Annual Benchmarking Report

Electricity distribution network service providers

November 2024

AUSTRALIAN ENERGY REGULATOR

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Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Email: aerinquiry@aer.gov.au
Tel: 1300 585 165

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Executive summary

We report annually on the productivity growth and efficiency of the distribution network service providers (DNSPs) individually, and the distribution industry as a whole, in the National Electricity Market (NEM). This meets the requirement under the National Electricity Rules (NER) that we prepare annual benchmarking reports.[1] These DNSPs operate transformers, poles and wires to deliver electricity from the transmission network to residential and business customers, as well as providing export services for distributed generation. Distribution and transmission network costs typically account for 35–45% of what consumers pay for their electricity in most jurisdictions (with the remainder covering generation costs, retailing costs, and environmental policies).

We undertake economic benchmarking to measure how productively efficient these networks are at delivering electricity distribution services over time and compared with their peers. This has several uses and benefits as the benchmarking results:

- inform our assessment of proposed network expenditures, and whether they are efficient, when setting the maximum revenues DNSPs can recover from customers
- provide distribution network owners with information about the productivity of their business, which along with the incentives under the framework, provides financial and reputational incentive to improve their efficiency
- provide consumers with accessible information about the relative efficiency of the networks they rely on
- provide policy makers with information about the impacts of regulation on network costs and productivity.

Below we set out our key findings in this year's report. This includes a focus on productivity trends over time and changes in the most recent year of 2023. Examining trends helps to account for volatility, allow for any delayed effects of inputs on outputs and draw out any cycles.

Distribution network industry productivity improved after 2015 but has declined since 2021

Electricity distribution industry productivity, as measured by total factor productivity (TFP), decreased over the 2006–15 period at an average annual rate of 1.4%. Following this, it trended up over the period 2015–23 at an annual average rate of 0.9% per year. This more recent improvement reflected a decline in inputs, primarily lower operating expenditure (opex) input, and consequently improved opex partial factor productivity (PFP) as seen in Figure 1. The long-term decline in capital PFP also seen in Figure 1 is comparable to that of most other industries in the Australian market economy and is reflective of an increase in the amount of capital per worker.[2]

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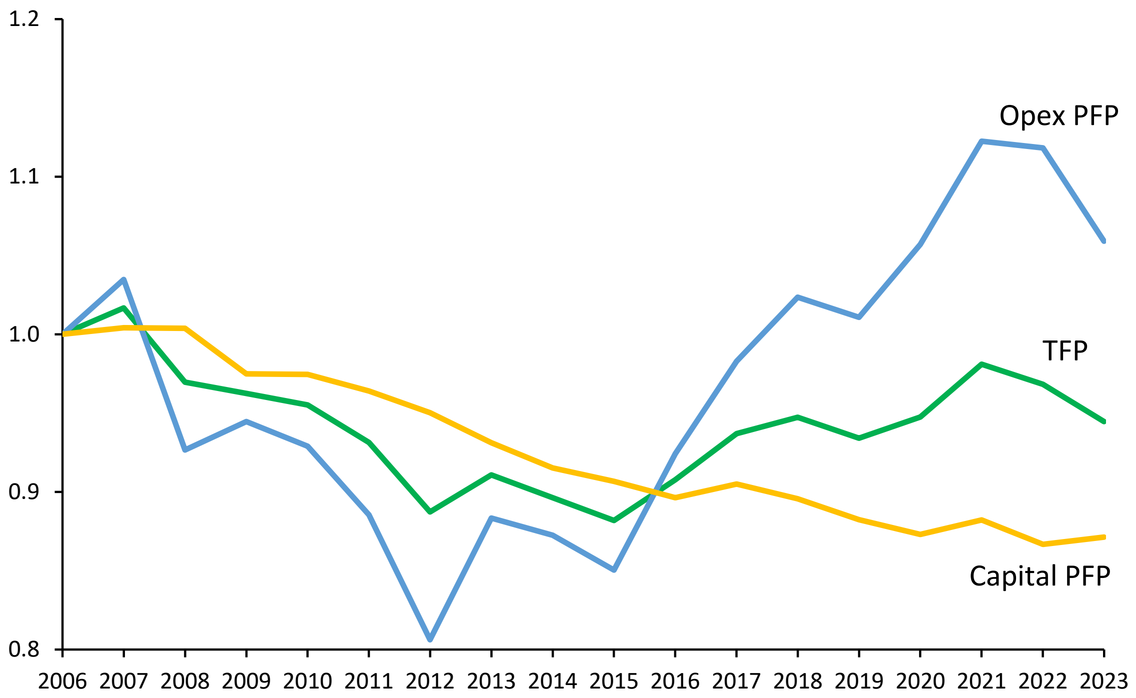
1 NER, cll 6.27(a) and 6.27(c).

2 Australian Bureau of Statistics, *Tables 1-19: Estimates of Industry Multifactor Productivity*, December 2023.

Despite this more recent upward trend in electricity distribution productivity, TFP for the industry decreased by 2.5% in 2023. This was the largest year-on-year decrease since 2012 and was primarily driven by higher opex. There was no one common driver of higher opex across the distribution industry. Intensified vegetation management arising from bushfire risk related regulatory obligations, higher emergency response costs due to storm and flood events, and the clearing of maintenance backlogs after the COVID 19 pandemic were amongst the many drivers listed by DNSPs. TFP also decreased by 1.3% in 2022, largely due to a fall in reliability. Despite these falls, productivity remains around the level it was in 2020. Given there was no common driver behind the decreasing productivity observed in 2022 and 2023, the results in next year's report will provide further information about whether distribution TFP has entered a new downward trend or could be maintained.

Figure 1 Electricity distribution total, capital and opex productivity, 2006–23



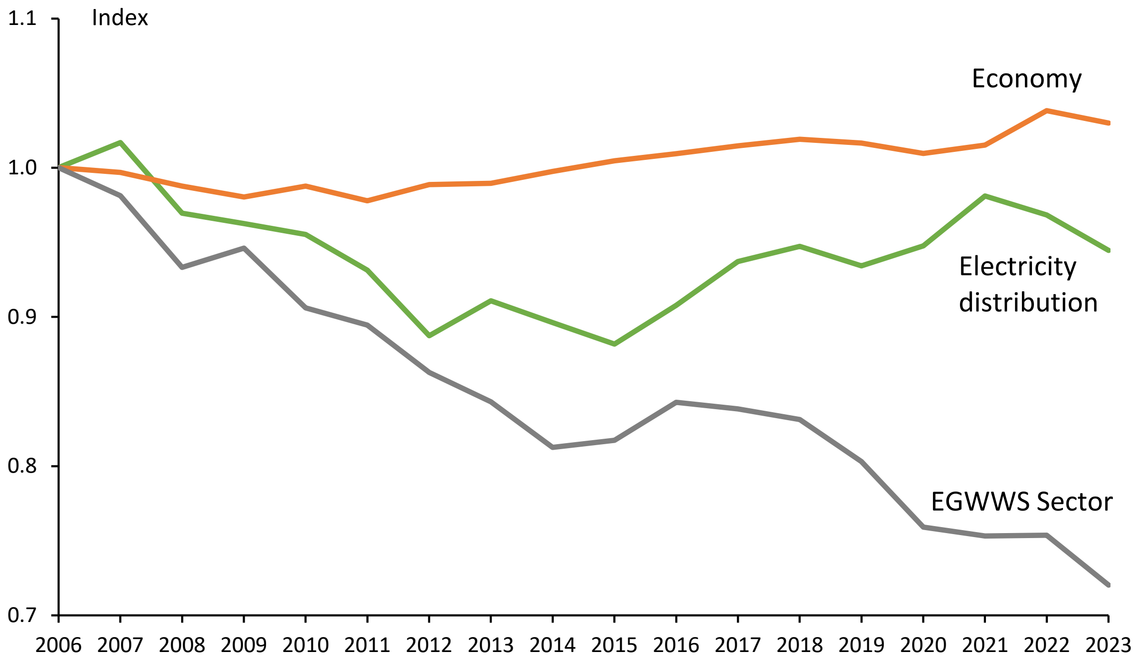
Source: Quantonomics; AER Analysis

In Figure 2, we see that over the 2006–23 period, the electricity distribution industry performed better than the utilities sector (specifically, the electricity, gas, water and waste services – EGWWS sector), and performed worse compared to the overall Australian economy. The continued long-term decline in utility sector productivity is likely to be a result of structural changes driving higher input costs whilst not necessarily being reflected as higher outputs. [3] These structural changes can include regulatory requirements designed to improve reliability and safety and reduce negative environmental impacts. In 2023, the utilities sector saw a productivity decline of 4.6% while the overall Australian economy saw a 0.8% decline (compared to a decline of 2.3% for electricity distribution). The divergence in

[3] Productivity Commission, *Productivity Update*, May 2013, pp. 33–34.

productivity observed between the electricity distribution industry and the utilities sector was reinforced in 2023 as a result of the utility sector's productivity decline being much greater relative to the electricity distribution industry.

Figure 2 Electricity distribution, EGWWS sector and economy productivity, 2006–23



Source: Quantonomics; AER analysis.

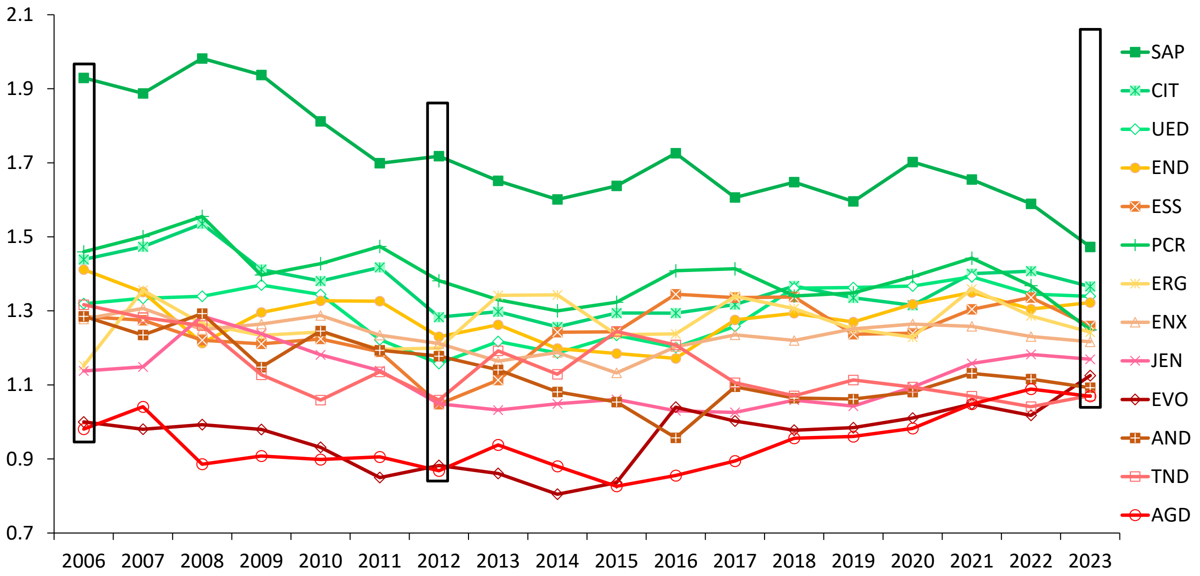
DNSP productivity has converged over time, primarily driven by opex

The relative productivity of DNSPs as measured by panel data multilateral total factor productivity (MTFP) can be seen in Figure 3. Since 2006 there has been some convergence in the productivity levels of DNSPs as measured by MTFP. This can be seen through a shrinking gap between the most and least productive DNSP over time (the three equal-sized, black bordered columns placed in 2006, 2012 and 2023 in Figure 3). This reflects a number of factors, including:

- those DNSPs which have been the least productive over time have improved their performance since 2012
- some middle ranked DNSPs have also gradually improved their relative MTFP performance to be closer to the top ranked DNSP
- the most productive DNSPs have experienced a gradual overall decline in productivity since 2006, including over the 2012–23 period.

Convergence in opex multilateral partial factor productivity (MPFP) was the primary driver of the material changes in MTFP, with capital MPFP declining continually for most networks over this period and relatively few changes in the rankings of individual DNSPs.

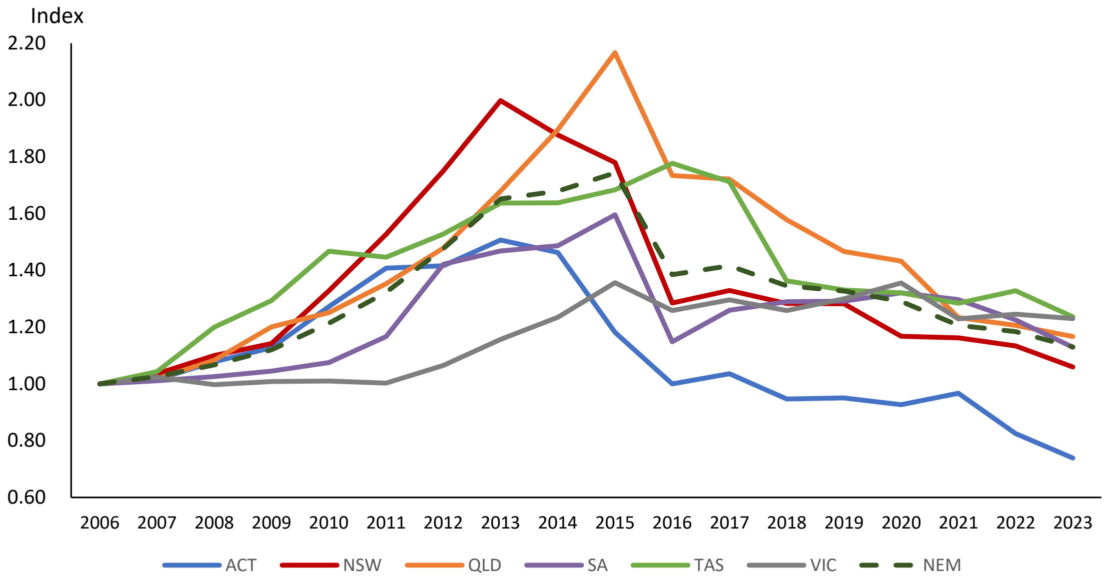
Figure 3 MTFP indexes by individual DNSP, 2006–23



Source: Quantonomics; AER analysis.

The relative productivity improvements of the lower and middle ranked DNSPs have been one contributor[4] to the reductions in distribution network costs and revenues. Figure 4 shows that distribution network revenues (and consequently network charges paid by consumers) have fallen in all jurisdictions in the NEM from around 2015.

Figure 4 Indexes of distribution network revenues by jurisdiction, 2006–23



Source: Economic Benchmarking RIN; AER Analysis

4 Other contributors to declining revenue include but are not limited to declining cost of capital and lower capex resulting from lower demand growth forecasts.

Continuing to improve our economic benchmarking

We operate an ongoing transparent program to review and incrementally refine and develop elements of the benchmarking methodology and data. This includes where necessary considering if, and how, the changing environment DNSPs operate in (the broader economy and within the context of the energy transition) impacts the benchmarking methodology and data.

As a part of this, we consult with stakeholders and value the feedback they provide in both reviewing the annual report and providing views around specific development issues. There can be diversity in the feedback provided. This contributes to our thinking and ongoing improvement in the benchmarking, even in instances where we do not necessarily agree with points raised or adopt the specific suggestions.

We prioritise the benchmarking development work, balancing a variety of factors and associated costs and benefits, including stakeholder feedback. In addition, we consider the materiality and impact of the development work and the potential for errors, particularly in relation to upcoming revenue determinations where the benchmarking is used, and the ability to progress this work from sequencing, data availability and resourcing perspectives. This work is often complex and resource-intensive, therefore we exercise judgement in identifying the relative priorities and progressing the program of work.

In this year's report, we prioritised and progressed the following benchmarking refinements and development work:

- We have refined the way we calculate the annual user cost (AUC) of capital, which we use to determine the weights applying to our capital inputs. This was because of unintended impacts of the changing inflation environment, which drove changes in the results not related to movements in efficiency.
- We finalised our approach to addressing differences in capitalisation between DNSPs. This followed initial implementation in last year's report, after finalisation of our associated guidance note responding to industry wide feedback. As a result of implementing this approach, direct comparison of the results in this report against those in previous Annual Benchmarking Reports is not possible.
- We completed an independent review of the non-reliability output weights we use in our TFP and MTFP benchmarking. This responded to stakeholder feedback after a computation error was corrected for in in our 2020 Annual Benchmarking Reports. The review found that there were no further errors in the way these weights are now computed, generally endorsed our approach, and suggested some minor modifications to our method to improve its numerical stability.

Over the next year the key development priority is to continue to improve, where possible, the performance and reliability of the econometric opex cost function models. This reflects stakeholder feedback around the importance of this work and that we use these results in revenue determinations to inform the efficiency of a DNSP's opex and any efficiency adjustments. We are initiating consultation on this issue as a part of the release of this report.

Beyond this, at this stage we plan to review from 2025–26, the benchmark comparison point used in the application of the econometric opex cost function models. We will also re-examine in 2027 what, if any, changes to the TFP and MTFP benchmarking models are required to further account for DNSPs' expanding provision of export services.

Contents

1 Our benchmarking report

The NER require the AER to publish benchmarking results in an annual benchmarking report.[5] This is our 11th benchmarking report for DNSPs. This report is informed by expert advice provided by Quantonomics.[6]

National Electricity reporting requirement

6.27 Annual Benchmarking Report

(a) The AER must prepare and publish a network service provider performance report (an annual benchmarking report) the purpose of which is to describe, in reasonably plain language, the relative efficiency of each Distribution Network Service Provider in providing direct control services over a 12-month period.

Productivity benchmarking is a quantitative or data-driven approach used widely by governments and businesses around the world to measure how efficient firms are at using input to produce outputs over time and compared with their peers.

Our benchmarking report considers productive efficiency. DNSPs are considered productively efficient when they produce their goods and services at least possible cost given their operating environments and prevailing input prices. We examine trends in productivity over the full period of our benchmarking analysis (2006–23), shorter time periods and between 2022 and 2023.[7]

1.1 Benchmarking techniques

Our benchmarking report presents results from three types of 'top-down' benchmarking techniques.[8] Each technique uses a different method for relating outputs to inputs to measure and compare DNSP efficiency:

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5 NER, cll 6.27(a) and 6.27(c).

6 The supplementary Quantonomics report outlines the full set of results for this year's report, the data we use and our benchmarking techniques. It can be found on the AER's benchmarking website.

7 Throughout this report, we refer to regulatory years. For non-Victorian DNSPs, this is financial years (for example, 2023 refers to the 2022–23 financial year). For Victorian DNSPs, this is calendar years up to and including 2020, and financial years from 2021 (for example, 2020 refers to the 2020 calendar year, but 2021 refers to the 2020–21 financial year).

8 Top-down techniques measure a network's efficiency based on high-level data aggregated to reflect a small number of key outputs and key inputs. They generally take into account any synergies and trade-offs that may exist between input components. Alternative, bottom-up benchmarking techniques are much more resource intensive and typically examine very detailed data on a large number of input components. Bottom-up techniques generally do not take into account potential efficiency trade-offs between input components of a DNSP's operations.

- **Productivity index numbers (PIN).** These techniques use a mathematical index to measure the relationship between multiple outputs and inputs, enabling comparison of productivity levels and trends over time and between networks. We use these PIN techniques for our:
  - Time-series multilateral TFP and capital and opex multilateral PFP. TFP and capital and opex PFP results are used in this report to measure and compare changes in the productivity level of a single entity over time (i.e. whether productivity of the distribution industry as a whole or an individual DNSP has increased or decreased over time).
  - Panel data MTFP and capital and opex MPFP. MTFP and capital and opex MPFP results are used in this report to measure and compare changes in 'relative productivity' over time (i.e. whether a given DNSP has a higher or lower productivity level relative to other DNSPs at a point in time and over time).
- **Econometric opex cost function models.** These estimate opex (as the input) as a function of outputs and some other operating environment factors to measure opex efficiency.
- **Partial performance indicators (PPIs).** These simple ratio methods relate one input to one output. In this respect they are partial efficiency measures. We use PPIs to examine relative performance across DNSPs.

Being top-down measures, each benchmarking technique cannot readily incorporate every possible exogenous factor that may affect a DNSP's performance. Therefore, the performance measures are reflective of, but do not precisely represent, the underlying efficiency of DNSPs. For this benchmarking report, our approach is to derive 'raw' benchmarking results and where possible, explain drivers for the performance differences across DNSPs and changes over time. These include considering those material operating environment factors (OEFs) that may not have been accounted for in the benchmarking modelling (see section 7).

The time-series and panel data based PIN techniques used in this report both rely on multilateral productivity indexes. The indexes allow comparisons of absolute levels and growth rates of the measured productivity. MTFP examines the overall productivity of using all inputs in producing all outputs. Opex or capital MPFP examines the productivity of either opex or capital in isolation. The econometric opex cost function models also examine the productivity of opex in isolation.

What is multilateral total factor productivity?

TFP is a technique that measures the productivity of businesses over time by measuring the relationship between the inputs used and the outputs delivered. Where a business can deliver a given level of outputs using less inputs, this reflects an increase in its productivity. MTFP and MPFP analysis allows us to extend this to compare productivity levels between networks.

The inputs we measure for DNSPs are:

- Five types of physical capital assets DNSPs invest in to replace, upgrade or expand their networks.

- Opex to operate and maintain the network.

The outputs we measure for DNSPs (and the relative weighting we apply to each) are:

- Customer numbers. The number of customers is a driver of the services a DNSP must provide (about 19% weight).
- Circuit line length. Line length reflects the distances over which DNSPs deliver electricity to their customers (about 39% weight).
- Ratcheted maximum demand (RMD). DNSPs endeavour to meet the demand for energy from their customers when that demand is greatest. RMD recognises the highest maximum demand the DNSP has had to meet up to that point in the time period examined (about 34% weight).
- Energy delivered. Energy throughput is a measure of the amount of electricity that DNSPs deliver to their customers (about 9% weight).
- Reliability (Customer minutes off-supply). Reliability measures the extent to which networks can maintain a continuous supply of electricity (customer minutes off-supply enters as a negative output and is weighted by the value of customer reliability).

