against 10-year averages	VIC

When analysing the available data and consulting with jurisdictional regulators, we identified the following network safety tends or issues:

- Some jurisdictional regulators observed trends around increasing incidents due to farm machinery contact with the network. This appears driven by the trend towards larger farming equipment.
- Some insights are provided in jurisdictional regulator reports. For instance:
  - Evoenergy has some reporting, safety management and asset management concerns, although has demonstrated a commitment to improve its safety management systems. Evoenergy also recently reported notable increases in notifiable incidents and defective neutrals, with the former potentially due to improved reporting after a public safety awareness campaign.[112]
  - ESV's reporting of incidents, investigations and enforcement actions highlights concerns around maintenance and replacement volumes (for example, insufficient pole maintenance and powerline clearance by Powercor).[113]
  - No obvious safety issues or emerging trends were identified in NSW when comparing completed versus panned maintenance tasks and failure rates against five-year averages.[114]
  - Energy Queensland has reported high levels of expenditure (particularly in Ergon Energy's network) driven by safety. This could indicate a relatively strong safety focus for Ergon Energy at this current point in time, noting we would not typically expect proactive maintenance activities to be lumpy. We also note that in most cases, expenditure with safety benefits will not be safety-specific (with some exceptions, such as asbestos removal).

[112] ACT Government, *Utilities technical regulation annual compliance report 2019-20*, 2021, pp. 7,14.

[113] Energy Safe Victoria, *Safety performance report on Victorian electricity networks*, 2021, pp. 8–9.

[114] IPART, *Annual compliance report - Energy network operator compliance during 2020-21*, 2021, p. 27.

8 Looking ahead

Each year, we identify issues that could be investigated as focus areas in future electricity network performance reports. Our work this year has identified several potential focus areas for 2023:

- Examining future price drivers, especially asset age, replacement costs, utilisation and interest rates.
- Investigating what DNSPs are doing and what tools they have available to identify customer vulnerability (for example, identifying underconsumption due to energy poverty). Our ability to provide meaningful analysis on this topic will likely depend on what network data is available for us to collect.
- Reporting on measures of consumer outcomes, including customer service measures. ENA suggested reporting on outputs as well as inputs would more effectively demonstrate the value for money that network customers receive. While current reliability measures and export service performance (discussed below) entail reporting on outputs, customers may value other service outputs. For example, AusNet Services' customers identified that they value communication around outages and customer service for connections and complaints, which lead these outputs for AusNet Services' to be incentivised under the customer service incentive scheme.[115]

In addition, by 31 December 2023, we will expand our reporting to cover DNSPs' performance in providing export services for embedded generators (such as residential solar).[116] When introducing this reporting role, the AEMC noted that this reporting could provide 'reputational incentives' with respect to the efficient provision of export services.[117] This reporting will include matters we consider appropriate, which the NER suggest may include information about:

- the relative performance of each DNSP in providing the distribution services
- the use of static zero export limits
- the impact of system limitations on availability or use of the distribution services
- performance relative to export tariff offerings.

We are considering how to best incorporate this new function into our next report, including implications on the timing. One option is to publish our 2023 electricity network performance report to a similar schedule as this year and release an update at the end of the year to incorporate the new reporting function.

In 2021, we identified potential focus areas that were ultimately not included in this report. These included analysis of planned outage trends and the drivers of recent network investment. Subject to resourcing, priorities and stakeholder interest, these topics could be carried forward as focus areas in 2023.

115 AER, *Explanatory statement: Customer service incentive scheme, June 2020,* accessed 11 May 2022.

116 As required under Rule 6.27A of the NER: *Annual DER network service provider performance report*, accessed 5 April 2022.

117 AEMC, *Rule determination: National Electricity and Energy Retail amendment (access, pricing and incentive arranges for distributed energy resources) Rule 2021*, 12 August 2021, p. 48, Accessed 4 May 2022.

Moreover, we asked stakeholders this year whether they considered the benefits of reporting statutory measures would exceed the costs. We did not receive any clear support for this reporting and ENA was unclear on how statutory reporting measures would add to existing profitability measures. We share ENA’s view. We also recognise that substantial methodological and implementation issues with statutory measures limit their practical use for understanding NSPs’ performance under the regulatory regime.

Appendix A: New tariffs in tariff structure statements

This appendix summarises the types of tariffs that DNSPs have provided in tariff structure statements for residential customers (Table A-1) and small and medium business customers (Table A-2).