The November 2014 Economic Insights report referenced in Appendix A details the rationale for the choice of these inputs and outputs. Economic Insights updated the weights applied to each output in November 2018 and again in November 2020, which are used by Quantonomics in producing this year's results.

To assist with the ability to understand these inputs and outputs, as well as how they are used in the benchmarking analysis, we have provided some further detail in relation to these variables.

In terms of the inputs being used in the benchmarking analysis:

- The capital inputs, such as transformers, overhead lines and underground cables, measure the physical quantity of the assets (e.g. capacity × kilometres of overhead lines or capacity of transformers). This is used as a proxy for annual capital service flow as we assume relatively constant flow of services over the life of an asset, and thus that the annual flow is proportionate to capital stock.
- The opex input reflects the costs associated with the labour, materials and services that are purchased and consumed in a given year. These costs are deflated by a price index of these inputs to establish a quantity measure of opex.

At the start of the benchmarking program there was general agreement that outputs should be included on a functional rather than billed basis. This reflects that under the building block model approach to regulation there is not typically a direct link between the revenue requirement and how a DNSP structures its prices.[9] It was also noted that the outputs included should reflect services provided directly to customers, rather than activities undertaken by the DNSP which do not directly affect what the customer receives. In terms of the outputs being used in the benchmarking analysis and the services provided:

- Customer numbers provides a measure of the services and benefits ultimately provided to end users of the distribution networks regardless of how much they consume. It is an indicator of network complexity and connectivity.
- Circuit length reflects the geographic distribution of customers that DNSPs need to construct networks to connect in order to deliver energy. In combination with customer numbers, these variables will reflect the impact of different levels of end user density within an area on distribution costs.
- Ratcheted maximum demand reflects the (non-coincident) maximum demand from customers on the distribution network. The highest system peak demand observed in the period (up to the year in question) is used to give credit for the provision of capacity to meet higher maximum demand in the earlier years.
- Energy throughput reflects the energy delivered to customers.
- Reliability (Customer Minutes Off-Supply) reflects the extent to which networks are able to maintain a continuous supply of electricity.

Appendix A provides reference material about the development and application of our economic benchmarking techniques. Appendix B provides more information about the data required. Our website also contains this year's benchmarking report from our consultant Quantonomics and the benchmarking data and results files.

1.2 Updates in this benchmarking report

The 2024 Annual Benchmarking Report largely uses the same methods as set out in previous reports. The main methodological change in this year's report relates to the underlying basis for how the capital inputs (outlined above) are weighted.

The capital inputs are weighted using the AUC of capital, which reflects the cost DNSPs face relating to capital inputs, i.e. asset costs.[10] In our initial calculations, we observed sharp declines in the AUC for different capital inputs and in some instances, negative AUCs. Our analysis indicated these outcomes were driven by rapid changes in the inflation environment and growing divergence between actual inflation and the long run expected inflation used in the AUC calculation. These changes were material enough to drive changes in the productivity results that would not be related to movements in efficiency.

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9 The AER generally sets the revenue requirement and then separately prices are set in order to recover this revenue requirement.

10 The AUC of capital is the return on and return of the regulatory asset base and the benchmark tax liability component.

To address these issues, and derive more stable AUCs which still reflect movements in fundamentals, we have made the following methodological refinements to the AUC calculation:

- Moving from using a nominal Weighted Average Cost of Capital (WACC) to a real WACC
- Removing the inflation addition term from the calculation of regulatory depreciation
- Moving from a fixed 2.5% expected inflation rate to calculating expected inflation based on Reserve Bank of Australia (RBA) forecasts.

The end impacts of these refinements on the historical PIN results are minor, reflecting that on a period-average basis, the relative shares of opex and the AUC see limited changes as a result of these methodological refinements. We consulted the DNSPs on these refinements and received broad support for them. More detail on the methodological refinements and the impact of these changes are in Appendix C.

We also finalised implementing the method to address capitalisation differences. To do this we sought DNSPs' views on the preliminary method used in the 2023 Annual Benchmarking Report and whether we should continue presenting results using both the previous method and the capitalisation adjusted approach. DNSPs expressed support for only reporting results adjusted for capitalisation differences and for retaining the method previously implemented. This involved removing the CCO component of capex from each year in the AUC calculations, and constructing a separate regulatory asset base (RAB) series for each network accounting for these adjusted yearly capex amounts. We use reported CCOs in each year, reflecting the prevailing cost allocation method (CAM) at the time. This recognises that capex reflects the CAM at that time and ensures consistency with the CCOs that would have been embedded in each year's capex, and added to the RAB.

As only the capitalisation adjusted results are presented, the results in this report are not directly comparable with those in previous reports other than the 2023 Annual Benchmarking Report. This 2023 report contained more limited results using the preliminary method to address capitalisation differences.

In relation to benchmarking data, this year we have continued adjusting data relating to non-recurrent Software as a Service (SaaS) costs[11] and lease costs. We began adjusting historical SaaS and lease data in the 2023 Annual Benchmarking Report after considering potential inconsistencies. Our benchmarking relies on the assumption that data is reported consistently across DNSPs in accordance with instructions provided with our Regulatory Information Notice (RIN) templates. For this reason, our position on non-recurrent SaaS and lease costs is that they should be considered under legacy accounting standards and guidance for the purpose of benchmarking until a future date when most or all DNSPs have

11 These costs are relevant to the setup and implementation of SaaS systems.

transitioned onto current accounting standards and an approach to recasting the historical cost to be on a consistent basis has been determined.

We are currently aware that Jemena, AusNet and Essential Energy have either fully or partially adopted the new accounting standards / guidance in the years up to and including 2022–23. Through consultation with these DNSPs in 2024, and further to any adjustments provided in the preparation of last year's report:

- Jemena provided adjusted 2022–23 data which reports non-recurrent SaaS implementation costs under the legacy standard (as capex rather than opex). This resulted in decreased opex and an increase to its RAB.
- AusNet provided adjusted 2022–23 data under the legacy standards which reports non-recurrent SaaS costs as capex and any lease costs as opex. The magnitude of SaaS costs was greater than that of lease costs resulting in a net decrease to opex and an increase to the RAB.
- Essential Energy provided adjusted data for the 2019–23 period. It made adjustments to its actual data for the period which it applied the current accounting standard for leases.[12] The adjustments resulted in lower RAB in each year of this period and higher opex, reflecting the legacy accounting standard for leases.

We will continue to monitor the basis on which non-recurrent SaaS and lease costs are reported by DNSPs, while consulting with individual DNSPs in circumstances where we require adjusted data to maintain consistency. We anticipate that the reporting of non-recurrent SaaS and leases will vary between businesses until at least 2026–27. At this point, or earlier, we will consult networks on the preferred approach to the future reporting of these costs for benchmarking purposes, with a view to maintaining consistency across businesses and across the full time series.

This report also includes a number of other minor updates in the benchmarking data. These updates reflect refinements to the current and historical Australian DNSP dataset, consistent with previous years' benchmarking reports, and are set out in the consolidated benchmarking dataset published on our website.[13]

1.3 Benchmarking development program

We operate an ongoing transparent program to review and incrementally refine elements of the benchmarking methodology and data. This includes where necessary considering if, and how, the changing environment DNSPs operate in (the broader economy and within the context of the energy transition) impacts the benchmarking methodology and data.

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12 This treatment of leases in the reporting of actual data accords with Essential Energy's 2019–23 regulatory determination, but results in an inconsistency for benchmarking purposes.

13 Refinements are outlined in the 'Data revisions' sheet of the consolidated benchmarking data file.

Our benchmarking development program takes into account issues arising across both the distribution and transmission reports. There are a variety of factors, and associated costs and benefits, informing the development work we prioritise and progress, including:

- Feedback from stakeholders, which can often contain a range of views
- The materiality and impact of the development work and potential for errors on the robustness of the benchmarking
- The materiality and impact of the development work in relation to upcoming revenue determinations in which the benchmarking results will be used
- The ability to progress this work, including any sequencing issues and data availability
- The resources available to undertake this work.

With this development work often being complex, we exercise judgement in coming to a realistic view on relative priorities. We value the stakeholder feedback provided in relation to development issues. This contributes to our thinking and ongoing improvement in the benchmarking, even in instances where we do not necessarily agree with points raised or adopt these specific suggestions.

This year we progressed three development issues:

- We completed a review of the non-reliability output weights used in the TFP and MTFP benchmarking techniques. The outcomes of this review, undertaken by the University of Queensland's Centre for Efficiency and Productivity Analysis (CEPA), are set out in section 8.1.
- We fully implemented our approach to addressing capitalisation differences in DNSP benchmarking, as noted in section 1.1, and set out in section 8.2.
- We further considered possible options to improve the performance of the Translog econometric opex cost function models, reflecting ongoing monotonicity issues and the more recent issue of non-convergence. This is discussed further in section 8.3, including the consultation we are initiating alongside the publication of this report.

We are also continuing to monitor the availability of export service-related data that could be used to inform a future review, which we said we would commence by 2027 in the context of our review on incentivising and measuring export service performance.[14]

In the following years we will additionally prioritise examining the choice of the benchmark comparison point used to examine the efficiency score results from the econometric opex cost function models. This is used in the context of revenue determinations when assessing the efficiency of DNSPs' opex. It is likely we will commence this after the conclusion of the next 'round' of revenue determinations, i.e. from 2025–26, after the Victorian DNSP regulatory determinations.

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[14] AER, *Incentivising and measuring export service performance – Final Report*, March 2023.

We will also consider other incremental improvements as our resourcing permits, including as part of the preparation of the annual benchmarking reports and as specifically raised in revenue determinations. This includes OEFs and other issues as they arise, such as the impact on benchmarking of the newly added National Energy Objective in relation to emissions reduction.

More detail on our benchmarking development work is contained in section 8.

1.4 Consultation

In developing this report, we consulted with external stakeholders in two stages. Firstly, in relation to the preliminary benchmarking results and report prepared by our consultant, Quantonomics. Secondly, in relation to a draft of this year's Annual Benchmarking Report. As noted in section 1.3, we value the stakeholder feedback and the benefits it can bring.

The feedback we received, and our responses, are as follows.

1.4.1 Refinements to the AUC of capital methodology

As set out in section 1.2, feedback on the refinements to the AUC methodology was largely positive, with TasNetworks, Essential Energy, Ausgrid and AusNet supporting the changes.[15]

TasNetworks raised a specific issue in relation to the methodological refinement of the AUC of capital. It suggested that the AUC calculation use expected inflation that aligns with the inflation calculation method in the Post Tax Revenue Model. It considered this would improve standardisation and understanding, but noted the impact of this change would be minimal. We consider the approach we have used is appropriate given it is consistent with the prevailing AER methodology that applied in the respective periods in determining the rate of return. However, we acknowledge the approach suggested by TasNetworks is a possibility, and will consider it as a part of any future AUC refinements.

Ausgrid and Evoenergy both noted that the expected inflation rate for 2022–23 in the AUC calculation appears quite low at 1.9%, while the May 2022 inflation forecast from the RBA and AER glidepath approach imply a forecast of 3.0%. This is due to our approach using lagged RBA forecasts as a starting point in the expected inflation calculation. Our sensitivity testing suggests that the effect of moving to an un-lagged approach is quite small, and we do not expect a material impact on MTFP and MPFP results. We will consider this further as a part of any future AUC refinements.

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15 TasNetworks, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 15 August 2024; Essential Energy, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 22 August 2024; Ausgrid, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 26 August 2024; AusNet, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 26 August 2024.

1.4.2 Addressing capitalisation differences in PIN models

As also set out in section 1.2, feedback on the approach used to address capitalisation differences in the MTFP and MPFP models in the 2023 Annual Benchmarking Report was positive. Stakeholders noted the approach appeared reasonable and well-intended in the context of the simplifying assumptions that had been made.[16] Only minor potential refinements were suggested. We have tested the impact of these refinements, such as removing CCOs from only system asset classes and not non-system asset classes (e.g. motor vehicles, plant and equipment, and IT and communications). We consider the added complexity of these refinements outweighs any minor benefit gained through accuracy in this context. As a result, we have not implemented them.

1.4.3 Output weights in the PIN models

Some DNSPs suggested the output weights used in the PIN models should be updated, including to reflect the approach to address capitalisation differences, as it had been 5 years since the last update and in-light of the review underway.[17] We agree that the output weights should be updated and, as set out in section 8.1, will do this in the 2025 Annual Benchmarking Report as a part of further considering the recommendations from the review of the non-reliability output weights.

1.4.4 Econometric opex cost function development issues

Ausgrid and Evoenergy raised issues relating to the econometric opex cost function models and associated development work, which largely touched on recurring issues raised in previous years.[18] This included:

- concerns about the increasing number of monotonicity violations for the Translog models

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16 Essential Energy, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 22 August 2024; Jemena, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 27 August 2024; AusNet, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 26 August 2024.

17 Jemena, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 27 August 2024; Evoenergy, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 29 August 2024; Essential Energy, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 22 August 2024; Evoenergy, *email to AER – Annual Benchmarking Report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024; Ergon Energy, *email to AER – Annual Benchmarking Report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024; Energex, *email to AER – Annual Benchmarking Report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024.

18 Ausgrid, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 26 August 2024; Evoenergy, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 29 August 2024.

- a suggestion that questionable results were being produced by some of the models as a result of a mis-specification problem. Ausgrid specifically suggested that the lack of a variable capturing the improvement in the opex efficiency of Australian DNSPs (compared to that of New Zealand or Ontario networks) is the key source of misspecification.
- a suggestion that the non-convergence observed in the short period Stochastic Frontier Analysis Translog model may be due to an error in the Stata ado files underpinning the 'xtfrontier' package. The use of modified versions of these ado files was suggested as a potential starting point in understanding the issue at hand.

As noted in section 1.3, we have initiated consultation on possible options to improve Translog model performance alongside the publication of this report. Several DNSPs acknowledged this development work, as outlined in section 8.3.[19] These DNSPs were broadly supportive of our incremental approach and expressed an interest in the results and/or a wish to engage with the process.

In relation to the non-convergence of the Stochastic Frontier Analysis Translog model in the short period, reflecting the advice of our consultant, Quantonomics, we do not consider the suggested modifications to the Stata ado files[20] that Ausgrid and Evoenergy referred to are appropriate. As explained in the Quantonomics report, this is because with Stata there is no quality assurance provided on the manual modifications made to the code.[21] In addition, despite minimally higher values of log-likelihood being obtained with the modifications made as suggested, when tested the resulting values and distribution of the DNSP efficiency scores were anomalous. We are continuing to investigate potential solutions to address the non-convergence, as set out in section 8.3. Given the non-convergence, the results from this model are not presented in section 5.

1.4.5 Other benchmarking development issues

Essential Energy noted the material impact of legislative bushfire obligations in NSW and reiterated a request for the AER to develop a specific OEF based on bushfire obligations in NSW. It also considered a holistic review of the entire input / output methodology would be appropriate, particularly in light of a rapidly changing energy environment and in the context

[19] Ausgrid, *email to AER – Annual Benchmarking Report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024; Evoenergy, *email to AER – Annual Benchmarking Report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024; Energex, *email to AER – Annual Benchmarking Report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024; Ergon Energy, *email to AER – Annual Benchmarking Report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024.

[20] Two 'ado' programs, ''*xtfrontier_FrontierEconomics.ado*' and '*xtsf_llti_FrontierEconomics.ado*', were provided in the context of the Evoenergy 2024–29 revenue determination that reflect the changes suggested by Ausgrid and Evoenergy. These are modifications of the official Stata files ''*xtfrontier.ado*' and '*xtsf_llti.ado*' (the latter using the former).

[21] Quantonomics, *Economic Benchmarking Results for the Australian Energy Regulator's 2024 DNSP Benchmarking Report*, October 2024.

of a transition to net zero.[22] Essential Energy additionally noted its preference for us to minimise the number of revisions and methodology changes in order to provide users with a greater degree of trust in the information included in our Annual Benchmarking Reports.

Ausgrid also recommended a holistic review of the benchmarking models and methodologies.[23] It considered this appropriate given in its view year-to-year changes to the benchmarking framework limit the predictability and consistency of benchmarking process.

AusNet reiterated ongoing concerns around extreme weather events, terrain, vegetation and GSL payments and called for adjustments to be built into the benchmarking while also noting its view that ‘safety’ should be incorporated as an output. Similarly, SA Power Networks supported a review of GSL and emergency response arrangements to understand differences across jurisdictions and the impact this may have on benchmarking.[24]

As noted in sections 1.3 and 8, we are prioritising other specific development issues ahead of refining and adding to our existing OEFs, input or output specifications or considering a holistic review of benchmarking. We believe that our current approach of development work focused on specific issues is a more efficient way of continually improving the robustness of our benchmarking, but note that other issues such as OEFs are progressed in the context of revenue determinations for specific networks. We are committed to continually improving our benchmarking through targeted benchmarking development, data updates and methodological changes where necessary, including with stakeholder consultation.

SA Power Networks noted support for the AER’s collection of export service-related data and encouraged us to undertake the review of export service impacts on benchmarking as soon as adequate data is available.[25] We have committed to undertaking this review in 2027 or earlier if sufficient export service data is available. As discussed in section 8.5, based on the infancy and limited nature of the data available at this stage, we do not believe there is basis for bringing this review forward.

1.4.6 Benchmark comparison point review

Several DNSPs suggested that the review of the benchmark comparison should only occur after significant maturation of our benchmarking approach.[26] This includes after all other

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22 Essential Energy, *email to AER – Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024.

23 Ausgrid, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 26 August 2024.

24 AusNet, *email to AER – Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024; SA Power Networks, *email to AER – Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024.

25 SA Power Networks, *email to AER – Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024.

26 AusNet, *email to AER – Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024; Ergon Energy, *email to AER –Annual Benchmarking*

outstanding benchmarking development issues are resolved. Evoenergy further expressed disagreement with our long-standing view that the current benchmark comparison point is conservative and accounts for uncertainty. We have indicated that we will commence this review from 2025–26 (section 8.4) and will examine these arguments and concerns in the context of preparing for this review.

1.4.7 Data updates and adjustments

A number of networks raised potential discrepancies and errors in the dataset.[27] Errors identified that we have confirmed and corrected include:

- incorrect CCOs used for Ausgrid in the AUC of capital calculation between 2009–18 and 2023
- TasNetworks' total circuit length was not updated following updates to disaggregated circuit lengths in 2023
- AUCs in the *DNSP AUC calculation (2023)* file did not match the AUCs present in the *DNSP consolidated benchmarking data (2023)* file.

These data updates did not result in material changes to the DNSP benchmarking results.

Ausgrid noted an additional data error relating to the CCOs in its 2023 benchmarking opex which we have not corrected for in the 2024 Annual Benchmarking Report.[28] This error results in a minor 0.1% overstatement of Ausgrid's opex in 2023. Given the timing of the error being identified and the low materiality of this data error, we will correct this in preparation for our 2025 Annual Benchmarking Report. We have noted the minor impact of the error in section 4.

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report 2024 – Electricity distribution network service providers – Consultation stage 2, 29 October 2024; Energex, *email to AER – Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024; Evoenergy, *email to AER – Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024.

27 Ausgrid, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 26 August 2024; Evoenergy, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 29 August 2024; TasNetworks, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 15 August 2024; AusNet, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 26 August 2024; Ergon Energy, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 27 August 2024; Energex, *email to AER – Preliminary Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 1*, 27 August 2024.

28 Ausgrid, *email to AER – Annual Benchmarking Report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024.

SA Power Networks expressed support for our approach to adjust for non-recurrent SaaS reporting differences in the short term, while noting its preference for removing non-recurrent SaaS costs from the benchmarking data as a solution in the long term. As noted in section 1.2, we plan on consulting DNSPs on the ongoing future treatment of non-recurrent SaaS and lease costs at or nearer to the point at which all DNSPs have moved onto the current reporting guidelines / standards.

1.4.8 Drafting improvements

We received feedback related to improving the drafting and clarity of specific sections of our 2024 Annual Benchmarking Report and accompanying fact sheet.[29] In response to these suggestions, we have made minor clarifying changes to the report and fact sheet.

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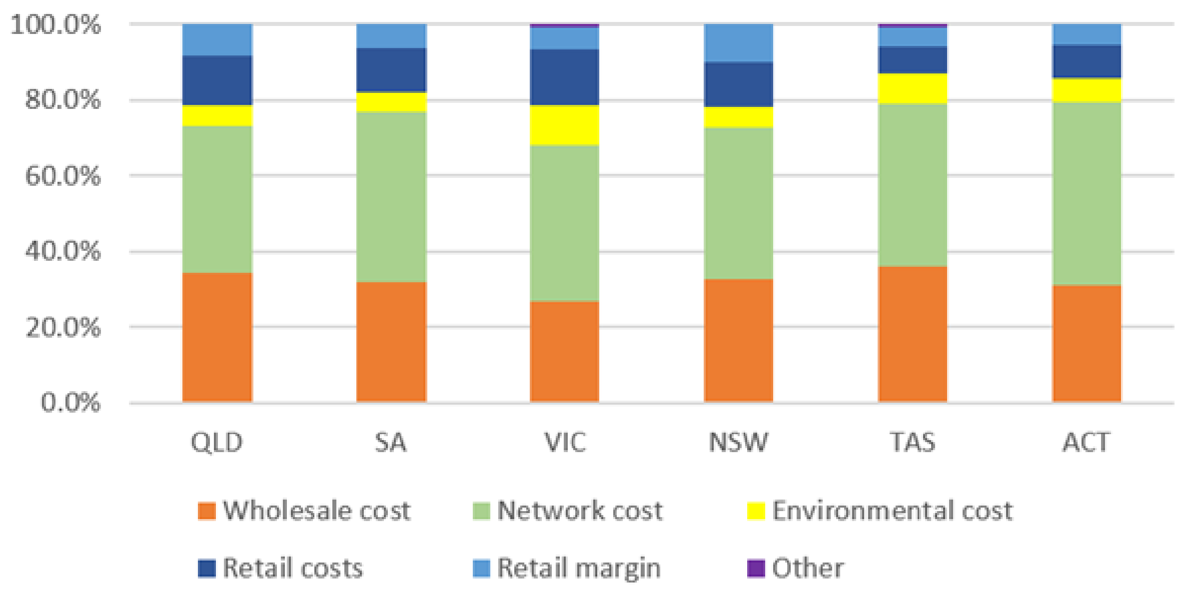
29 Energy Users Association of Australia, *email to AER – Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024; Ausgrid, *email to AER – Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024; Essential Energy, *email to AER – Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024; Energy Networks Australia, *email to AER – Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 2*, 22 October 2024; SA Power Networks, *email to AER – Annual Benchmarking report 2024 – Electricity distribution network service providers – Consultation stage 2*, 29 October 2024.

2 Why we benchmark electricity networks

Electricity networks are 'natural monopolies' that do not face the typical commercial pressures experienced by businesses in competitive markets. They do not need to consider how and whether rivals will respond to their prices. Without appropriate regulation, network operators could increase their prices above efficient levels and would face limited pressure to control their operating costs or invest efficiently.

Consumers pay for electricity network costs through their retail electricity bills. Combined distribution and transmission network costs typically account for between 35-45% of what consumers pay for their electricity in most jurisdictions. The remainder covers the costs of generating electricity, retailing, as well as various regulatory programs related to environmental policies. Figure 5 provides a cost breakdown of the typical electricity retail bill. Network costs in Figure 5 cover both the transmission and distribution costs. Based on historical data, distribution costs account for a larger proportion (around 75%) of the network costs compared to transmission costs (around 25%).[30]

Figure 5 Network costs as a proportion of residential electricity bills, 2022–23



Source: AER, *Default market offer prices 2022-23 cost assessment model*, 26 May 2022; ESC, *VDO calculation model 2022–23*, 27 May 2022; OTTER, *Approved Aurora Energy 2022 revised proposal period*, 31 May 2022; ICRC, *Retail electricity price recalibration 2022–23: standing offer prices for the supply of electricity to small customers*, 6 June 2022.

30 AEMC, *Residential electricity price trends 2021, Final Report*, November 2021; AER analysis.

Note: Figures may differ slightly from the source due to rounding. Simple averages across the multiple NSW and VIC DNSPs were used to calculate cost proportions. Data for QLD only covers the costs in urban Queensland as data for rural areas as not available. Categorisation of costs vary from state to state, we have assigned the costs to like categories in the creation of Figure 5.

Under the National Electricity Law and the NER, the AER regulates electricity network revenues with the goal of ensuring that consumers pay no more than necessary for the safe and reliable delivery of electricity services. This is done through periodic (5-year) revenue determinations. Each electricity network provides the AER with a revenue proposal outlining its forecast expenditures. The AER assesses and, where necessary, amends each proposal to ensure it reflects efficient costs. On this basis, the AER then sets each network's revenue for the five-year period, which is the maximum amount the network can recover from their customers. This provides a network with the incentive to outperform and improve its productivity over its regulatory period. The lower costs ultimately provide benefits to customers through lower expenditure forecasts in future periods.

The NER requires the AER to have regard to network benchmarking results when assessing and amending network capex and opex, and to publish the benchmarking results in this annual benchmarking report.[31] The AEMC also noted that whilst benchmarking is a critical tool for the regulator, it can also provide consumers with useful information about the relative performance of their electricity Network Service Provider (NSP) to help them participate in regulatory determinations and other interactions with their NSP.[32]

2.1 The uses of economic benchmarking

Economic benchmarking gives us an important source of information on the efficiency of historical network inputs (opex and capital). Importantly, we use the benchmarking results to inform our assessment of proposed network expenditures, and whether they are efficient, when setting the maximum revenues DNSPs can recover from customers. We also use benchmarking to understand the drivers of trends in network efficiency over time and changes in these trends. This can help us understand why network productivity is increasing or decreasing and where best to target our expenditure reviews.[33]

This is particularly relevant for examining the opex revealed in the most recent years prior to a DNSP’s revenue determination process. Where a DNSP is responsive to the financial incentives under the regulatory framework, actual opex should provide a good estimate of the efficient costs required to operate in a safe and reliable manner and meet relevant regulatory obligations. The benchmarking analysis allows us to test this assumption. The results from the econometric opex cost function models are central in this assessment (as presented in section 5) including quantification of material OEFs that are not directly

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31 NER, cll. 6.27(a), 6.5.6(e)(4) and 6.5.7(e)(4).

32 AEMC, Rule Determination, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, *National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p. viii.

33 AER, *Explanatory Statement, Expenditure Forecast Assessment Guideline*, November 2013, pp. 78–79.

incorporated into these models (as presented in section 7). We use the other benchmarking approaches to qualitatively cross-check and confirm these results.

The benchmarking results also provide network owners and investors with useful information on the relative efficiency of the electricity networks they own and invest in. This information, in conjunction with the financial rewards available to businesses under the regulatory framework, and business profit-maximising incentives, can facilitate reforms to improve network efficiency that can lead to lower network costs and retail prices.

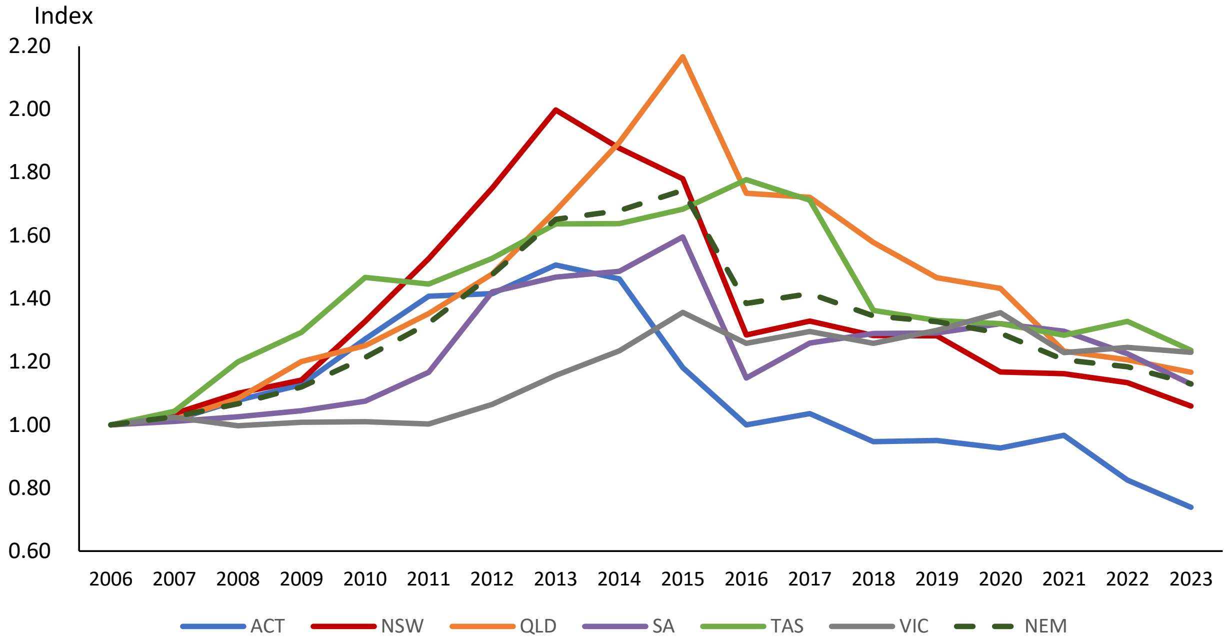
Benchmarking also provides government policy makers (who set regulatory standards and obligations for networks) with information about the impacts of regulation on network costs, productivity and ultimately electricity prices. Additionally, benchmarking can provide information that may contribute to the assessment of the success of the regulatory regime over time.

Finally, benchmarking provides consumers with accessible information about the relative efficiency of the electricity networks they rely on. The breakdown of inputs and outputs driving network productivity allow consumers to better understand what factors are driving network efficiency and provides some visibility of the drivers of the network charges that contribute to their energy bill. This helps to inform their participation in our regulatory processes and broader debates about energy policy and regulation.

Since 2014, we have used benchmarking in various ways to inform our assessments of network expenditure proposals. It has been one contributor to the reductions in network costs and revenues for DNSPs and limiting retail prices or retail price increases, faced by consumers. Figure 6 shows that distribution network revenues (and consequently network charges paid by consumers) have fallen in all jurisdictions in the NEM since 2015. This reversed the increase seen across the NEM from 2007 to 2013, which contributed to the large increases in retail electricity prices.[34] This highlights the potential impact on retail electricity charges of decreases in network revenues flowing from AER network revenue determinations. This includes those informed by benchmarking among a range of factors such as falling cost of capital and lower demand forecasts driving lower capital expenditure.

[34] AER, *State of the Energy Market 2018*, p. 151.

Figure 6 Indexes of distribution network revenues by jurisdiction, 2006–23



Source: Economic Benchmarking RIN; AER analysis.

3 The productivity of the electricity distribution industry as a whole

Key points

- Electricity distribution industry TFP decreased over the 2006–15 period at an average annual rate of 1.4%. Following this, it trended up over the period 2015-23 at an average annual rate of 0.9% per year. This more recent improvement reflected a decline in inputs, primarily the opex input, and consequently improved opex partial factor productivity (PFP). In contrast, the long-term decline in capital PFP has placed constant downward pressure on TFP.
- Over the 2006–23 period, the distribution industry's productivity was higher than that of the broader utilities sector, and lower in comparison to the productivity of the Australian economy.[35]
- Productivity in the electricity distribution industry, measured by TFP analysis, decreased by 2.5% in 2023. This was the largest year-on-year decrease in distribution industry productivity since 2012 and was driven primarily by an increase in opex (contributing −3.2 percentage points to productivity growth in 2023). This was the second consecutive year in which distribution industry TFP decreased, following a 1.3% fall in 2022. Despite these falls, productivity remains around the level it was in 2020.
- The decline in the distribution industry's productivity in 2023 was smaller than the decline in the utilities sector (−4.6%). The productivity of the overall Australian economy declined by 0.8% in 2023, a smaller decline in productivity than observed in the utilities sector and electricity distribution industry.

This section presents the TFP results of the electricity distribution industry from 2006 to 2023 and for the 12-month period to 2023, the latest year of available data. As set out in section 1, TFP results are used in this report to measure and compare changes in productivity, and their drivers, of a single entity (e.g. the distribution industry or a DNSP) over time. Examining trends over time can provide insights, such as to any cycles that exist, which may not be available when only looking at the short-term and particularly changes in a single year. This is due to the volatile nature of some inputs and outputs, which can create noise in

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35 Australian economy productivity and the utility sector productivity are measured by the multifactor productivity indexes (in quality adjusted hours worked basis for the labour input). The market sector consists of 16 industries, the full list of the included industries can be found here: https://www.abs.gov.au/statistics/industry/industry-overview/estimates-industry-multifactor-productivity/latest-release.

the short-term, and that there may be delayed effects of changes in inputs on outputs, particularly for the sticky capital inputs.

The general trend in distribution industry productivity has been positive with TFP increasing 0.9% per year on average since 2015, as can be seen in Figure 7.[36] This followed a downward trend from 2006–15, in which TFP declined by 1.4% per year on average. Changes in inputs were the primary driver of these two observed trends. In particular, the quantity of inputs grew at 2.6% per annum on average between 2006–15, and decreased by 0.3% per annum on average from 2015–23. Output growth was more consistent over the full 2006–23 period, increasing by 0.9% per year on average, with larger than average output growth only having been observed between 2006–10, when it increased by 2.1% per year on average.

In 2023, industry-wide productivity decreased by 2.5%. This was driven by a large increase in the opex input, contributing −3.2 percentage points to TFP. In contrast, the combined contribution of all other inputs and outputs to TFP was positive in 2023 (0.7%). The largest positive contributor to TFP was the reliability output,[37] which contributed 0.9 percentage points. This year's decrease in TFP is the largest since 2012 and follows a 1.3% decline in 2022. Despite these falls, productivity remains around the level it was in 2020.

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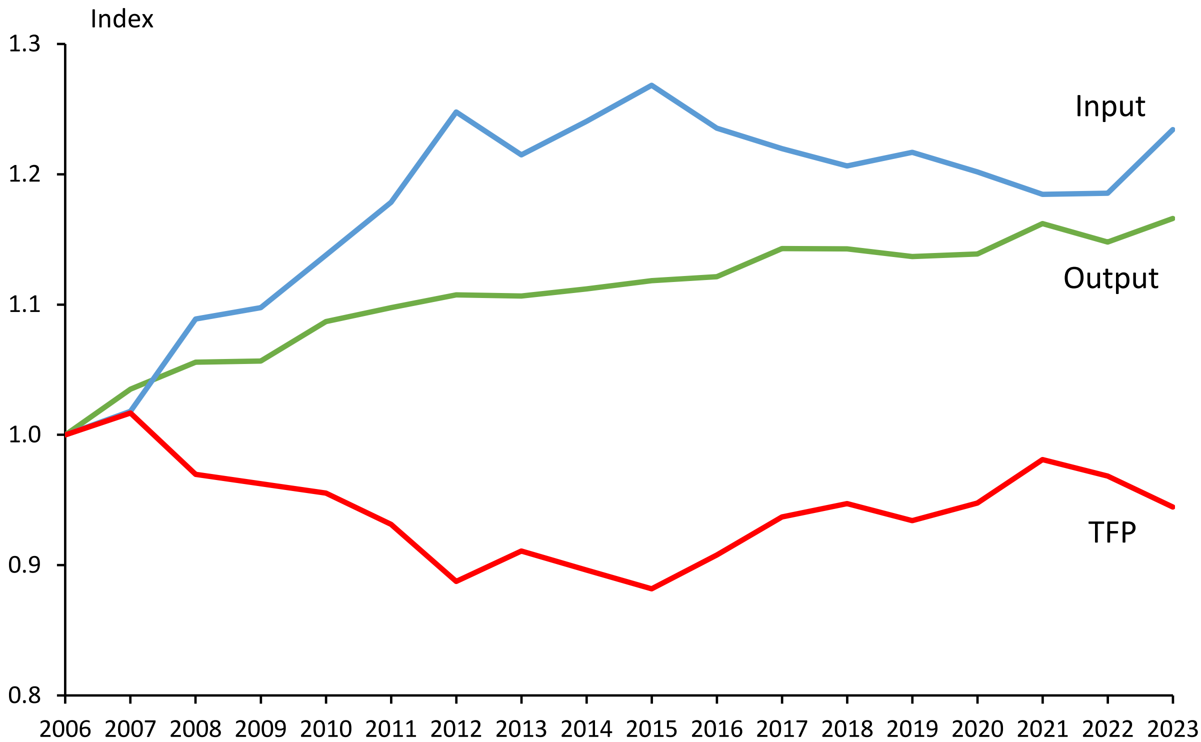
36 The annual rate of change in this report is calculated as a logarithm difference, accounting for compounding effects in continuous time, consistent with the literature on TFP growth.

37 Reflecting a decrease in customer minutes off-supply.

Figure 7 Distribution industry input, output and TFP indices, 2006–23

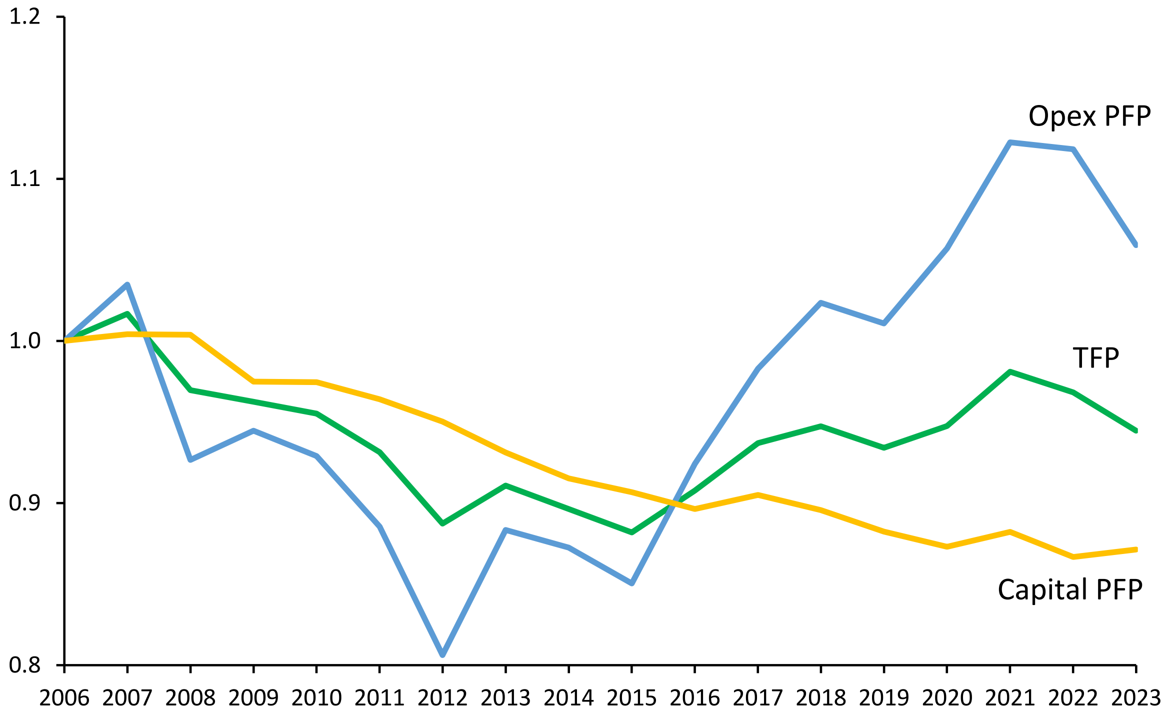


Source: Quantonomics; AER analysis

Figure 8 highlights that the reversal of the declining TFP trend after 2015 was primarily driven by opex PFP rather than capital PFP. Opex PFP reached its minimum in 2012, after which it grew by 2.5% per year on average, with the largest increases occurring between 2015–21. This was during a period of rapidly decreasing opex across the distribution industry. Despite the 5.4% decline in opex PFP in 2023, it is roughly equal to the opex PFP observed in 2020. The sustained growth in opex productivity since 2012, including the effect of the sharp decline in 2023, is considerably higher than the 0.5% per year opex productivity growth assumption for DNSPs that is used in the context of regulatory decisions. While the opex PFP reflects both a degree of 'catch-up' productivity by less efficient DNSPs and changes in the productivity frontier, this is something that we may consider reviewing in the future.

In contrast, capital PFP declined consistently over the full benchmarking period. This is largely driven by capital inputs (particularly transformers and underground distribution cables) growing at a faster pace than key outputs. The steadier nature of this trend when compared to opex PFP is expected, given that the capital inputs used in the model are a stock measure and due to the largely sunk and long-lived nature of DNSP capital assets. We also consider that the long-term decline in capital PFP is comparable to that of some other industries in the Australian market economy and is reflective of a trend of declining capital productivity in developed economies. This may be a consequence of capital deepening, that is, the increase in the amount of capital per worker.[38,39] We, however, note that the TFP outputs considered in benchmarking may not be fully capturing outputs and services provided by networks in relation to export services (see section 8).

Figure 8 Electricity distribution total, capital and opex productivity, 2006–23



Source: Quantonomics; AER analysis.

Figure 9 compares the TFP of the electricity distribution industry over time relative to productivity of the overall Australian economy and utilities sector. There was a growing divergence between the distribution industry and overall Australian economy productivity up to 2015. Over this period, distribution industry productivity largely declined in-line with the productivity of the broader utilities sector. From 2015, however, the distribution industry's productivity growth (0.9% per year on average) exceeded that of the overall Australian economy (0.3% per year on average) and diverged from the declining trend of the utilities sector (−1.6% per year on average). In 2023 the distribution industry's productivity decline of 2.5% was smaller than that of the utilities sector (−4.6%), but larger than the productivity decline of the overall economy (−0.8%).

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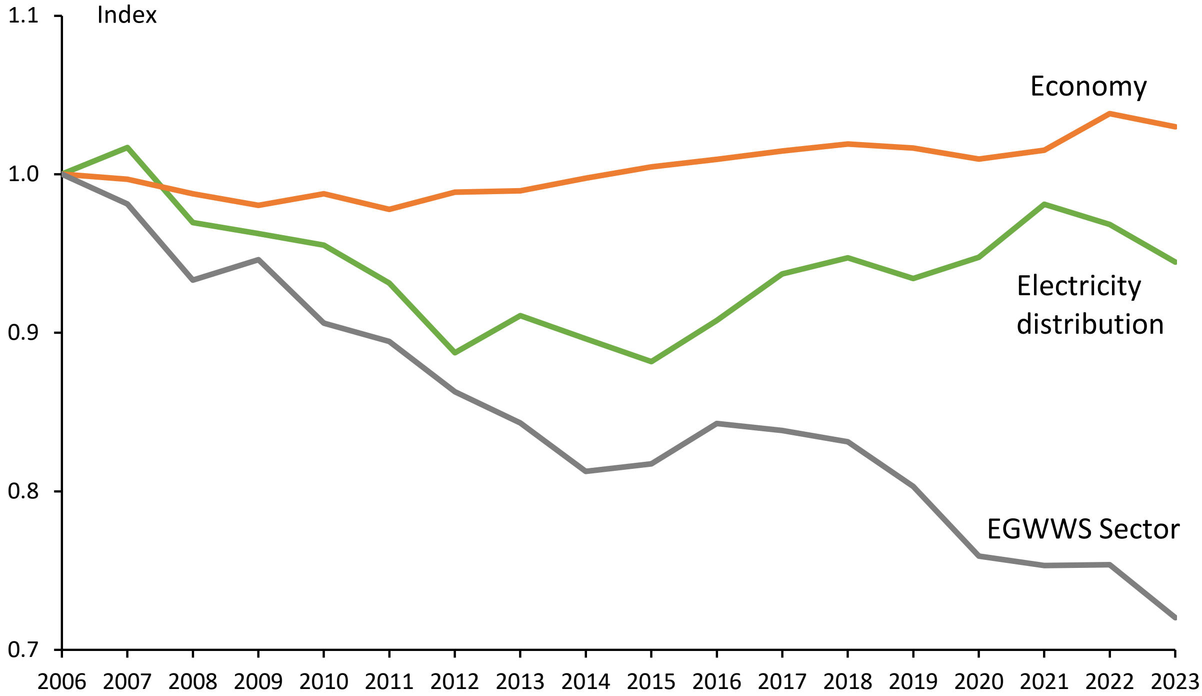
38 Australian Bureau of Statistics, *Tables 1-19: Estimates of Industry Multifactor Productivity*, December 2023.