Table A-1 New residential tariffs

DNSP	Tariff	Customer type	Assignment	Meter type	Tariff structure*
Evoenergy	Residential demand	New customers with smart meters	Opt-out	Type 4/4A	Consumption usage (c/kWh) Demand charge (c/kWh/day) Bill based on highest demand 30min interval each month Peak window 5-8pm every day
Ausgrid	Residential time of use	New and existing	Opt-out		Peak / Shoulder / Off-peak periods
	Residential transitional tariff	Existing customers New	Reassignment Opt-in	Interval - minimum requirement	Same rate applies to peak, shoulder, and off-peak charging windows
Endeavour Energy	Residential time of use	Existing customers New	Opt-in (Existing) Opt-out (New)	Interval -minimum requirement	Peak / Shoulder / Off-peak periods
Essential Energy	Residential opt-in time of use	New and existing	Opt-in	Interval meter	Peak / Shoulder / Off-peak periods
	Residential interval time of use	New	Opt-in for new customers with meter upgrade or solar PV	Interval meter	Peak / Shoulder / Off-peak periods
Energex Energy	Residential demand tariff	New and existing	Opt-in and opt-out	Advanced interval meter	Consumption charge Peak demand charge based on 30min interval with highest demand during 4-8pm window
Ergon Energy	Demand seasonal time of use	New and existing	Opt-in	Advanced/interval meter	Peak: 3:00pm to 9:30 pm all summer days Off-peak periods: 3:00pm to 9:30pm all non-summer days

DNSP	Tariff	Customer type	Assignment	Meter type	Tariff structure*
					Energy: anytime energy (volume) charge applied to all metered consumption Summer: December to February
	Energy seasonal time of use	New and existing	Opt-in	Advanced/interval meter	Peak: 3:00pm to 9:30 pm all summer days Off-peak: All other times Summer: December to February
SA Power Networks	Residential demand tariff	New and existing	Retailer request	Interval meter	Consumption charge with peak and off-peak component and solar sponge option Demand charge with seasonal peak based on 30-minute interval with highest demand that month
TasNetworks (D)	Residential time of use demand	New and existing	Opt-in	Type 6 - minimum requirement	Peak demand (7-10am, 4-9pm weekdays) Off-peak demand (other times)
AusNet (D), CitiPower, Jemena Electricity, Powercor Australia, United Energy	Residential consumers <160 MWh pa	New and existing	Opt-in[118]		Consumption (energy) charge Demand charge with seasonal variation. Monthly demand based on highest 30min interval during window (3-9pm weekdays).

Source: AER analysis and tariff structure statements.

* Note: All tariff structures also have a fixed charge component.

118 Victorian Government Gazette, Order in Council, Advanced Metering Infrastructure (AMI Tariffs) Amendment Order 2016, 2016.

Table A-2 New small and medium business tariffs

DNSP	Tariff	Customer type	Assignment	Meter type	Tariff structure*
Evoenergy	Small business demand	New customers with smart meters	Opt-out	Type 4/4A	Consumption usage (c/kWh) Demand charge (c/kWh/day) Bill based on highest demand 30min interval that month. Peak charging window 7am-5pm every day.
Ausgrid	Small business time of use	New Existing	Default opt-out Default reassignment opt-out	Interval meter	Peak / Shoulder / Off-peak periods
	Small business transitional	New Existing with interval or meter upgrade	Opt-in from ToU Reassignment from non-ToU	Interval meter	Same rate applies to peak, shoulder, and off-peak charging windows
Endeavour Energy	Small business time of use	New Existing with interval or meter upgrade	Default Opt-out Opt-in reassignment from non-ToU	Interval meter	Peak / Shoulder / Off-peak periods
Essential Energy	Small business opt-in time of use	Existing non-time of use	Opt-in	Interval meter	Peak / Shoulder / Off-peak periods
	Small business interval time of use	New/Existing	Meter upgrades and solar PV customers		Peak / Shoulder / Off-peak periods
SA Power Networks	Small business demand tariff	New and existing	Retailer request	Interval meter	Consumption charge with single block Peak demand charge 100% of LRMC with different seasonal peak prices based on highest demand 30min interval that month Shoulder charge
	Small business demand transitional tariff	New and existing upgrades to multiphase supply with a new meter	Default assignment and ability to opt-in	Interval meter	Consumption charge with single block Peak demand charge 50% of LRMC with different seasonal peak prices based on highest demand 30min interval that month