39 Organisation for Economic Co-operation and Development (OECD), *OECD Compendium of Productivity Indicators 2015*, May 2015, p. 26.

As observed by the Productivity Commission, the utilities sector has seen a long-term decline in productivity beginning in 1997–98. This was as a result of continued capital investment in anticipation of future demand, issues in output measurement, exogenous shifts to higher cost technologies, and unmeasured improvements in output quality such as reliability, safety, visual amenity or lower emissions.[40,41] A cyclical pattern of investment associated with replacing ageing network infrastructure assets may have put downward pressure on recent productivity performance.

Figure 9 Electricity distribution, EGWWS sector, and economy productivity, 2006–23



Source: Quantonomics; AER analysis.

Figure 10 helps us understand the drivers of the change in distribution industry productivity in 2023 by showing the individual contribution of each output and input to the annual change in TFP. The contributions are ordered from the most positive on the left to the most negative on the right. If all the positive (blue bars) and negative contributions (orange bars) are added together, they sum to the TFP change given by the green bar on the right of the figure.

As noted above, opex was the primary input or output driving TFP decline in 2023. It contributed −3.2 percentage points to the TFP change. This reflected increased opex quantity[42] in 2023 for 10 out of the 13 DNSPs. There were no common drivers of increased

40 Productivity Commission, *Productivity in Electricity, Gas and Water: Measurement and Interpretation*, March 2012.

41 Productivity Commission, *Productivity Update*, May 2013, pp. 33–34.

42 This is nominal opex which has been deflated using a combination of CPI and WPI.

opex across the entire industry. However, increases in emergency response costs resulting from weather events, intensified inspection and maintenance programs and increases in vegetation management driven by higher rainfall and jurisdictional regulatory obligations relating to bushfire risk were some of the key contributors to increasing opex for several DNSPs.

Partially offsetting this, the reliability output was the primary positive driver of TFP in 2023, contributing 0.9 percentage points to TFP change. This reflects a reduction in customer minutes off-supply, following a year of particularly poor reliability in 2022. Year to year, the reliability output is volatile in nature, due to its weather dependency.[43] However, the average annual contribution of reliability to TFP has been 0.1% over the 2006–23 period and not a material driver of the observed productivity trends. Given reliability can be volatile we also examine TFP growth excluding reliability. Distribution industry TFP change in 2023 excluding reliability was slightly lower than when it is included (−3.4% and −2.5%, respectively).

All other inputs and outputs combined made a small −0.2 percentage point net contribution to TFP in 2023 and no other input or output contributed more than 0.5 percentage points to increasing or decreasing productivity.

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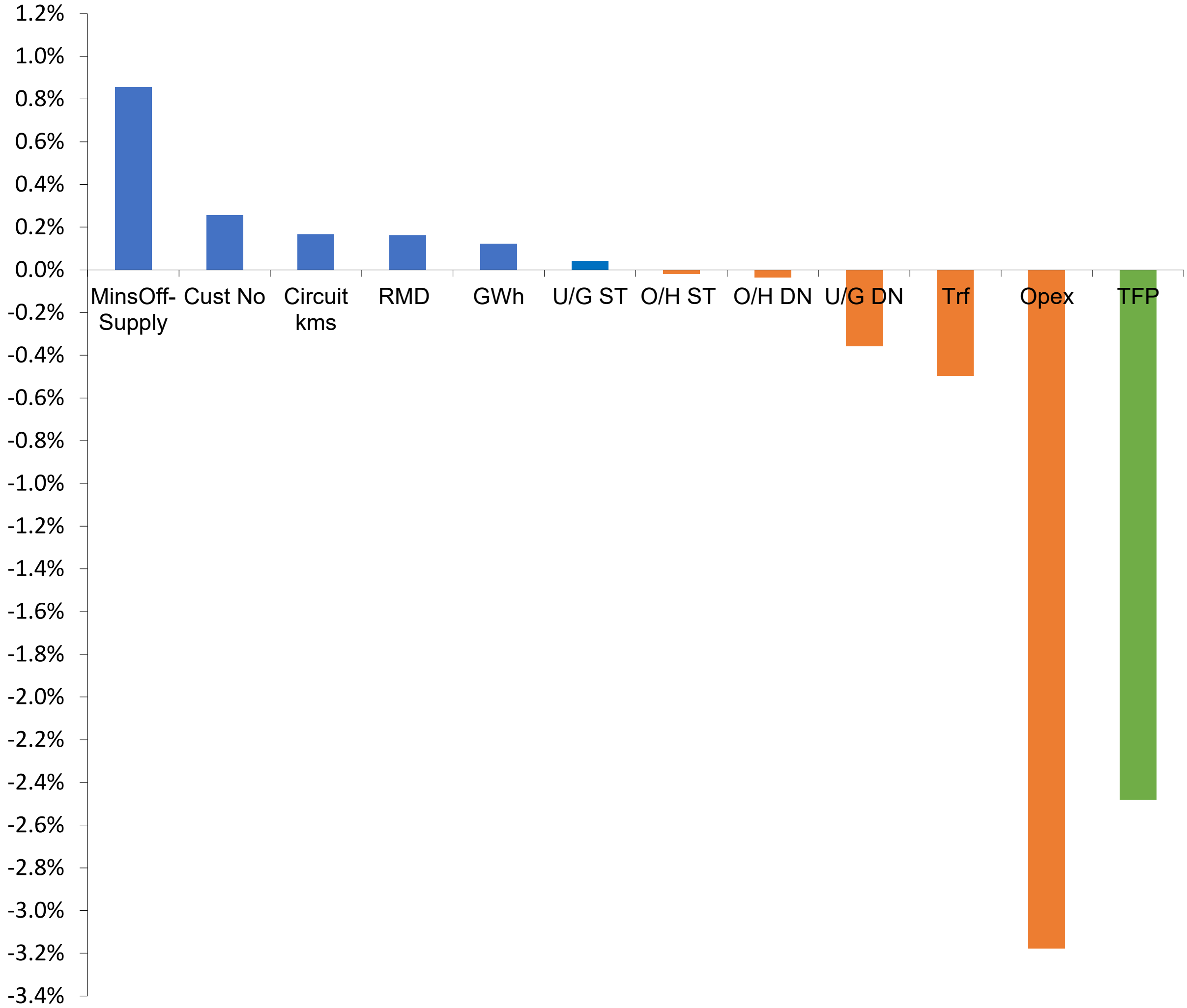
43 Yearly increases and decreases to individual DNSPs' customer minutes off-supply, as well as the aggregate customer minutes off-supply for the distribution industry are driven primarily by the frequency and severity of weather events, particularly storms. Our preferred measure of customer minutes off-supply already excludes the outsized impact of 'major event days' which generally relate to particularly severe storm events.

Figure 10 Electricity distribution output and input percentage point contributions to annual TFP change, 2023



Source: Quantonomics; AER analysis.

4 The relative productivity of distribution network service providers

Key points

We have seen convergence in the relative productivity of DNSPs as measured by MTFP from 2006 to 2023, with a shrinking gap between the most and least productive DNSP over time. This reflects both the improved performance of lower ranked DNSPs and worsening performance of higher ranked DNSPs. Convergence in opex MPFP was the primary driver of the material changes in MTFP, with capital MPFP declining continually for most networks over this period and relatively few changes in the rankings of individual DNSPs.

The majority of networks became less productive in 2023 as reflected by their MTFP results, with the average MTFP score decreasing by 1.7%:

- Only three networks (Evoenergy, TasNetworks and Endeavour Energy) saw increases in their MTFP scores. Evoenergy's MTFP rose by 10.0%, making it the top performing DNSP in terms of MTFP improvement in 2023.
- Of the networks with decreasing MTFP scores, Powercor and SA Power Networks were the worst performers as measured by MTFP change in 2023 (−9.1% and −7.6% respectively).

Decomposing MTFP into its opex and capital MPFP components in 2023:

- The average opex MPFP score decreased by 3.2%, with the most productive DNSPs, SA Power Networks and Powercor being the worst performers (−15.8% and −12.0% respectively). Consistent with their improved MTFP performance, Evoenergy and TasNetworks' opex MPFP scores improved the most by 13.8% and 10.9% respectively.
- Capital MPFP, increased by 0.5% on average in 2023 with Evoenergy being the best performer (7.9%) and AusNet the worst performer (−4.4%) in terms of capital MPFP change.
- Increases in opex, rather than the capital inputs were the primary driver of falling productivity.

The results from the MTFP models include the impact of some OEFs such as customer density, but not all material OEFs. This is important when considering the relative efficiency and rankings between DNSPs, as some DNSPs may have more or less favourable OEFs than their peers and may appear more or less efficient than they otherwise would. Section 7 includes information about the material OEFs driving apparent differences in productivity and operating efficiency between the distribution networks.

This section presents economic benchmarking results as measured by panel data MTFP comparative analysis, which relates total inputs to total outputs and provides a measure of overall network productivity relative to other networks. We provide our analysis at a DNSP level, including key observations on the reasons for changes in the relative productivity of DNSPs in the NEM. This is supported by the corresponding partial factor productivity measures of opex and capital inputs (opex MPFP and capital MPFP).

4.1 MTFP results for DNSPs

Table 1 presents the MTFP rankings for individual DNSPs in 2023 and 2022, the annual growth in productivity in 2023, and the average annual growth in the 2006–23 and 2012–20 periods. These results over time can also be seen in Figure 11 while Figure 12 and Figure 13 show the opex and capital MPFP results over time.

Table 1 Individual DNSP MTFP rankings and annual MTFP growth rates

DNSP	2023 Rank	2022 Rank	Change (2023)	Change (2006–23)	Change (2012–23)
SA Power Networks (SAP)	1	1	−7.6%	−1.6%	−1.4%
CitiPower (CIT)	2	2	−3.0%	−0.3%	0.6%
United Energy (UED)	3 ↑	4	−0.4%	0.1%	1.4%
Endeavour Energy (END)	4 ↑	6	1.3%	−0.4%	0.7%
Essential Energy (ESS)	5	5	−5.9%	−0.1%	1.7%
Powercor (PCR)	6 ↓	3	−9.1%	−0.9%	−1.0%
Ergon Energy (ERG)	7	7	−3.5%	0.4%	0.3%
Energex (ENX)	8	8	−1.2%	−0.3%	0.0%
Jemena (JEN)	9	9	−1.1%	0.2%	1.0%
Evoenergy (EVO)	10 ↑	13	10.0%	0.7%	2.2%
AusNet (AND)	11 ↓	10	−2.1%	−1.0%	−0.7%
TasNetworks (TND)	12	12	2.8%	−1.2%	0.1%
Ausgrid (AGD)[44]	13 ↓	11	−1.8%	0.5%	1.9%

Source: Quantonomics; AER analysis.
Note: All scores are calibrated relative to the 2006 Evoenergy MTFP which is set equal to one. These results do not reflect the impact of a range of material OEFs (see section 7).

In terms of changes to DNSPs' MTFP over the 2006–23 period, the most notable increases were for Evoenergy (0.7% per year on average) and Ausgrid (0.5% per year on average). This reflects the improved performance of lower ranked DNSPs. The most significant decreases were for SA Power Networks (−1.6% per year on average), TasNetworks (−1.2%

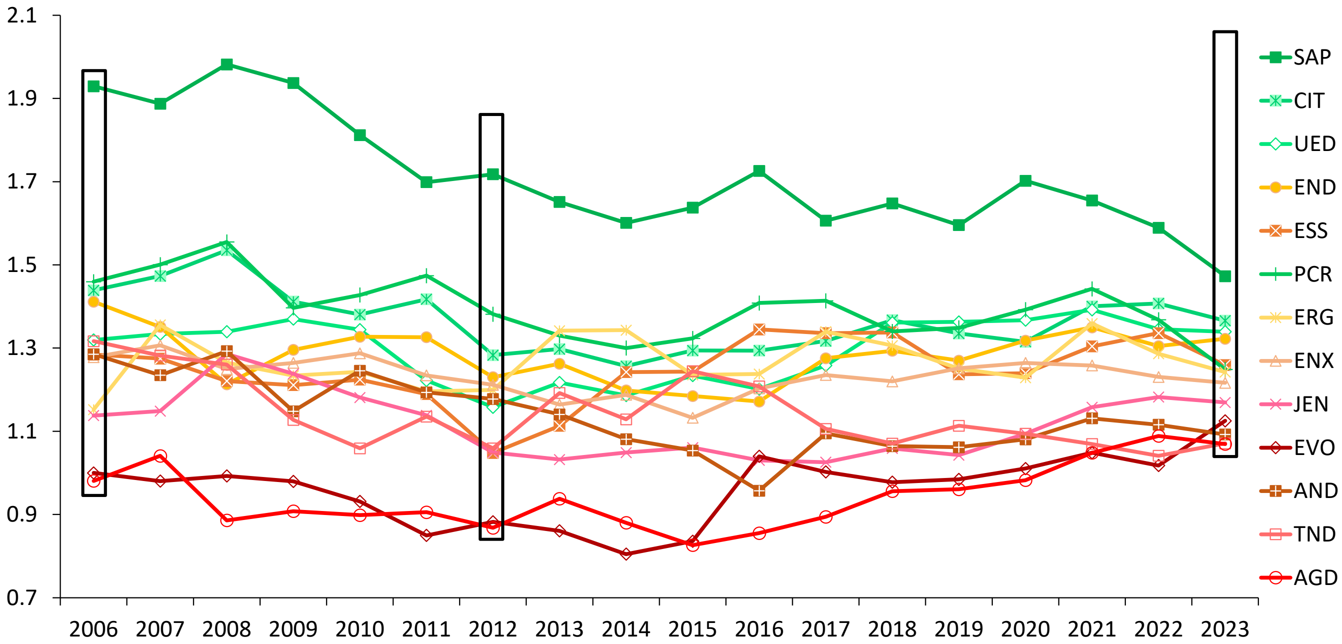
44 As noted in section 1.4, Ausgrid's 2023 opex is currently overstated by 0.1% due to a data error, resulting in these results showing somewhat worse performance. Given the small size of the error, the impact on Ausgrid's productivity performance is not material. However, correction of the error will close the relatively small gap in MTFP score to TasNetworks, which is ranked 12th.

per year on average), AusNet (−1.0% per year on average) and Powercor (−0.9% per year on average) reflecting the worsening performance of some of the higher ranked DNSPs.

We observe a number of changes to the DNSP MTFP rankings and scores in 2023. Most notable were:

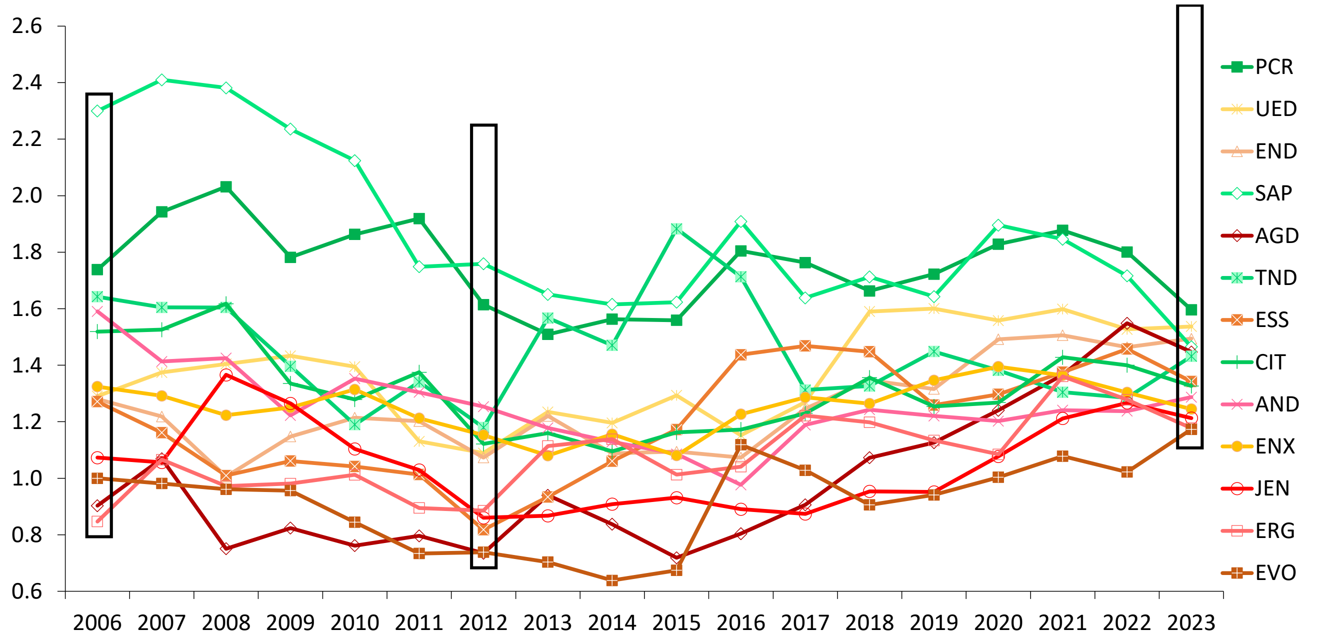
- Powercor's drop from 3rd to 6th driven by the largest observed decline in MTFP (−9.1%)
- Evoenergy's rise from 13th to 10th driven by the largest increase in MTFP (10.0%)
- SA Power Networks' MTFP decrease (−7.6%). It remains the top ranked DNSP which reflects the large lead it has historically held when compared to other DNSPs.

Figure 11 Individual DNSP MTFP indexes, 2006–23



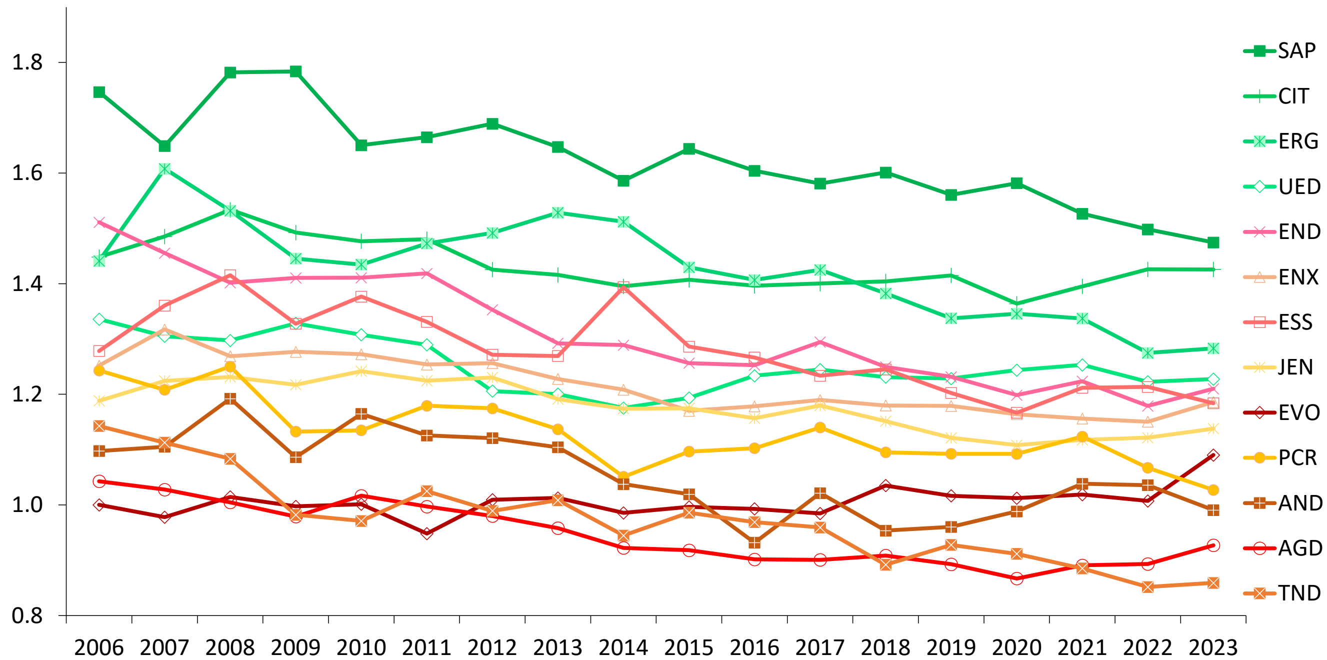
Source: Quantonomics; AER analysis.

Figure 12 Individual DNSP opex MPFP indexes, 2006–23



Source: Quantonomics; AER analysis.

Figure 13 Individual DNSP Capital MPFP indexes, 2006–23



Source: Quantonomics; AER analysis.

4.2 Key observations about changes in productivity

This section describes some of our key observations about changes in the relative productivity of DNSPs over the full benchmarking period, and the latest year, based on the panel MTFP and MPFP results presented in Figure 11, Figure 12 and Figure 13.

4.2.1 Convergence of productivity levels over time

Since 2006 there has been convergence in the productivity levels of DNSPs, both in terms of MTFP and opex MPFP. The spread of productivity levels in 2023 is smaller than in 2012, which was also smaller than in 2006. This can be seen from the increasing clustering of scores within the three equal-sized, black-bordered columns placed in 2006, 2012 and 2023 in Figure 11 and Figure 12. The convergence is due to a number of factors, with the key ones discussed below.