DNSP	Tariff	Customer type	Assignment	Meter type	Tariff structure*
					Shoulder charge
TasNetworks (D)	Residential time of use demand	New and existing	Opt-in	Type 6 - minimum requirement	Peak demand (7-10am, 4-9pm weekdays) Off-peak demand (other times)
AusNet (D), CitiPower, Jemena Electricity, Powercor Australia, United Energy	Small business consumer Medium business	New and existing	Opt-in[119]	Advanced interval meter	Consumption (energy) charge Demand charge with seasonal variation. Monthly demand based on highest demand 30min interval in window (10am-6pm weekdays). Demand charging window 3-9pm weekdays (AusNet (D) only)

Source: AER analysis and tariff structure statements.

* All tariff structures also have a fixed charge component.

119 Victorian Government Gazette, Order in Council, *Advanced Metering Infrastructure (AMI Tariffs) Amendment Order 2016*, 2016.

Appendix B: Objectives of network performance reporting

Through this report and the accompanying data, we intend to advance the network performance reporting objectives, determined with the input of stakeholders. These are set out in Table B-1.

Table B-1 How we are advancing our objectives for network performance reporting

Objective	What we are doing
Provide an accessible information resource	We have drafted this report to be informative and accessible for stakeholders. Alongside this report, we have published two data models covering: • Our operational performance data. • Our financial performance data. These models include much of the data captured in this report at a greater level of detail. We aim to present the data in a form that enables stakeholders to use it in their own analysis. We have also undertaken a survey of publicly available reporting on electricity network safety and have summarised our findings as a resource for stakeholders.
Improve transparency	Through the report and our published data, we are trying to illustrate the impacts and interactions of network performance under different regulatory tools or settings. The regulatory regime can be complex. Our objective through this reporting is to make network regulation and its outcomes more transparent for stakeholders. For example, in this report we have reported on the progress of network tariff reform.
Improve accountability	The focus of this report is on the effectiveness of network regulation as a whole, increasing our accountability for regulatory decisions and for the NSPs and their performance under those decisions. Further, our published data allows for comparisons of individual NSPs. Our published data and analysis highlights areas where particular NSPs depart from broader trends.
Encourage improved performance	By improving accountability and transparency, these reports should contribute to improved performance over time by: • Informing ourselves and stakeholders about emerging trends that may require a regulatory response. • Contributing to the incentives on NSPs to improve performance.
Inform consideration of the effectiveness of the regulatory regime	Our analysis in this report is intended to support consideration of how the regulatory regime contributes to network performance and outcomes. We aim to explore where actual outcomes depart from forecasts or trends, whether this is widespread and what implications that has for our regulatory approaches.
Improve network data resources	Through our analysis of the data, we have sought to: • Investigate and make use of a wide range of our network data sources. • Identify and manage differences in reporting which impede comparability of data provided by different NSPs. • Identify important questions on which we would like to form views but are limited by data availability or consistency. Over time, we expect this approach will also assist us to form a view on any data we currently collect which may be excessive or not useful.

Source: AER analysis; AER, Objectives and priorities for reporting on regulated electricity and gas network performance—Final, June 2020.

We welcome stakeholder feedback on the report and accompanying data resources so we can improve its usefulness over time. Stakeholders willing to provide input are encouraged to email networkperformancereporting@aer.gov.au.

Appendix C: Figures source data

The source data for figures included in this report are found in:

- our operational and financial performance datasets
- Annual RINs (AR), Economic Benchmarking RINs (EB) and Category Analysis RINs (CA)
- the regulatory determination Roll Forward Models (RFMs) and Post Tax Revenue Models (PTRMs).

Table C-1 provides the specific data source for each figure and any calculations made to the data.