One important factor is that those DNSPs which have been the least productive have improved their performance over time, particularly since 2012. The least productive DNSPs in 2012 as measured by MTFP (Ausgrid and Evoenergy) have increased their productivity at higher rates than some DNSPs within the middle-ranked group. Since 2012, Ausgrid and Evoenergy have increased their overall productivity (MTFP) by 1.9% and 2.2% per year respectively, compared with the industry average of 0.5% per year. The growth in productivity of these DNSPs can be largely attributed to improvements in opex efficiency.

In addition to these DNSPs improving their MTFP performance, several middle-ranked DNSPs have also improved their relative MTFP performance to be closer to the top-ranked DNSPs. In recent years this includes Essential Energy, Jemena and Endeavour Energy, again reflecting improved opex efficiency. Since 2012, the NSW and ACT DNSPs have been among the most improved in the NEM in terms of MTFP and opex MPFP performance under both approaches.

A further driver of increasing convergence in MTFP is that top ranked DNSPs have seen declining MTFP since 2006. A notable example of this trend is SA Power Networks which since 2006 has seen its MTFP decrease by 1.6% per year on average. Despite this decline, SA Power Networks remains a clear standout in MTFP over the entire 2006–23 period, due to its high capital MPFP relative to other networks. Other DNSPs that have been ranked in the top 3 at various points over the 2006–23 period such as Powercor and Ergon Energy now reflect productivity levels that place them mid-field.

Changes in relative opex productivity as measured by opex MPFP are the main driver of productivity convergence. There has been an upward trend in opex MPFP since 2012 as seen in Figure 12, with 11 out of the 13 DNSPs (all bar Powercor and SA Power Networks) increasing their opex productivity. In contrast, as is seen in Figure 13, relative capital productivity as measured by capital MPFP has consistently declined since 2006 and there has been little convergence. The consistent decline in capital MPFP for most DNSPs is not dissimilar to the long-run trend of capital productivity decline in some other industries resulting from capital deepening, that is, the increase in the amount of capital per worker.[45] The only DNSP that has a higher capital MPFP in 2023 as compared to 2006 is Evoenergy. This is only marginally different when comparing 2023 to 2012.

[45] Australian Bureau of Statistics, *Tables 1-19: Estimates of Industry Multifactor Productivity*, December 2023

4.2.2 Opex was the main driver of productivity changes in 2023

As noted in section 3, opex change was the primary driver of changes in the productivity of the electricity distribution industry in 2023. This observation also holds for the relative productivity levels of individual DNSPs.

In 2023 Evoenergy's MTFP increased by 10.0%, which was the largest increase in MTFP and was driven primarily by a reduction in its opex input (−5.2%). In contrast, the opex input increased by 7.0% across the distribution industry. Evoenergy's reduction in opex, paired with a large increase in output due to higher ratcheted maximum demand, resulted in a 13.8% increase in Evoenergy's opex MPFP.

Other DNSPs which had increases in MTFP in 2023 (TasNetworks and Endeavour Energy) also saw increases to their opex MPFP (10.9% and 2.1% respectively). TasNetworks' increase in opex MPFP was driven by an opex input reduction (−7.6%) mainly attributed to greater efficiencies in maintenance, and a reduction in guaranteed service level payments due to improved reliability.[46] In contrast, Endeavour Energy's opex MPFP increase was driven by an increase in outputs (3.2%) paired with a comparatively small (1.0%) increase in opex.

The DNSPs which saw the largest falls in MTFP in 2023, Powercor and SA Power Networks further illustrate that opex was the main driver of productivity change in this period. Powercor and SA Power Networks reported 11.4% and 15.1% increases in their opex inputs in 2023, which were both materially higher than the industry average. These increases drove opex MPFP reductions of 12.0% and 15.8% respectively. SA Power Networks' increase in opex input in 2023 was the largest in the industry and was driven primarily by emergency response costs and guaranteed service level (GSL) payments relating to significant storms in November 2022 and the Murray River flood event from November 2022 to February 2023.[47,48] Powercor's opex increase in 2023 mainly resulted from Energy Safety Victoria compliance driven increases in vegetation management and an increase in maintenance costs due to higher volume and labour costs.[49]

In contrast, capital inputs such as sub-transmission lines and transformers played a more minor role in driving the MTFP changes in 2023. Evoenergy's capital inputs rose slightly by 0.3%, resulting in a 7.9% increase in capital MPFP when paired with its large increase in output. While this increase was the largest in the industry, it was a smaller contributor to MTFP compared to the comparatively large increase in Evoenergy's opex MPFP. Powercor's and SA Power Networks' capital inputs rose by 2.1% and 1.0% respectively and resulted in 3.8% and 1.6% decreases in capital MPFP. These decreases were significantly less

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46 TasNetworks, *Email to AER – Response to questions on 2023 EB RIN data*, April 2024.

47 There were no guaranteed service levy payments applicable to the Murray River flood event as these were excluded from the scheme under the state emergency declaration.

48 SA Power Networks, *Email to AER – Response to questions on 2023 EB RIN data*, April 2024.

49 Powercor, *Email to AER – Response to questions on 2023 EB RIN data*, April 2024.

influential on the overall MTFP of these DNSPs when compared to the opex MPFP changes discussed above.

4.2.3 Interpreting the results

As noted above, and explained further in sections 7 and 8, these results should be interpreted with a level of caution. There are inherent limitations with all benchmarking exercises, including with respect to model, input and output specification and data imperfections. In addition, the results do not reflect the impacts of a range of material OEFs. We recognise these limitations in the conservative way we interpret and apply our benchmarking results to particular DNSPs in the context of revenue determinations. However, we consider that the productivity trends we observe for the electricity distribution industry are consistent with our general expectations.

As discussed in section 8, improving our quantification of material OEFs remains an area of benchmarking development along with fully capturing all of the outputs related to export services. That said, we consider our MTFP model accounts for differences in DNSPs' outputs and as a result relevant density factors are accounted for in the output index. We consider the four outputs measured are material drivers of opex and allow for the difference in customer, energy and demand density across DNSPs (reflecting different customer composition). We also note our benchmarking results have found both predominantly rural and urban networks being in the top, middle and bottom ranked groups.

5 Opex econometric models

Key points

- Powercor, SA Power Networks, United Energy, TasNetworks and AusNet are the most efficient DNSPs in terms of opex efficiency scores over both the 2006–23 and 2012–23 periods. They have average econometric efficiency scores above 0.75 (referred to as the benchmark comparators). In the 2006–23 period, CitiPower is also included in this group of top performing DNSPs. These top performing DNSPs have not changed since the 2023 Annual Benchmarking Report.
- Opex efficiency scores from the econometric opex cost function models are mostly consistent with the opex MPFP efficiency scores across both periods.
- The econometric opex cost function models take into account some OEFs (e.g. relevant density factors and some service classification differences for opex and the extent of undergrounding), but do not include other OEFs. It is desirable to further consider OEFs not included in the benchmarking models that can materially affect the benchmarking results. Section 8 includes information about material OEFs driving apparent differences in productivity and operating efficiency between the distribution networks.
- The results from the econometric opex cost function models are central in our assessment of the efficiency of opex revealed in the most recent years prior to a DNSP's revenue determination process.
- We continue to observe some issues with the reliability of the performance of the Translog models. This is an ongoing area of benchmarking development that we discuss in section 8. This year, we have excluded the results of the Stochastic Frontier Analysis Translog model in the 2012–23 period due to the model not converging. We are continuing to investigate the cause of this and potential solutions as part of our Translog development work.

This section presents the results of four econometric opex cost function models that compare the relative opex efficiency of DNSPs. These reflect an average efficiency score for each DNSP over the 2006–23 (long) period and the 2012–23 (short) period. Examining the shorter time period provides a more recent picture of relative efficiency of DNSPs and takes into account that it can take some time for more recent improvements in efficiency by previously poorer performing DNSPs to be reflected in period-average efficiency scores.

The four econometric opex cost function models presented in this section represent the combination of two cost functions (Cobb-Douglas and Translog) and two methods of estimation (Least Squares Econometrics (LSE) and Stochastic Frontier Analysis (SFA)), namely:[50]

- Cobb-Douglas Stochastic Frontier Analysis (SFACD)
- Cobb-Douglas Least Squares Econometrics (LSECD)
- Translog Stochastic Frontier Analysis (SFATLG)
- Translog Least Squares Econometrics (LSETLG).

5.1 Monotonicity requirements

A key economic property required for these econometric opex models is monotonicity, which means that an increase in output can only be achieved with an increase in inputs, holding other things constant. Cobb-Douglas models assume that the response of opex to output changes (output elasticity) is constant across all observations, and so as long as the estimated output coefficients, which reflect the sample-average output elasticity, are positive then this property is satisfied. However, this property may not hold across all the data points in the more flexible Translog models that allow for varying output elasticities.

Before 2018 the results from the Stochastic Frontier Analysis Translog model were not presented in our annual benchmarking reports as this property was not met. In the 2018 Annual Benchmarking Report the Stochastic Frontier Analysis Translog model results were included for the short period as this property was largely satisfied for most Australian DNSPs. Then in the 2019 Annual Benchmarking Report the results for this and the long period were included as again this property was largely met for most Australian DNSPs. In all Annual Benchmarking Reports since 2020 the number of instances where this property was not met became somewhat more prevalent over both the long and short periods.

In this report the number of instances where monotonicity does not hold in the Translog models has increased since last year. This can be seen in Table 2, where in the long and short period the number of monotonicity violations has worsened other than for short period LSETLG model.

50 Further details about these econometric models can be found in the Economic Insights 2014 and 2018 reports (full references are provided in Appendix A).

Table 2 Number of Australian DNSPs for which monotonicity is violated

Model	2023	2022
Long period		
SFATLG	11	5
LSETLG	3	1
Short period		
SFATLG	13	10
LSETLG	6	7

Source: Quantonomics

The majority of cases where monotonicity is not satisfied relate specifically to the elasticity of opex with respect to the customer number output. That is, there is a decrease (instead of an expected increase) in opex in response to an increase in customer numbers. For the Stochastic Frontier Analysis Translog model specifically, we also observe a number of instances where monotonicity violations relate to the ratcheted maximum demand output.

In presenting econometric opex efficiency scores, we have applied the same approach to monotonicity violations as in previous benchmarking reports. Where a majority of a DNSP's observations in a given model violate monotonicity (indicated by a hatched pattern in Figure 14 and Figure 15), we exclude that model's efficiency score in calculating the DNSP's model-average score (the horizontal black lines in these figures). Further, if we observe monotonicity violations for the majority of Australian DNSPs (7 DNSPs or more), then we exclude that particular model's results from the calculation of every DNSP's average efficiency score.

Following this approach, the Stochastic Frontier Analysis Translog model has been excluded from the calculation of the model-average efficiency score for each DNSP in the long period. The Stochastic Frontier Analysis Translog model results for the short period have also been excluded primarily due to the model not converging. That is, the short period Stochastic Frontier Analysis Translog model is not reaching a point of stability where it can make accurate econometric estimation, including predictions in relation to opex efficiency. The issue of non-convergence is described further in section 8 and in appendix C2.2 of the Quantonomics report.[51]

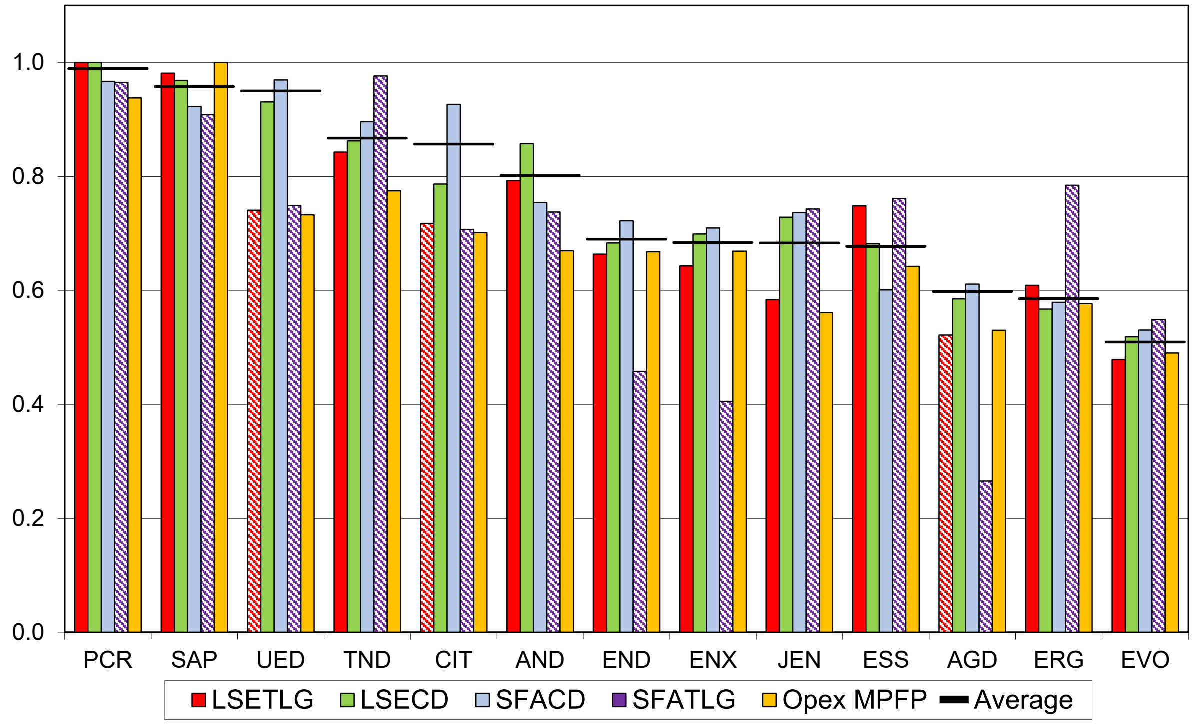
[51] Quantonomics, *Economic Benchmarking Results for the Australian Energy Regulator's 2024 DNSP Benchmarking Report*, October 2024.

5.2 Opex efficiency scores

Figure 14 presents opex efficiency scores for the four econometric models, and model average efficiency scores calculated as described above, over the long period (2006–23). Figure 15 similarly presents opex efficiency scores over the short period (2012–23). Average opex MPFP scores over the long and short period are also shown and corroborate the econometric model-average efficiency scores in most instances. The DNSPs are ranked from highest to lowest in both periods according to model-average efficiency score.

In terms of opex efficiency scores, Powercor, SA Power Networks, United Energy, TasNetworks, CitiPower and AusNet are the benchmark comparators over the long period that we compare other DNSPs against. This reflects that they have average opex efficiency scores above the benchmark comparison point of 0.75 and can be seen in Figure 14.

Figure 14 Econometric opex efficiency scores and opex MPFP, 2006–23

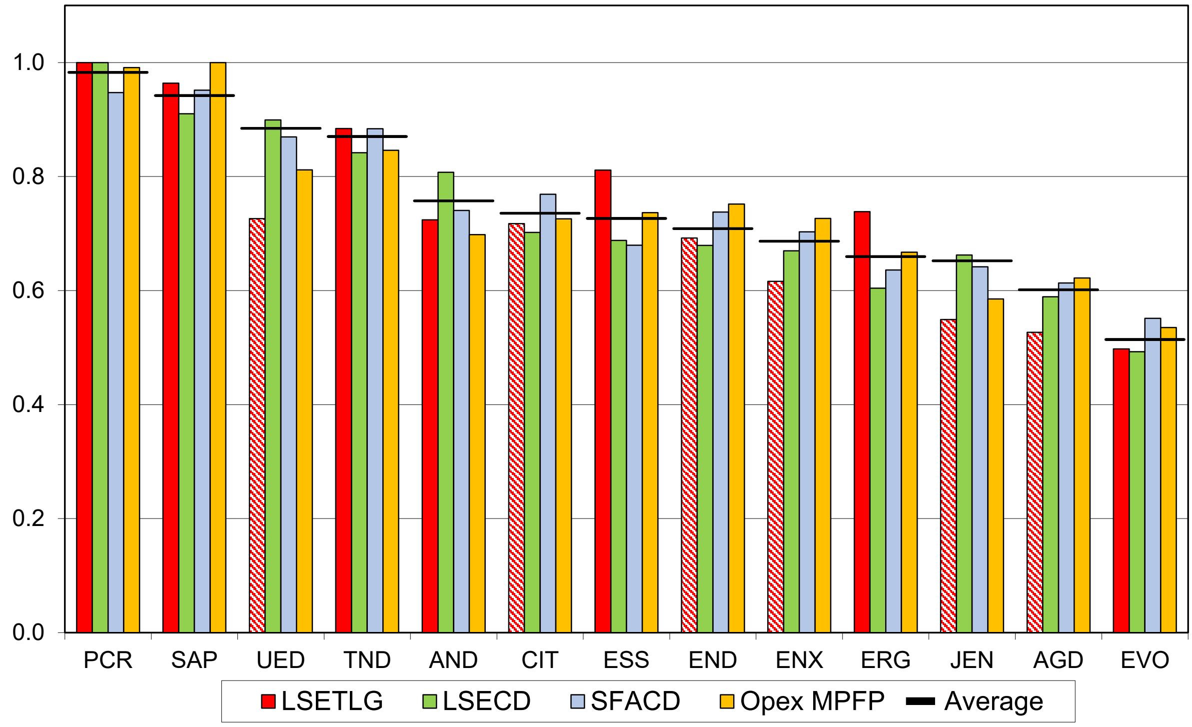


Source: Quantonomics; AER analysis.

Note: Columns with a hatched pattern represent results that violate the key property that an increase in output is achieved with an increase in cost. These results also do not reflect the impact of a range of material OEFs (see section 7). Opex MPFP scores for each DNSP are displayed for comparison and are not included in the calculation of the average efficiency score, which also excludes any results affected by monotonicity violations.

In Figure 15, we see that the same DNSPs are benchmark comparators in terms of opex efficiency scores over the short period, except for CitiPower which has a model-average opex efficiency score just below 0.75 (0.74). There are a number of small differences in rankings and average efficiency scores throughout the middle and lower ranked DNSPs when comparing the long and short period results. This reflects that some of these DNSPs have improved their opex efficiency performance relative to others over recent years.

Figure 15 Econometric opex efficiency scores and opex MPFP, 2012–23



Source: Quantonomics; AER analysis.

Note: Columns with a hatched pattern represent results that violate the key property that an increase in output is achieved with an increase in cost. These results also do not reflect the impact of a range of material OEFs (see section 7). Opex MPFP scores for each DNSP are displayed for comparison and are not included in the calculation of the average efficiency score, which also excludes any results affected by monotonicity violations.

An important limitation of these results is that apart from relevant density factors, service classification differences for opex, and extent of undergrounding, the econometric opex cost function models do not include the impact of all material OEFs. It is desirable to further take into account operating environment conditions not included in the benchmarking models that can materially affect the benchmarking results. Section 7 includes information about material OEFs (such as differences in vegetation management costs) driving apparent differences in estimated productivity and operating efficiency between the distribution networks.

How we use average opex efficiency scores in our revenue determinations to assess relative efficiency of actual opex in a specific year

The econometric opex cost function models produce average opex efficiency scores for the period over which the models are estimated. The results we are using in this section reflect average opex efficiency over the 2006–23 period and the 2012–23 period. Where there are rapid increases or decreases in opex, it may take some time before the period average efficiency scores reflect these changes, in particular for the longer period. This means that in some circumstances the period-average efficiency scores will not reflect a DNSP's relative efficiency in the most recent years.

To use the econometric results to assess the efficiency of opex in a specific year, particularly in the context of our revenue determination processes, we estimate the efficient opex of a benchmark efficient service provider operating in the circumstances of the DNSP in question.

We do this by first averaging the DNSP's actual opex over the relevant benchmarking period (deflated by the opex price index) and calculating its average efficiency score from the models. We then compare the DNSP's opex efficiency score against a benchmark comparison point of 0.75[52] (the best possible efficiency score is 1.0), adjusted for the impact of material OEFs (see the box in section 7 for further detail on how we apply OEF adjustments). Where the DNSP's efficiency score is below the adjusted benchmark score, we adjust the DNSP's average opex down by the difference between the two efficiency scores. This results in an estimate of period-average opex that is not materially inefficient. We then roll forward this period-average opex to a specific base year using a rate of change that reflects the impact of changes in outputs, share of undergrounding and technology between the average year and the specific year. We then compare the DNSP's actual opex in the base year to the rolled forward efficient opex benchmark.

Examples of how we have applied this approach in practice are in the AER's opex draft decision for Ergon Energy for the 2025–30 regulatory period, Evoenergy opex draft decision for the 2024–29 regulatory period and the final decisions for Jemena and AusNet for the 2021–26 regulatory control period, including the application of material OEFs that we have been able to quantify.[53]

52 The benchmark comparators we generally use are those DNSPs that have an econometric model-average efficiency score above the 0.75 benchmark comparison score.

53 AER, *Draft Decision Evoenergy, Regulatory proposal 2024 to 2029, Attachment 6 Operating Expenditure*, September 2023; AER, *Final Decision, Jemena distribution determination 2021–26 - Attachment 6 - Operating Expenditure*, April 2021; AER, *Final Decision, AusNet Services distribution determination 2021–26 - Attachment 6 - Operating Expenditure*, April 2021.

6 Partial performance indicators

Key points

DNSPs with higher customer densities (such as CitiPower, United Energy and Jemena) tend to perform well on 'per customer' metrics. However Powercor (with relatively low customer density) performs more strongly on 'per customer' metrics compared to many DNSPs with higher customer densities.

DNSPs with lower customer densities (such as Essential Energy, Powercor, Ergon Energy and SA Power Networks) tend to perform well on ‘per km’ metrics. However:

- United Energy and Jemena perform well on some 'per km' metrics such as total cost, maintenance and emergency response compared to other DNSPs with lower customer densities.
- Ausgrid (with average customer density) is outperformed on some 'per km' metrics such as total cost compared to other DNSPs with higher customer densities.

PPI techniques are a simpler form of benchmarking that compares inputs to one output. This contrasts with the MTFP, MPFP and econometric opex cost function techniques that relate inputs to multiple outputs.

The PPIs used here support the other benchmarking techniques because they provide a general indication of comparative performance of the DNSPs in delivering a specific output. While PPIs do not take into account the interrelationships between outputs (or the interrelationship between inputs), they are informative when used in conjunction with other benchmarking techniques.

On a 'per customer' metric, large predominantly rural DNSPs will generally perform poorly relative to DNSPs in suburban and metropolitan areas. Typically, the longer and sparser a DNSP’s network, the more assets it must operate and maintain per customer. The 'per MW' metric exhibits a similar pattern. Conversely, on 'per km' metrics, larger, more rural DNSPs will perform better because their costs are spread over a longer network. Where possible, we have plotted PPIs against customer density,[54] to enable readers to visualise and account for these effects when interpreting the results.

We have updated the PPIs in this report to include 2023 data and present them as an average for the five-year 2019–23 period.[55] Importantly, the PPIs in this report have been updated to include the updates set out in section 1.2 related to implementing our approach address capitalisation differences between DNSPs and for the methodological refinements to calculating the AUC of capital.

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54 Customer density is calculated as the total number of customers divided by the route line length of a DNSP.

55 The updated PPIs are in dollar values as at the end of June quarter 2023.

6.1 Total cost PPIs

This section presents total cost PPIs averaged over the 2019–23 period. These compare each DNSP's total costs (opex and asset cost) against a number of outputs in turn.[56] Total cost has the advantage of reflecting the opex and assets for which customers are billed on an annual basis. The three total cost PPIs shown here are:

- Total cost per customer
- Total cost per circuit length kilometre
- Total cost per megawatt (MW) of maximum demand.

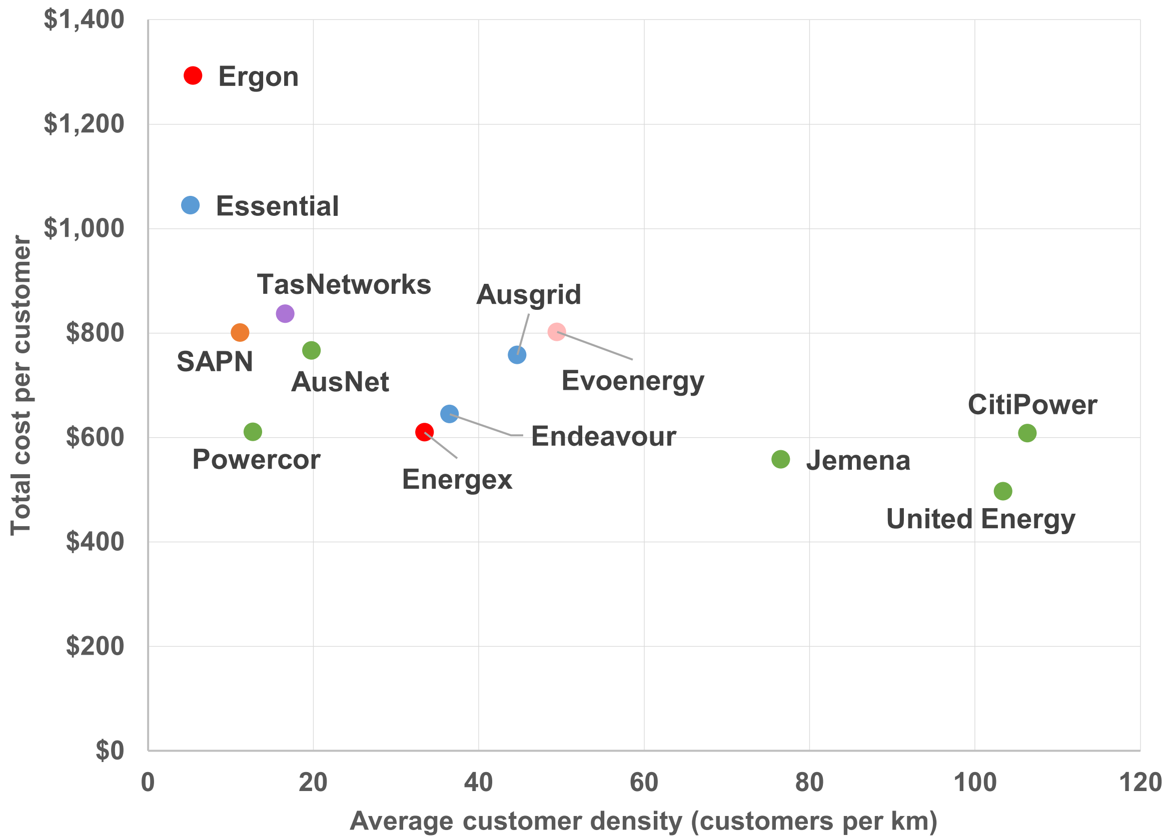
6.1.1 Total cost per customer

Figure 16 shows each DNSP's total cost per customer. Customer numbers are one of the main outputs DNSPs provide. The number of customers connected to the network is one factor that influences demand and the infrastructure required to meet that demand.

Broadly, this metric should favour DNSPs with higher customer density because they are able to spread their costs over a larger customer base. However, it is worth noting that there is a large spread of results across the lower customer density networks. Both Ergon Energy and Essential Energy have a higher total cost per customer compared to other largely rural DNSPs, including SA Power Networks, Powercor, AusNet and TasNetworks. Ausgrid and Evoenergy also have higher costs per customer compared to other networks with similar customer densities and some networks with lower customer densities.

56 We have applied to the PPI calculations the same AUC of capital calculation approach we applied to MTFP and MPFP analysis, incorporating our methodological refinements made in 2024 and described in section 1.2 and Appendix C of this report.

Figure 16 Total cost per customer ($2023) (average 2019–23)

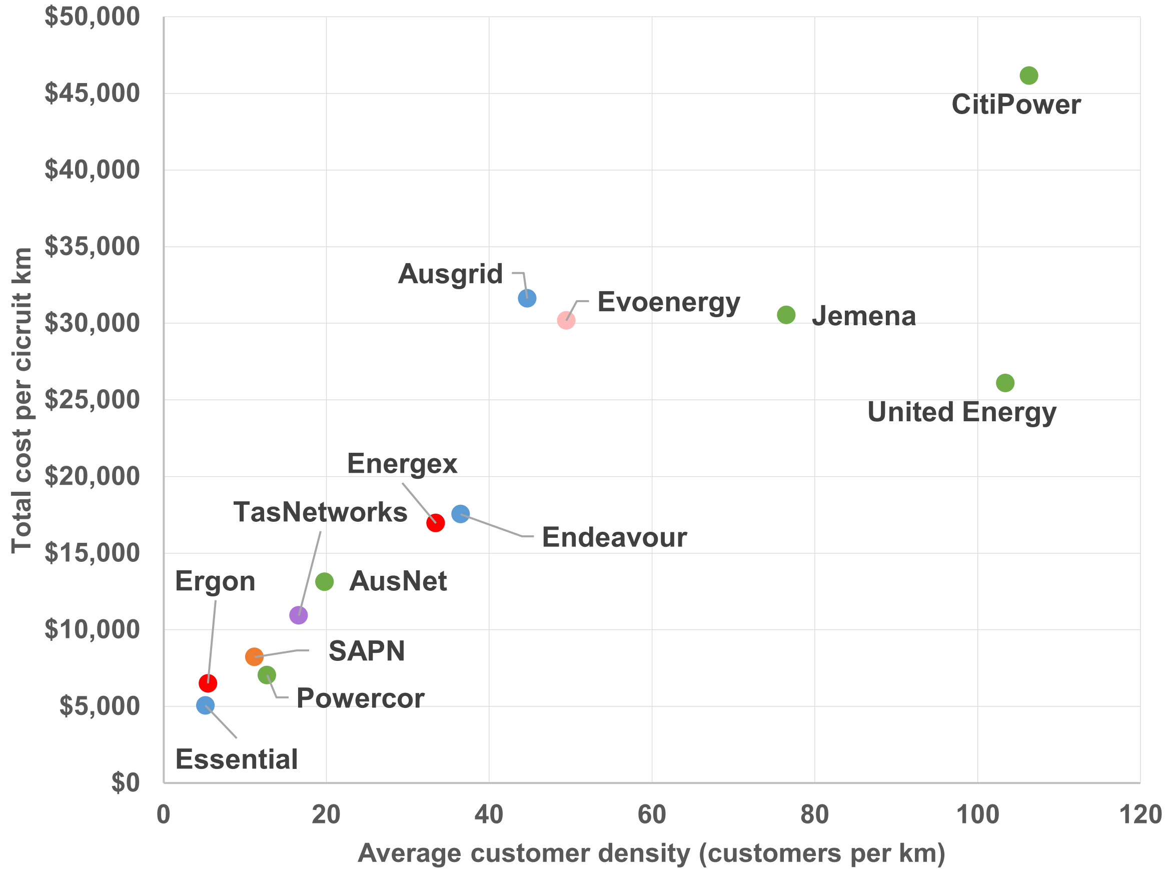


Source: AER analysis; Economic Benchmarking RINs.

6.1.2 Total cost per kilometre of circuit line

Figure 17 presents each DNSP's total cost per km of circuit line length. Circuit line length reflects the distance over which DNSPs must deliver electricity to their customers. CitiPower has the highest total cost per kilometre of circuit line length. As the most customer-dense network in the NEM, this finding must be considered with caution, as 'per km' metrics tend to favour DNSPs with lower customer densities. However, compared to United Energy, which has a similar average customer density, CitiPower performs relatively poorly. Evoenergy and Ausgrid report similar total costs per kilometre of circuit line length to Jemena, despite a much lower customer density.

Figure 17 Total cost per km of circuit line length ($2023) (average 2019–23)

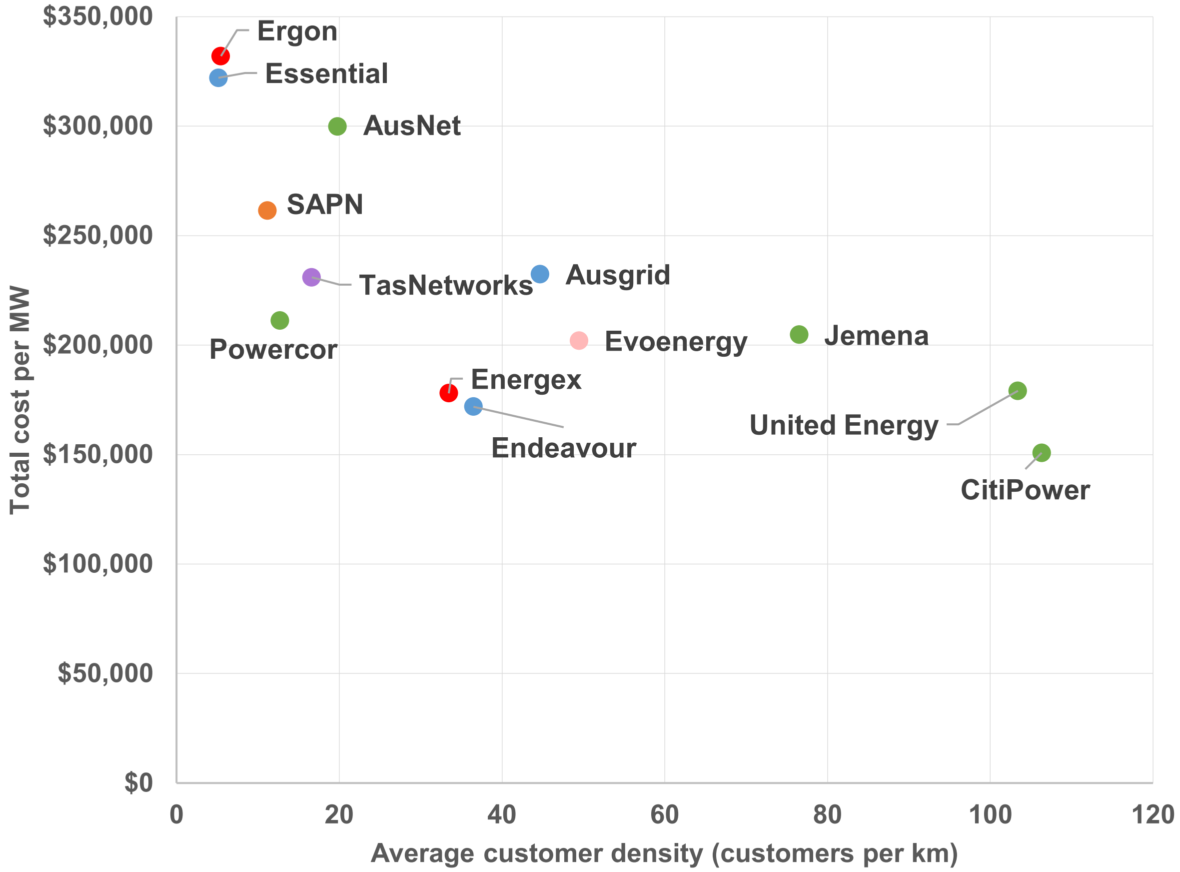


Source: AER analysis; Economic Benchmarking RINs.

6.1.3 Total cost per MW of maximum demand

Figure 18 shows each DNSP's total cost per MW of maximum demand. DNSPs install assets to meet maximum demand. Maximum demand also influences opex, as DNSPs need to operate and maintain assets installed to meet demand at peak time. Similar to total cost per customer, the measure of total cost per MW of maximum demand favours DNSPs with higher customer density. However, the spread of results tends to be narrower than that of the other metrics.

Figure 18 Total cost per MW of maximum demand ($2023) (average 2019–23)



Source: AER analysis; Economic Benchmarking RINs.

6.2 Cost category PPIs

This section presents the opex category level cost PPIs averaged over the 2019–23 period. These compare a DNSP's category level opex (vegetation management, maintenance, emergency response) and total overheads against a relevant output.[57,58]

When used in isolation, these category level PPI results should be interpreted with caution. This is because reporting differences between DNSPs may limit like-for-like category level comparisons. For example, DNSPs may allocate and report opex across categories

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57 We have considered a number of possible output measures such as the length of lines, the energy delivered, the maximum demand and the number of customers served by the service provider. Each of these output measures have advantages and disadvantages. We explain our choice of selected output measure for each of the PPIs below.

58 We have used the category analysis RIN for category level expenditure data, and the economic benchmarking RIN for non-expenditure data (i.e. route line length, number of interruptions etc.). The expenditure data reported in the category analysis RIN reflects the cost allocation methodology, service classification and reporting requirements in place for each DNSP at the time the RIN was submitted.

differently due to different ownership structures and the cost allocation policies it has in place at the time of reporting. There may also be differences in the interpretation and approaches taken by DNSPs in preparing their RIN data.

We use category level PPIs as supporting benchmarking techniques in our revenue determinations, particularly to identify potential areas of DNSP inefficiency in relation to opex.

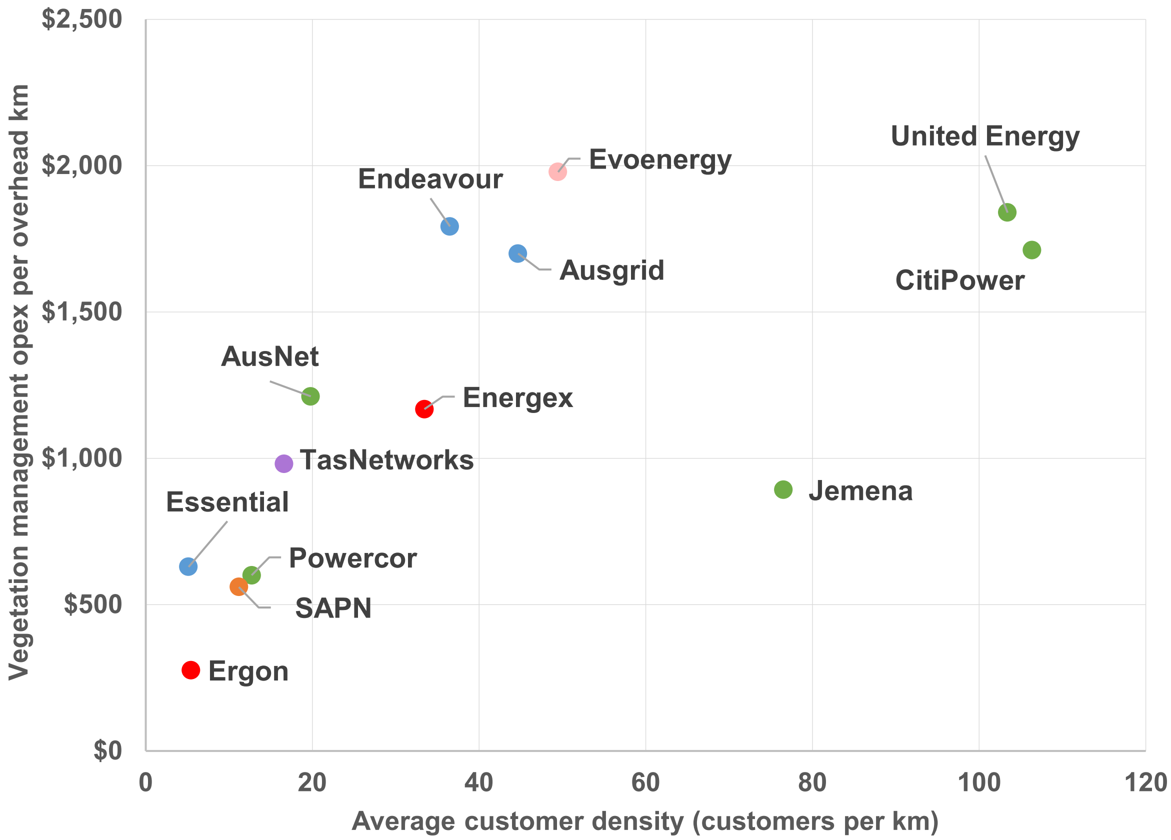
6.2.1 Vegetation management

Vegetation management expenditure includes tree trimming, hazard tree clearance, ground clearance, vegetation corridor clearance, inspection, audit, vegetation contractor liaison, and tree replacement costs. We measure vegetation management per kilometre of overhead circuit line length because overhead line length is the most relevant proxy of vegetation management costs.[59]

Figure 19 shows that Evoenergy, Endeavour Energy, Ausgrid, CitiPower and United Energy have the highest vegetation management expenditure per kilometre of overhead circuit line length relative to other DNSPs in the NEM, including DNSPs with similar customer densities. In contrast, Ergon Energy, SA Power Networks, Powercor and Essential Energy have the lowest vegetation management expenditure per kilometre of overhead circuit line length in the NEM. As ‘per km’ measures tend to favour networks with lower customer densities, the relative performance of these DNSPs is somewhat expected.

[59] Circuit line length contains lengths of lines that are not vegetated. Vegetation maintenance spans is a better indicator; however, we have used overhead route line length instead of vegetation maintenance span length due to DNSPs' estimation assumptions affecting maintenance span length data.

Figure 19 Vegetation management opex per km of overhead circuit length ($2023) (average 2019–23)



Source: AER analysis; Economic Benchmarking RINs.

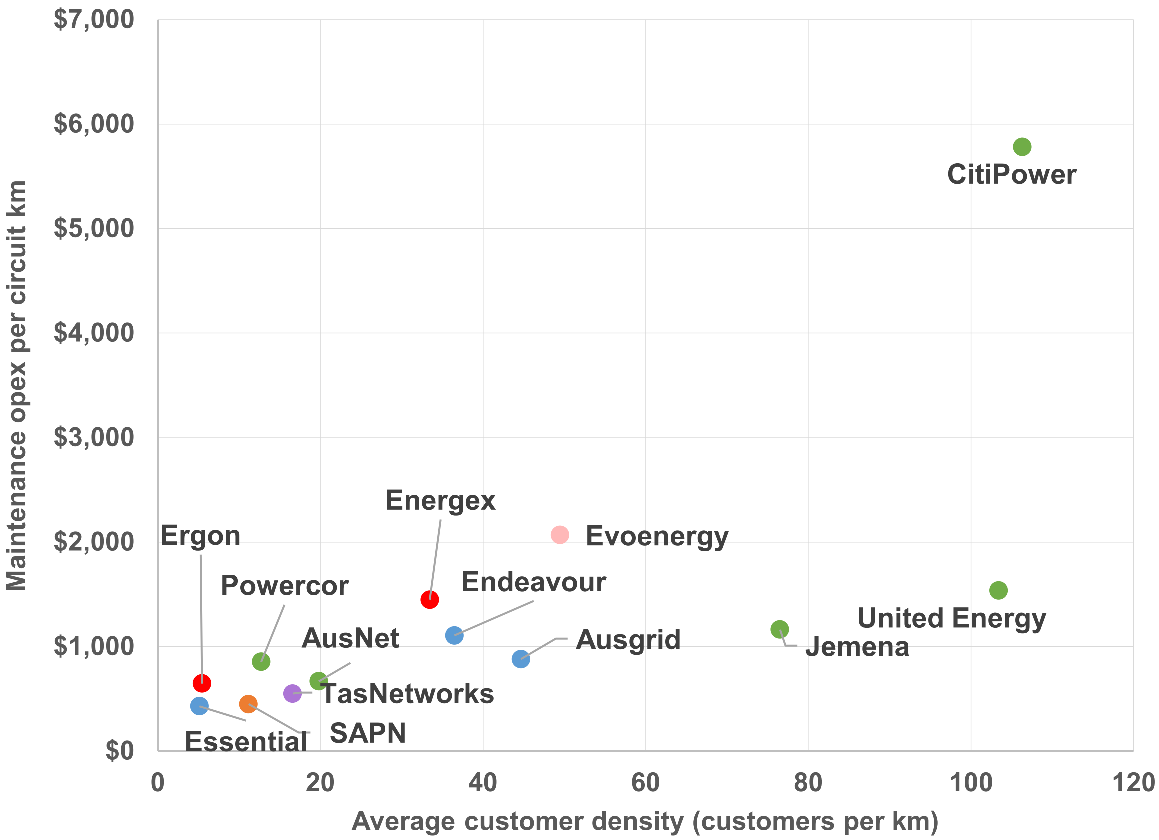
6.2.2 Maintenance

Maintenance expenditure relates to the direct opex incurred in maintaining poles, cables, substations, and protection systems. It excludes vegetation management costs and costs incurred in responding to emergencies. We measure maintenance per circuit kilometre because assets and asset exposure are important drivers of maintenance costs.[60] We use circuit length because it is easily understandable and a more intuitive measure of assets than transformer capacity or circuit capacity.