Table C-1 Data source for Figures included in Electricity Network Performance Report

Figure	Data	Data Source	Calculation
Figure 2-1	Regulatory determination periods	No AER data used	N/A
Figure 3-1	Network Revenue - DNSPs and TNSPs	DNSP Revenue - AR - 8.1.1.1 Revenue - Standard control services. Where not available EB -3.1.1 Revenue grouping by chargeable quantity - Standard Control Services. TNSP Revenue - EB -3.1.1 Revenue grouping by chargeable quantity	DNSP and TNSP network revenue converted into $ Jun 2021 terms
Figure 3-2	Building block model to forecast network revenue	No AER data used	N/A
Figure 3-3	Building block revenue components	Forecast revenue - PTRM - Revenue summary - Building block components	Forecast revenue converted into $ Jun 2021 terms
Figure 3-4	Incentive scheme payments	Incentive Scheme Payments - EB - 3.1.3 Revenue (penalties) allowed (deducted) through incentive schemes.	Incentive scheme payments converted into $ Jun 2021 terms
Figure 3-5	Capex and opex compared to forecast capex and opex	DNSP capex - RFM - RFM input - actual capex, actual asset disposal, actual capital contributions. Where not available AR - 8.2.4 Capex by asset class, 8.2.5 Capital contributions by asset class, 8.2.6 Disposals by asset class TNSP capex - RFM - RFM input - actual capex, actual asset disposal, actual capital contributions. Where not available CA - 2.1 Expenditure Summary	Capex and opex converted into $ Jun 2021 terms Net capex is gross capex, less capital contributions and less disposals.

Figure	Data	Data Source	Calculation
		DNSP and TNSP Operating Expenditure - EB - Table 3.2.2 Opex consistency Forecast capex - PTRM - PTRM Input - Forecast net capex Forecast opex - PTRM - PTRM Input - Forecast operating and maintenance expenditure	
Figure 3-6	DNSP and TNSP RAB values	DNSP and TNSP RAB values - RFM - RAB roll forward	RAB values converted into $ Jun 2021 terms
Figure 3-7	DNSP and TNSP RAB per customer	DNSP and TNSP RAB values - RFM - RAB roll forward Customer Numbers - EB - 3.4.2 - Distribution customer numbers by customer type or class	RAB values converted into $ Jun 2021 terms RAB values divided by number of customers
Figure 3-9	Unplanned outages - DNSP	Whole of network unplanned SAIDI - EB - 3.6.1 Reliability Whole of network unplanned SAIDI excluding excluded outages- EB - 3.6.1 Reliability Whole of network unplanned SAIFI - EB - 3.6.1 Reliability Whole of network unplanned SAIFI excluding excluded outages- EB - 3.6.1 Reliability	Normalised outage duration and frequency normalised proportionally across DNSPs by using customer numbers. Normalised excluded outage duration and frequency normalised proportionally across DNSPs by using customer numbers.
Figure 3-9	Customer average interruption	Whole of network unplanned SAIDI - EB - 3.6.1 Reliability Whole of network unplanned SAIFI - EB - 3.6.1 Reliability Customer Numbers - EB - 3.4.2 - Distribution customer numbers by customer type or class	Outage duration and frequency normalised proportionally across DNSPs by using customer numbers. Normalised outage duration divided by normalised outage frequency
Figure 3-10	Reliability by feeder	Unplanned minutes off supply - AR - 6.2.1 Unplanned minutes off supply (SAIDI).	Unplanned minutes off supply normalised proportionally across DNSPs by using customer numbers for each DNSP's feeder.
Figure 3-11	Network utilisation	Non-coincident summated raw system annual maximum demand - EB - 3.4.3.3 Annual system maximum demand characteristics at the zone substation level - MVA measure	System capacity utilisation rate calculated by dividing total non - coincident summated raw system annual maximum demand by total zone substation transformer capacity

Figure	Data	Data Source	Calculation
		Zone substation transformer capacity - EB - 3.5.2.2 - Zone substation transformer capacity	
Figure 3-12	Maximum demand per customer	Non-coincident summated raw system annual maximum demand - EB - 3.4.3.3 Annual system maximum demand characteristics at the zone substation level - MVA measure Customer Numbers - EB - 3.4.2 - Distribution customer numbers by customer type or class	Total non-coincident summated raw system annual maximum demand divided by customer numbers
Figure 4-1	DNSP and TNSP real return on assets	Return on Assets - Financial Performance data	Return on assets specified in financial performance data. Additional detail provided in return on assets explanatory note.
Figure 4-2	Real return on assets and forecast real rate of return	Return on Assets - Financial Performance data Real WACC - PTRM - WACC	Return on assets specified in financial performance data. Additional detail provided in return on assets explanatory note.
Figure 4-3	DNSP and TNSP real EBIT per customer	EBIT per customer - Real - Financial Performance data	Return on assets specified in financial performance data. Additional detail provided in EBIT per customer explanatory note.
Figure 4-4	Transaction and trading multiples of regulated NSPs	No AER data used. Data sourced from Morgan Stanley Research	N/A
Figure 4-5	DNSP and TNSP real return on regulated equity	Return on regulated equity - Financial Performance data Post-tax Real Return on Equity - PTRM – WACC	Return on assets specified in financial performance data. Additional detail provided in return on assets explanatory note.
Figure 4-6	Incremental contributions to return on regulated equity	Return on regulated equity - Financial Performance data Post-tax Real Return on Equity - PTRM - WACC	Return on assets specified in financial performance data. Differences between actual returns and forecast returns. This calculation involves substituting for each factor, one at a time, our forecast of that factor for a network in place of the actuals that the NSPs have reported. Factors that contribute to differences between actual and forecast returns are also