While CitiPower is one of the best performers in our opex MPFP analysis and econometric benchmarking, Figure 20 shows that it has one of the highest maintenance opex spends per km of circuit length. As a high customer density network, CitiPower is likely to be somewhat disadvantaged through the use of ‘per km’ metrics. However, even compared to other customer-dense networks, CitiPower still performs relatively poorly on this measure.

60 Circuit line length includes both overhead and underground cables.

Figure 20 Maintenance opex per km of circuit length ($2023) (average 2019–23)



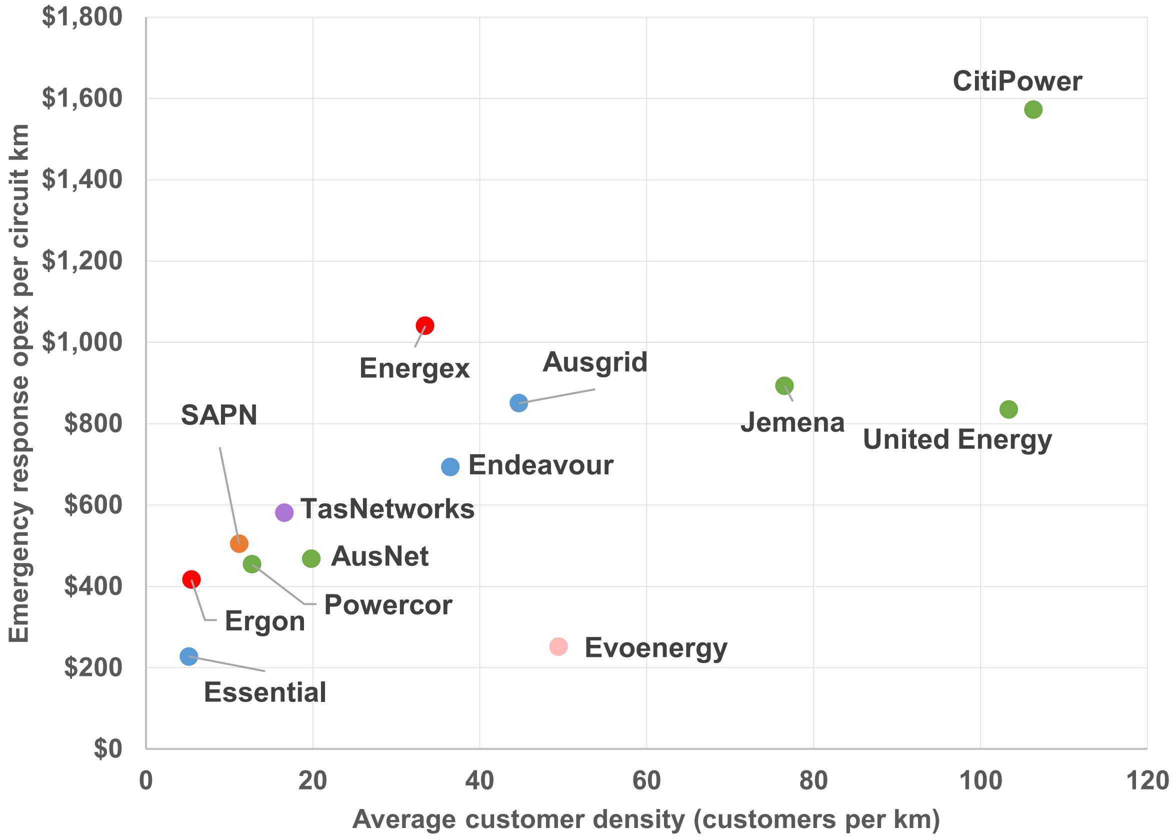
Source: AER analysis; Economic Benchmarking RINs.

6.2.3 Emergency response

Emergency response expenditure is the direct opex incurred in responding to network emergencies. We measure emergency response costs per circuit km because network emergencies primarily affect power lines and poles in the field (e.g. due to storms, fires and road accidents leading to network interruptions and loss of power). Using circuit length also allows for comparisons with maintenance opex per km and vegetation management opex per overhead km. The amount of opex spent on maintenance and vegetation management can influence the instances and severity of emergency responses, and in turn there may be trade-offs between maintenance, vegetation management and emergency response.

Figure 21 shows that CitiPower, United Energy, Jemena, Ausgrid and Energex have higher emergency response cost per km relative to other DNSPs. Similar to its maintenance costs, CitiPower has one of the highest emergency response opex spends per km of circuit length in the NEM. In comparison, Essential Energy and Evoenergy have relatively low emergency response costs per km. There may be higher costs associated with responding to emergencies in more customer-dense networks due to the costs of managing congestion (e.g. closing roads and managing traffic).

Figure 21 Emergency response opex per km of overhead circuit length ($2023) (average 2019–23)



Source: AER analysis; Economic Benchmarking RINs.

6.2.4 Total overheads

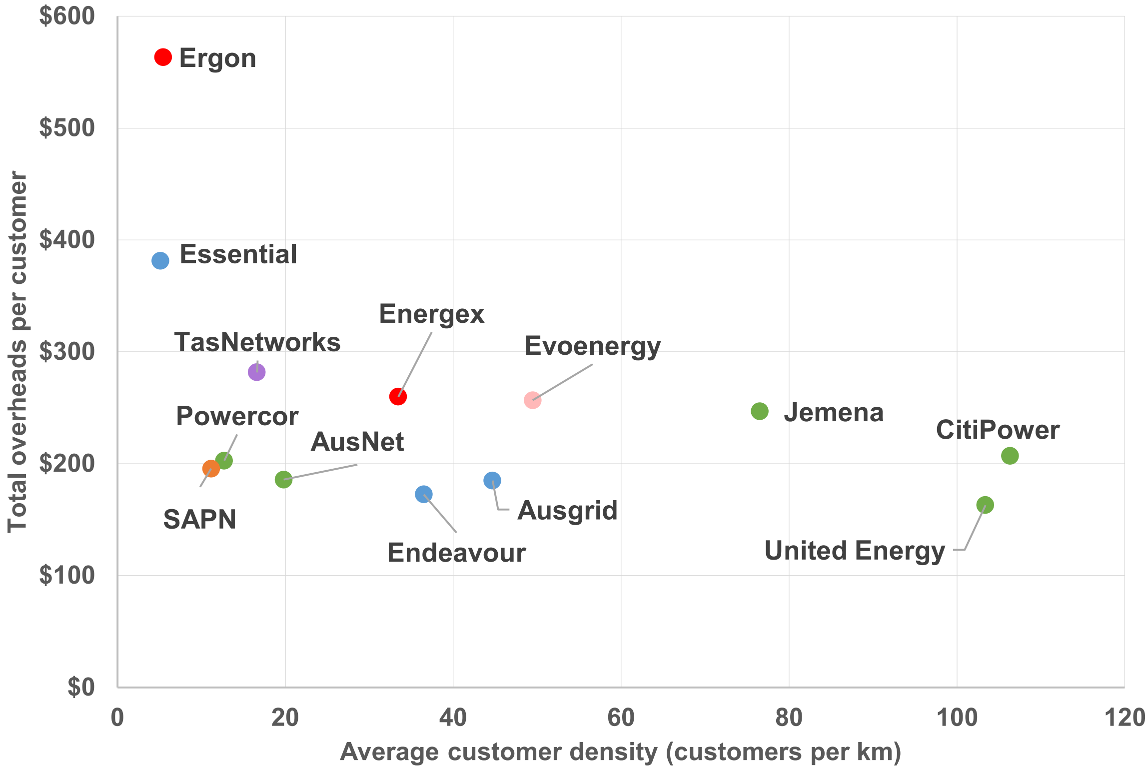
Total overheads (based on total expenditure (totex)) are the sum of corporate and network overheads (opex and capex) allocated to standard control services. We measure total overheads allocated to both capex and opex to ensure that differences in DNSPs' capitalisation policies do not affect the analysis.[61] It also mitigates the impact of a DNSP's choice in allocating their overheads to corporate or network services.

We have examined total overheads by customer numbers because it is likely to influence overhead costs. Figure 22 shows that Ergon Energy has higher overhead costs compared to all other DNSPs, including those DNSPs with similar customer densities. While the 'per customer' measure may favour DNSPs with higher customer density, we do not consider this

[61] By doing this, any differences in capitalisation policy between DNSPs, i.e. whether to expense or capitalise overheads, does not impact the comparison. This is important because there are differences in capitalisation policies between DNSPs and some DNSPs have changed their polices over time. This is part of the reason for implementing our preferred approach to addressing capitalisation differences.

explains Ergon Energy's relative performance. This is because it has significantly higher costs relative to DNSPs of similar customer densities such as Essential Energy.

Figure 22 Total overheads per customer ($2023) (average 2019–23)



Source: AER analysis; Economic Benchmarking RINs.

7 The impact of different operating environments

This section outlines the impact of differences in operating environments not directly included in our benchmarking models. This gives stakeholders more information to interpret the benchmarking results and assess the efficiency of DNSPs. We have also quantified many of the OEFs set out below to include in revenue determinations as a part of our opex efficiency analysis, particularly when using the results from the four econometric opex cost function models. The box at the end of this section provides more details on how we apply OEF adjustments to the econometric benchmarking model efficiency scores.

DNSPs do not all operate under the same operating environments. When undertaking a benchmarking exercise, it is desirable to consider how OEFs can affect the relative expenditures of each service provider when acting efficiently. This ensures we are comparing like-with-like to the greatest extent possible. It also helps us determine the extent to which differences in measured productivity performance are affected by exogenous factors outside the control of each business.

Our economic benchmarking techniques account for differences in operating environments to a significant degree. In particular:

- The benchmarking models (excluding the PPIs) account for differences in customer, energy and demand densities through the combined effect of the customer numbers, network length, energy throughput and ratcheted maximum demand output variables. These are sources of material differences in operating costs between networks.
- The econometric opex cost function models also include a variable for the proportion of power lines that are underground. DNSPs with more underground cables will, all else equal, face lower maintenance, vegetation management and emergency response costs and fewer outages.
- The opex included in the benchmarking is limited to the network service activities of DNSPs. This excludes costs related to metering, connections, street lighting and other negotiated services, which can differ across jurisdictions or are outside the scope of regulation. This helps us compare networks on a similar basis.
- The capital inputs for MTFP and capital MPFP exclude sub-transmission transformer assets that are involved in the first stage of two-stage transformation from high voltage to distribution voltage, for those DNSPs that have two stages of transformation. These are mostly present in NSW, QLD and SA, and removing them better enables like-for-like comparisons.

However, our benchmarking models do not directly account for differences in legislative or regulatory obligations, climate and geography. These may materially affect the operating costs in different jurisdictions and hence may have an impact on our measures of the relative efficiency of each DNSP. As a result, we, and the consultants we engaged to provide us advice on OEFs in 2017, Sapere-Merz, used the following criteria to identify relevant OEFs.[62]

Criteria for identifying relevant OEFs

- **Exogeneity.** Is it outside of the DNSP's control? Where the effect of an OEF is within the control of the DNSP's management, adjusting for that factor may mask inefficient investment or expenditure.
- **Materiality.** Is it material? Where the effect of an OEF is not material, we would generally not provide an adjustment for the factor. Many factors may influence a DNSP's ability to convert inputs into outputs.
- **Non-duplication.** Is it accounted for elsewhere? Where the effect of an OEF is accounted for elsewhere (e.g. within the benchmarking output measures), it should not be separately included as an OEF. To do so would be to double count the effect of the OEF.[63]

Sapere-Merz identified a limited number of OEFs that materially affect the relative opex of each DNSP in the NEM, reflecting its (and our) analysis and consultation with the electricity distribution industry.[64] These are:

- the higher operating costs of maintaining sub-transmission assets
- differences in vegetation management requirements
- jurisdictional taxes and levies
- the costs of planning for, and responding to, cyclones
- backyard reticulation (in the ACT only)
- termite exposure.

Sapere-Merz's analysis and report also provided:

62 We engaged Sapere Research Group and Merz Consulting ('Sapere-Merz') to provide us with advice on material OEFs driving differences in estimated productivity and operating efficiency between DNSPs. See: Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018.

63 For example, our models capture the effect of line length on opex by using circuit length as an output variable. In this context, an OEF adjustment for route length would double count the effect of line length on opex. We also exclude metering services from our economic benchmarking data, meaning an OEF adjustment for the metering services is not needed.

64 The Sapere-Merz report includes more detail about the information and data it used, our consultation with the distribution industry, and the method for identifying and quantifying these OEFs.

- preliminary quantification of the incremental opex of each OEF on each DNSP, or a method for quantifying these costs
- illustration of the effect of each OEF on our measure of the relative efficiency of each DNSP, in percentage terms, using a single year of opex.[65]

A brief overview of the above material factors follows and for network accessibility and workers compensation which assessed as being material in revenue determination processes.

Sub-transmission operating costs (including licence conditions)

Sub-transmission assets relate to the varying amounts of higher voltage assets (such as transformers and cables) DNSPs are responsible for maintaining. The distinction between distribution and sub-transmission assets is primarily due to the differing historical boundaries drawn by state governments when establishing distribution and transmission businesses. In addition, DNSPs in NSW and QLD have historically faced licence conditions that mandated particular levels of redundancy and service standards for network reliability on their sub-transmission assets. DNSPs have little control over these decisions.

Sub-transmission assets cost more to maintain than distribution assets as they are more complex to maintain and higher voltage lines generally require specialised equipment and crews.[66] Our benchmarking techniques do not directly account for these differences. Our circuit line length and ratcheted maximum demand output metrics do not capture the incremental costs to service sub-transmission assets compared to distribution assets. It is necessary to consider this when evaluating the relative efficiency of DNSPs using our benchmarking results.

Sapere-Merz's analysis of sub-transmission costs suggested that some of the NSW and QLD DNSPs require 4 to 6% more opex to maintain their sub-transmission assets, compared to a reference group of efficient DNSPs. Conversely, TasNetworks required 4% less opex because it has far fewer sub-transmission assets.[67]

Vegetation management

DNSPs are required to ensure the integrity and safety of overhead lines by maintaining adequate clearances from vegetation. Vegetation management expenditure accounts for between 10–20% of total opex for most DNSPs and can differ due to factors outside of their control including:

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65 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 35.

66 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 48.

67 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 55.

- Different climates and geography affect vegetation density and growth rates, which may affect vegetation management costs per overhead line kilometre and the duration of time until subsequent vegetation management is again required.
- State governments, through enacting statutes, decide whether to impose bushfire safety regulations on DNSPs.
- State governments also make laws on how to divide responsibility for vegetation management between DNSPs and other parties.

Sapere-Merz found that variations in vegetation density and growth rates, along with variations in regulation around vegetation management, are likely to be a material and exogenous driver of variations in efficient vegetation management opex. However, under its suggested methods, it could not quantify this OEF based on available data.[68] Sapere-Merz observed that while total vegetation management opex is collected, data about the spans impacted and the density of vegetation needs refinement and consultation with DNSPs to ensure consistency. Sapere-Merz noted that if reliable and consistent data was available, an OEF could be estimated. It also proposed refinements in relation to regulatory (bushfire regulation and division of responsibility) data.[69]

Recognising this as an area for improvement, in 2020 we undertook some analysis into the quantity and quality of data related to vegetation management. Our main focus was assessment of network characteristic data in the RINs relating to spans, including the total number of vegetation management spans, with a view to calculating an OEF.[70] However, we were not able to develop any clear conclusions from this analysis due to concerns regarding the comparability and consistency of some of the data. For example:

- some inconsistency in DNSPs' definitions of active vegetation management span
- differences in contractual arrangements and vegetation management cycles.

While not able to use Sapere-Merz's suggested methodology, we have undertaken further work to quantify the impacts of any differences arising due to vegetation management in our revenue determinations for NSW, ACT, Queensland and Victorian DNSPs.[71] These decisions used consistent methods and involved the summation of two exogenous factors:

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68 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, pp. 65–66.

69 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, pp. 67–68.

70 A span refers to the distance between two poles. If a DNSP records poles rather than spans, the number of spans can be calculated as the number of poles less one. Total vegetation management spans refer to the number of spans in a DNSP's network that are subject to active vegetation management practices (i.e. not merely inspection) in the relevant year.

71 AER, *Draft Decision Evoenergy, Regulatory proposal 2024 to 2029, Attachment 6 Operating Expenditure*, September 2023, pp. 28-31; AER, *Final decision Ergon Energy distribution determination 2020−25 Attachment 6 - Operating expenditure*, June 2020, p. 25; AER, *Draft decision Energex distribution determination 2020−25 Attachment 6 - Operating expenditure*, June 2020, pp. 57–79; AER, *Final decision*

- differences in vegetation management obligations relating to managing bushfire risk
- differences in the division of responsibility for vegetation clearance with local councils, road authorities and landowners.

We have quantified the differences in the costs related to bushfire obligations by examining the increase in costs faced by Victorian DNSPs following the 2009 Black Saturday bushfires. These reflect an incremental difference in bushfire risk and responsibilities between the Victorian and non-Victorian DNSPs. This quantification was based on forecast costs of step changes and opex pass throughs for the Victorian DNSPs that we approved for the 2011–15 period. The increased opex incurred as a result of these new regulations is used as a proxy for the differences in costs of managing bushfire risks in Victoria compared to other states. We updated the cost estimates for the relevant benchmark periods and new comparator benchmark DNSPs.

We have calculated a division of responsibility OEF for non-Victorian and South Australian DNSPs[72] to reflect the cost disadvantage these DNSPs face in the scale of vegetation management responsibility compared to the benchmark comparator firms in these states. For example, in Queensland DNSPs are responsible for vegetation clearance from all network assets, whereas other parties such as councils, landowners and roads authorities are responsible for some vegetation clearance in Victoria and South Australia. We derived the OEF adjustment by calculating:

- how much of the vegetated lines in Victoria and South Australia were managed by parties other than the DNSPs (e.g. local councils) in those states
- then multiplying the proportion of opex that relates to vegetation management by the proportionate increase in responsibility the non-Victorian and South Australian DNSPs face relative to the Victorian and South Australian DNSPs.

In light of the further work we have done to improve the models setting out the OEF adjustments, and how these are used in our base opex efficiency analysis (noted in section 5), we have received feedback from several DNSPs in relation to the above approach to calculating the vegetation management OEF. Several DNSPs have previously raised concerns about the above method and did not consider it appropriate to apply to this

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Jemena distribution determination 2021−26 Attachment 6 - Operating expenditure, April 2021, pp. 29–30; AER, *Final decision AusNet Services distribution determination 2021−26 Attachment 6 - Operating expenditure*, April 2021, pp. 28–29.

72 This OEF adjustment is by definition zero for any Victorian or South Australian DNSP since the cost disadvantage is calculated by comparison to the division of responsibility applying in Victoria or South Australia.

approach to the benchmarking results without further refinement.[73] Evoenergy noted that the vegetation management OEF as currently calculated does not reflect the risk of bushfires and impact on vegetation management costs, but rather the impact of bushfire-related regulations imposed on Victorian networks in 2011. Further, that there have been changes to Evoenergy's vegetation management obligations in 2011 that were not currently taken into account. Essential Energy also noted new legislative bushfire obligations in NSW that should be taken into account.[74] AusNet and CitiPower, Powercor and United Energy did not consider the division of responsibility for vegetation clearance to be a material factor. Jemena recommended that the AER update one of the key numbers used in the calculation of the division of responsibility factor.

As noted in section 8.1, we will seek to improve the data and quantification of the vegetation management OEF as is possible, including in the context of revenue determination processes. In this regard, we assessed changes in Evoenergy's vegetation management obligations as part of its 2024–29 revenue determination which led to an updated OEF adjustment.[75]

Cyclones

Cyclones require a significant operational response including planning, mobilisation, fault rectification and demobilisation. DNSPs in tropical cyclonic regions may also have higher insurance premiums and/or higher non-claimable limits. Ergon Energy is the only DNSP that we benchmark that regularly faces cyclones. Sapere-Merz estimated that Ergon Energy required up to 5% more opex than other DNSPs to account for the costs of cyclones.[76]

Taxes and levies

A number of jurisdictions require the payment by DNSPs of state taxes and levies such as licence fees and electrical safety levies. As they are state-based, any such taxes or levies could vary between jurisdictions and hence DNSPs. These are outside the control of DNSPs.

Sapere-Merz provided a preliminary quantification of the impact of taxes and levies on each DNSP.[77] This was based on information provided by each DNSP in its RINs and in response

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73 Evoenergy, *Email to AER – Refined benchmarking roll-forward model and OEF spreadsheets*, received on 19 August 2022; Essential Energy, *Email to AER – Refined benchmarking roll-forward model and OEF spreadsheets*, received on 21 August 2022; AusNet, *Email to AER – AER 2022 Annual Benchmarking Report for distribution - preliminary benchmarking results*, received on 30 August 2022; CitiPower, Powercor and United Energy, *Email to AER – AER 2022 Annual Benchmarking Report for distribution - preliminary benchmarking results*, received on 26 August 2022.

74 Essential Energy, *Email to AER – AER 2024 Annual Benchmarking Report – Distribution network service providers – Consultation stage 1,* 22 August 2024.

75 AER, *Draft Decision Evoenergy, Regulatory proposal 2024 to 2029*, September 2023, pp. 28–31.

76 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 77.