Figure	Data	Data Source	Calculation
			explained in return on assets explanatory note.
Figure 5-1	Residential customers with smart meter installed	Residential smart meter installations - AR - P1.1 Distribution customer numbers by meter type -	N/A
Figure 5-2	Non-residential customers with smart meter installed	Non-residential smart meter installations - AR - P1.1 Distribution customer numbers by meter type	N/A
Figure 5-3	Residential customers with smart meter installed compared to cost reflective tariffs	Residential smart meter installations - AR - P1.1 Distribution customer numbers by meter type Cost reflective tariffs - AR - P1.3A NMI Count by tariff type	N/A
Figure 5-4	Non-residential customers with smart meter installed compared to cost reflective tariffs	Non-residential smart meter installations - AR - P1.1 Distribution customer numbers by meter type Cost reflective tariffs - AR - P1.3B NMI Count by tariff type	N/A
Figure 5-5	Type 4 and Type 4A meters installed	AER retail performance data - reasons for a type 4 or 4A meter installation	N/A
Figure 5-6	Network revenue by chargeable quantity	Revenue by chargeable quantity - EB - 3.1.1 Revenue grouping by chargeable quantity - Standard Control Services.	N/A
Figure 5-7	Energy delivered by chargeable quantity	Energy delivered by chargeable quantity - EB - 3.4.1.1 - Energy grouping - delivery by chargeable quantity	N/A
Figure 5-8	Smart appliances to reduce cost of household energy bills	No AER data used. Data sourced from Energy Consumers Australia - National behavioural survey results	N/A
Figure 5-9	Smart meters devices installed	No AER data used. Data sourced from Energy Consumers Australia - National behavioural survey results	N/A
Figure 6-1	Reliability measures in the AER's Reliability Measures Guideline	No AER data used	N/A
Figure 6-2	DNSP MED Threshold	Duration of sustained customer Interruption - CA - Table 6.3.1 - Sustained interruptions to supply	MED threshold calculated as 2.5 standard deviations greater than the mean of the log normal distribution of five regulatory years' SAIDI data

Figure	Data	Data Source	Calculation
Figure 6-3	Minutes of outages and major event days	Duration of sustained customer Interruption - CA - Table 6.3.1 - Sustained interruptions to supply MED - CA - Table 6.3.1 - Sustained interruptions to supply	Minutes of outages calculated by multiplying the number of customers affected by the interruption by the average duration of sustained customer interruption
Figure 6-4	Minutes of outages as percentage of month's electricity supply	Duration of sustained customer Interruption - CA - Table 6.3.1 - Sustained interruptions to supply	Minutes of outages calculated by multiplying the number of customers affected by the interruption by the average duration of sustained customer interruption Minutes of outages divided by total minutes in respective month
Figure 6-5	Minutes of outages excluding major event days	Duration of sustained customer Interruption - CA - Table 6.3.1 - Sustained interruptions to supply MED - CA - Table 6.3.1 - Sustained interruptions to supply	Minutes of outages calculated by multiplying the number of customers affected by the interruption by the average duration of sustained customer interruption
Figure 6-6	Definition of a natural disaster cost pass through	No AER data used	N/A
Figure 6-7	Natural disaster cost pass through applications approved	Individual NSP cost pass through applications for natural disaster cost pass throughs	Cost pass through expenditures converted into $ Jun 2021 terms
Figure 6-8	Natural disaster cost pass through applications approved	Individual NSP cost pass through applications for natural disaster cost pass throughs	Cost pass through expenditures converted into $ Jun 2021 terms