77 Our standard approach for the taxes and levies OEF data set, as applied in the Energex and Ergon Energy 2025–30 revenue determinations, has been to include only the taxes and levies that are energy-industry specific. We made an exception for the Evoenergy final determination, where we did not apply this OEF, on

to information requests. The impact of differences in taxes and levies generally do not have a significant impact on the relative costs of DNSPs (i.e. beyond 1%). However, Sapere-Merz estimated that TasNetworks requires 5% more opex than other DNSPs due to significant costs imposed by the Tasmanian Electrical Safety Inspection Levy.[78] We recently made minor updates to the data used in the calculation of this OEF.[79]

Backyard reticulation in the ACT

Historical planning practices in the ACT mean that in some areas overhead distribution lines run along a corridor through backyards rather than the street frontage as is the practice for other DNSPs. Although landowners are theoretically responsible for vegetation management along the majority of these corridors, Evoenergy has a responsibility to ensure public safety, which includes inspecting backyard lines and issuing notices when vegetation trimming is required. On the basis of information provided by Evoenergy, Sapere-Merz estimated that Evoenergy requires 1.6% more opex than other DNSPs in the NEM to manage backyard power lines in the ACT.[80]

In its recent revenue determination process, Evoenergy proposed updated cost estimates for the activities related to inspecting and maintaining backyard lines.[81] We assessed these to be reasonable and as a result determined that an updated OEF of 3.5% was appropriate to reflect the additional opex Evoenergy requires to manage backyard power lines in the ACT.

Termite exposure

DNSPs incur opex when carrying out termite prevention, monitoring, detection and responding to termite damage to assets. These costs depend on the number of a DNSP’s assets (particularly wooden poles) that are susceptible to termite damage and the prevalence of termites within the regions where the DNSP’s assets are located. Termite exposure is the smallest of the material OEFs identified by Sapere-Merz. Its preliminary analysis suggested that termite exposure primarily affects Ergon Energy and Essential Energy, where they

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the basis of evidence that Evoenergy may be disadvantaged by the exclusion of payroll and land taxes from the calculation. See: AER, *Final Decision Evoenergy, Regulatory proposal 2024 to 2029, Attachment 6 Operating Expenditure, April 2024*, pp. 22–23.

78 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 72.

79 This related to inclusion of regulatory fees paid by AusNet, which had previously been omitted.

80 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 80.

81 AER, *Draft Decision Evoenergy, Regulatory proposal 2024 to 2029*, Attachment 6 Operating Expenditure, September 2023, pp. 31-32.

require 1% more opex to manage termites.[82] Ausgrid identified a data error in the number of wooden poles it owns that were used in previous calculations of this OEF. We have identified the source of the original data and the revised data is now being applied in the calculation of this OEF.

Network accessibility

Some DNSPs may incur higher cost of network access to undertake route maintenance (e.g. due to adverse climate and heavy rainfall). In its final report, Sapere-Merz noted that a network accessibility OEF for Power and Water in the Northern Territory would require further data and analysis to determine if it met the OEF criteria.[83]

In our recent revenue determination for Ergon Energy, we included a network accessibility OEF.[84] We had included this OEF in our previous (2015, 2020) Ergon Energy revenue determinations, and considered that the network accessibility circumstances it faced have likely not changed since our 2015 assessment.[85] We relied on our 2015 assessment approach, with updated data on network without standard vehicle access up to 2022. Where this OEF is relevant and data is satisfactory, we intend to apply this approach.

Workers' compensation

Workers' compensation is a form of insurance payment to employees if they are injured at work or become sick due to their work. It can include payments to employees to cover their wages while they are not fit for work as well as medical expenses and rehabilitation. Workers' compensation is governed by individual Australian states and territories and employers in each state or territory have to take out workers' compensation insurance to cover themselves and their employees.[86]

Our recent revenue determination for Evoenergy included a workers' compensation OEF accounting for the differences in the relative cost of workers' compensation between jurisdictions.[87] In support of this new OEF, Evoenergy cited Marsh data which suggested that workers' compensation premium rates for the electricity industry in the ACT were 2.7 times greater than any other state, measured as an average percentage of payroll.[88] We accepted

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82 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 74.

83 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 31.

84 AER, *Ergon Energy distribution revenue proposal 2025−30 Attachment 6 - Operating expenditure*, September 2024, pp. 23–24.

85 AER, *Preliminary decision Ergon Energy distribution determination 2015−20 Attachment 7 - Operating expenditure*, April 2015, p. 248; AER, *Final decision Ergon Energy distribution determination 2015−20 Attachment 7 - Operating expenditure*, October 2015, p. 53.

86 See: https://www.fairwork.gov.au/employment-conditions/workers-compensation.

87 AER, *Final Decision Evoenergy, Regulatory proposal 2024 to 2029, Attachment 6 Operating Expenditure, April 2024*, pp. 20–21.

88 Evoenergy, *Marsh – ActewAGL Distribution ACT Workers Compensation, Appendix 2.2*, January 2023.

that Evoenergy faced a material cost disadvantage relative to the comparator DNSPs as a result of higher workers' compensation insurance premiums in the ACT. In our final revenue determination, we assessed an OEF adjustment for Evoenergy of 0.7% was appropriate to reflect these additional costs.[89]

How we apply OEF adjustments to the benchmarking scores

As discussed at the end of section 5 in relation to the econometric opex cost function models, we use a 0.75 benchmark comparator point to assess the relative operating efficiency of DNSPs (the best possible efficiency score is 1.0.) We adjust the benchmark comparison point for opex for the impact of material differences in the OEFs between the business and the benchmark comparators that are not already captured in the modelling. The benchmark comparators are those DNSPs that have an econometric model-average efficiency score above the 0.75 benchmark comparison score.

To calculate the adjustment for an OEF for a particular DNSP, the incremental opex of that factor as a percentage of (efficient) opex is compared with the customer-weighted average for the comparator DNSPs. Where this difference is positive (negative), indicating a relative cost disadvantage (advantage) for that DNSP, this results in a positive (negative) OEF adjustment. We apply the OEF adjustment by adjusting the 0.75 benchmark comparison point (upwards for negative OEFs, downwards for positive OEFs). This adjusted comparison point is then compared to the business's efficiency score (from the benchmarking models), allowing us to account for potential cost differences due to material OEFs between the business and the benchmark comparators.

The application of OEF adjustments as described above is illustrated with the following hypothetical example of a DNSP with a 'raw' opex efficiency score of 0.50 and which faces an exogenous condition unique to its operating environment and its associated costs. As shown below, the 0.75 comparator point is as a result adjusted downwards to 0.68.

Hypothetical example:

A	Raw benchmarking efficiency score	0.5
B	Efficient total opex ($ million)	100
C	Opex due to unique operating environment factor ($ million)	10
D	OEF as a percentage of total opex (C/B)	10/100 = 0.10
E	Adjusted 0.75 comparator point (0.75/(1+D))	0.75/(1+0.10) = 0.68
F	Efficiency adjustment to period average opex (1-(A/E))	(1-0.5/0.68) = 27%

89 AER, *Final Decision Evoenergy, Regulatory proposal 2024 to 2029, Attachment 6 Operating Expenditure, April 2024*, p. 21.

We do not expect to be able to quantify and apply OEF adjustments for all operating environment differences between DNSPs; however, we consider that the OEFs we do apply as listed above, capture the most material differences in addition to those already captured in the modelling. More detail on the mechanics of our approach is contained in past decisions and our work in 2022 to improve the models setting out the OEF adjustments.[90]

[90] AER, *Preliminary decision, Ergon Energy determination 2015–20, Attachment 7 – Operating expenditure*, April 2015, pp. 93–138; AER, *Draft decision, Ausgrid distribution determination 2019–24, Attachment 6 – Operating expenditure*, November 2018, pp. 31–33; AER, *Draft decision, Endeavour Energy distribution determination 2019–24, Attachment 6 – Operating expenditure*, November 2018, pp. 27–29; AER, *Draft Decision Evoenergy, Regulatory proposal 2024 to 2029, Attachment 6 Operating Expenditure*, September 2023; AER, *Final Decision Evoenergy, Regulatory proposal 2024 to 2029, Attachment 6 Operating Expenditure,* April 2024, pp. 9–40; AER, *Ergon Energy distribution revenue proposal 2025−30 Attachment 6 - Operating expenditure*, September 2024, pp. 11–30.

8 Benchmarking development

We operate an ongoing program to review and incrementally refine elements of the benchmarking methodology and data. The aim of this work is to maintain and continually improve the reliability and applicability of the benchmarking results we publish and use in our network revenue determinations. This includes where necessary considering if, and how, the changing environment DNSPs operate in (the broader economy and within the context of the energy transition) impacts the benchmarking methodology and data.

There are a variety of factors, and associated costs and benefits, informing the development work we prioritise and progress, including:

- Feedback from stakeholders, which can often contain a range of views
- The materiality and impact of the development work and potential for errors on the robustness of the benchmarking
- The materiality and impact of the development work in relation to upcoming revenue determinations in which the benchmarking results will be used
- The ability to progress this work, including any sequencing issues and data availability
- The resources available to undertake this work.

With this development work often being complex, we exercise judgement in coming to a realistic view on relative priorities. We value the stakeholder feedback provided in relation to development issues, which contributes to our thinking and ongoing improvement in the benchmarking, even in instances where we do not necessarily agree with points raised or adopt specific suggestions.

Table 3 sets out the benchmarking development priorities for distribution that we have progressed this year, that we propose, at this stage, to progress in future years and those issues we intend to progress incrementally. The key benchmarking development priorities we have, and plan to, progress are then discussed in the following sections.

Table 3 Benchmarking development priorities for distribution and timing

Development issue	Timing
Independent review of non-reliability output weights	2024 – completed
Finalising the approach to addressing capitalisation differences	2024 – completed
Improving the performance of the econometric opex cost function models	2024 and 2025 – in progress
Benchmark comparison point used in applying the econometric opex cost function models	From 2025-26
Further review of export service impacts on benchmarking	By 2027
Incremental issues including: • Improving the quantification of OEFs (existing and new)	As resourcing permits

Development issue	Timing
• Examining the weight allocated to the reliability output • Various data and measurement issues • If and how emissions reduction may impact the benchmarking • If and how Power and Water can be incorporated into benchmarking	

8.1 Independent review of the non-reliability output weights

Background

In the 2020 Annual Benchmarking Reports we corrected an error identified in the non-reliability output weights used in our TFP and MTFP models. We also committed to have these output weights independently reviewed in the future.[91] This year we engaged the University of Queensland's CEPA to undertake this review. Specifically, the review was to consider whether there were any further errors in the way these weights are currently calculated, the advantages and disadvantages of the approach we currently used to estimate these weights (econometric modelling of the Leontief cost function (Leontief method)) and whether there were any other options to estimating these weights.

Key findings

CEPA's review based on its final report found that:[92]

- There are no errors in the way in which the AER computes these output weights using the Leontief method, for both transmission and distribution.
- The Leontief method is likely to be suitably robust and flexible enough for its purpose. Further, there may not be a better method for deriving these output weights, other than moving away from an index number-based approach.
- Under the Leontief method, there are two potential concerns around the numerical stability of the non-linear least square estimation method used, namely:
    (1) the potential that the estimation method may not be obtaining a global optimum
    (2) the possibility that there may be multiple alternative values in terms of the underlying parameter estimates that could support an optimal solution.
- If these potential concerns are found to exist, there are some minor practical modifications that could be made to the Leontief method:

91 AER, *2020 distribution network service provider benchmarking report*, November 2020

92 CEPA, *Final report - Review of AER's estimated non-reliability output weights used in the TFP and MTFP benchmarking models*, November 2024, pp.12-17.

(1) linearising the time trend in the Leontief method to guarantee that a global optimum is always obtained
(2) using quadratic programming to estimate the Leontief model and the minimisation of mean absolute deviations approach (or least absolute deviations), to help mitigate some of the risk of there being multiple solutions (noting that this latter risk may not be entirely eliminated under the current TFP/MTFP framework).

- While outside the scope of this review, 'direct-cost benchmarking' (such as data envelopment analysis) was suggested as an alternative approach to measuring productivity without constructing output weights.

Consultation

We invited submissions on CEPA's draft report from relevant stakeholders. We received 3 submissions from Ausgrid, Evoenergy and Jemena.[93]

All submissions endorsed the review and raised no issues with CEPA's findings that there were no errors in the way in which the AER computes these weights. Submissions advocated for the AER to update these weights to incorporate all available years of data, noting that these weights were last updated in 2020.

In their submissions, Ausgrid and Evoenergy both:

- Did not support the AER incorporating CEPA's proposed modifications to the Leontief method, as they considered the potential concerns CEPA raised were not likely common in practice and the modifications would only serve to convolute the AER's existing Leontief method. CEPA considered these arguments in its final report but maintained that its suggested modifications would still have utility.
- Raised two further potential issues in relation to the Leontief method it considered CEPA had not covered:
  (1) Multicollinearity: where some of the explanatory variables in the Leontief method are correlated with one another. CEPA considered that the effects of any potential multicollinearity on the computation of these output weights was unclear, and that AER's current approach aligned with generally accepted standard econometric practice.
  (2) Non-linear changes in opex over time: where the Leontief method may not account for non-linear movements in opex over time. CEPA considered that the only practical way to address this issue would be for the AER to consider CEPA's suggestion of a direct cost benchmarking approach (which Ausgrid and Evoenergy were against).
- Did not support CEPA's suggestion of direct cost benchmarking as they preferred the current TFP/MTFP framework for making productivity comparisons over time and against their peers. CEPA acknowledged this aspect was out of scope for its review but

93 Ausgrid, *Submission to CEPA draft report*, September 2024; Evoenergy, *Submission to CEPA draft report*, September 2024; Jemena, *Submission to CEPA draft report*, September 2024.

considered that such an approach would allow for a similar analysis to the AER's current approach using the PIN technique.

Evoenergy's submission also endorsed CEPA's suggestion of using quadratic programming to estimate the AER's Leontief function, and suggested that this could be done without linearising the time trend as assumed by CEPA. CEPA agreed with this alternative.

Jemena's submission also advocated for adding a fixed cost component to the Leontief method. CEPA considered that this point by Jemena would be addressed by CEPA's suggestion to linearise the time trend, which would add an intercept to the current approach.

Next steps

Based on CEPA's review, and the submissions we received, we will explore the potential concerns CEPA raised with the Leontief method and the validity of its proposed modifications. We will do this for the 2025 Annual Benchmarking Report. We also agree with stakeholders that the output weights should be updated to include all available years of data and will do this for the 2025 Annual Benchmarking Report.

8.2 Finalising the implementation of our approach to addressing capitalisation differences

This year we also finalised implementing the method to address capitalisation differences.

Following consultation, as set out in sections 1.2 and 1.3, in this report we only present the benchmarking results using our preferred method to address differences in capitalisation between DNSPs. As per our final guidance note, this means we use DNSPs' opex under their 2022 CAMs and include 100% of corporate overheads as opex for benchmarking purposes.[94] This is a change from the 2023 Annual Benchmarking Report where we reported the results with and without this change.

In implementing this approach, as CCOs are treated as opex for DNSP benchmarking purposes, we need to ensure they are not double counted as a component of opex and capex, the latter of which is reflected in the AUC of capital. Given this we adjust the AUC of capital to remove CCOs from capex. When we consulted DNSPs, they broadly supported the continued use of the approach first implemented in the 2023 Annual Benchmarking Report. We have implemented this with only a minor refinement relating to the CAM basis of the CCOs removed from the RAB in adjusting the AUC. Specifically, we use reported CCOs in each year, reflecting the prevailing CAM at the time. In our implementation for the 2023 Annual Benchmarking Report we used CCOs based on a fixed 2022 CAM. This slight change recognises that capex data used in the AUC calculation reflects the CAM at that time of reporting, in contrast with opex data used in benchmarking which has historically been reported on a fixed CAM basis. It also ensures consistency with the CCOs that would have

94 AER, *How the AER will assess the impact of capitalisation differences on our benchmarking – Final Guidance Note*, May 2023.

been embedded in each year's capex, and added to the RAB. In the context of the CCOs that are added to opex for benchmarking purposes, these are based on the 2022 CAMs, consistent with the updated basis for opex.

8.3 Consideration of possible options to improve the performance of the Translog models

As set out in section 5, the prevalence of monotonicity violations in the Translog econometric cost function models has increased in this year's results. This continues a trend of worsening monotonicity performance beginning in 2019. The Translog model is, by design, more flexible than the Cobb-Douglas model through the addition of 'second-order' terms in the output specification.[95] The downside of this flexibility is that monotonicity is not necessarily satisfied for all observations in the data sample, which is what we are seeing again in this year's results. In addition, the issue of non-convergence in the short period Stochastic Frontier Analysis Translog model arose in this year's report, as also explained in section 5.

As outlined in section 1.4.4, DNSPs have continued to raise concerns around these issues. Some DNSPs called for a program of work to be developed to address the performance issues.

Investigating and improving, where possible, the performance and reliability of the Translog econometric opex cost function models, particularly in relation to satisfying monotonicity, is important and ongoing development work. We consider the monotonicity violations, coupled with model non-convergence, are complex issues and are unlikely to be attributed to one cause. Instead, they are likely driven by a variety of factors such as multicollinearity, potential misspecification issues and data sample issues. We, in consultation with our consultant Quantonomics, reviewed these causes and drivers and potential approaches to address them. Table 4 summarises at a high level the results of this review.

Table 4 Potential causes, drivers and approaches to address monotonicity and non-convergence

Cause	Driver	Potential approaches
Multicollinearity	Higher order output variables potentially being correlated	Hybrid models Output index
Misspecification of the model	The time trend not allowing for varying efficiency over time The error term structure	Jurisdiction specific time trends Time varying time trend

95 In econometric models, first-order terms have a linear relationship to the dependent variable, and second-order terms have a quadratic relationship to the dependent variable. In addition to the Cobb Douglas model's first-order terms, the Translog model also includes quadratic and interaction terms in the outputs.

Cause	Driver	Potential approaches
	The functional form The possibility of omitted variables and wrongly included variables	Half-normal error term Hybrid models CES models Direct modelling of OEFs Weather term for Ontario
Data sample issues	Inadequate variation in the sample The potential impact of influential observations Data issues	Adding more data points Consideration of the ratcheted maximum demand output Weighting of Australian DNSPs Robust regression Revised circuit line length for Ontario
Definition	Monotonicity definition	Consideration of statistically significant monotonicity

We prioritised further consideration of these potential approaches in terms of their likelihood of success, feasibility / practicability, consistency with economic / econometric theory and consistency with AER approaches / not creating inconsistency or precedent issues. This was done taking into account work previously undertaken, including by Quantonomics.[96]

As a result of this exercise, we identified the following approaches with the potential to address both monotonicity and non-convergence as priority areas to explore. These focus on the potential misspecification issues related to the time trend and the assumption in the current models of inefficiency not varying over time:

- Jurisdiction specific time trends — explore whether including separate time trends for each jurisdiction (Australia, New Zealand and Ontario) improves model performance.
- Time varying inefficiency — explore whether and how to modify the models to differentiate between the effects of technical change (“frontier shift”) and changes in cost efficiency (“catch-up”), both changing over time. This work recognises that the base models assume that inefficiency is unchanging over the sample period, and that, in actuality, DNSPs’ inefficiency will likely change over a lengthy period. As noted in section 1.4.4, some DNSPs considered the base models’ lack of time varying

96 Quantonomics, *Opex Cost Function-Options to Address Performance Issues with Translog models*, October 2023; Quantonomics, *Opex Cost Function Development*, October 2022.

inefficiency to be a source of model misspecification, which, in turn, is driving monotonicity issues and the more recent issue of non-convergence.

- Addressing circuit length inconsistencies in Ontario — explore whether addressing observed inconsistency in the way in which circuit length is defined in the Ontario sub-sample improves the model performance.
- Depending on the results under each approach in isolation, to examine combinations of approaches.

As context for this work, the time trend is included in the current models to capture technical change that occurs over time. In practice, it also captures any factor that impacts opex over time that is not already accounted for in the model, such as changing regulatory obligations. There is also currently a single time trend term across the 3 jurisdictions, and it changes opex at a constant percentage rate each year.

In the case of technical change, it may be reasonable to assume that the electricity distribution industry shares broadly the same technology across jurisdictions, and this common technology changes at a constant rate over time. However, in relation to the other factors not modelled that change over time, it is plausible these are somewhat different across the 3 jurisdictions. In addition, these factors may not change at a constant rate over time. By introducing jurisdiction-specific time trends, the rationale for the phase 1 work is to better capture systematic differences between these 3 jurisdictions in factors affecting opex that vary over time (apart from output growth and the share of undergrounding, which are directly estimated).

For practicability purposes, including given the relatively complex nature of these issues and the empirical and iterative nature of this work, we have divided this work into two phases:

- Phase 1 explores the jurisdiction specific time trends and circuit length inconsistencies in Ontario.
- Depending on the results of phase 1, phase 2 will then explore alternative time trend specifications, particularly those that incorporate inefficiency varying over time.

The phase 1 work is initiated in the form of a memorandum prepared by Quantonomics being released with this 2024 Annual Benchmarking Report. We are seeking submissions and comments from stakeholders by 28 February 2025.

This memorandum explores different time trends for the 3 jurisdictions, while retaining linearity in the rate. The results indicate a broad directional improvement in performance over the current models, as indicated by monotonicity outcomes and other measures such as goodness of fit. The SFATLG model also reached convergence. However, despite these improvements the results are somewhat mixed and not ambiguously an improvement. For example, we continue to see monotonicity violations, in both the Australian and overseas DNSPs, and there are some anomalous parameter estimates.[97]

With the benefit of this work, and submissions, we intend to undertake the phase 2 work over the first half of 2025. As outlined above, this phase will focus primarily on whether and how to incorporate time varying inefficiency into the models. To provide an outlook for what this work entails, Quantonomics' memorandum provides initial thoughts around possible alternative methods, issues and challenges in addressing time varying inefficiency. Feedback in submissions from stakeholders is also welcome on these aspects.

When the phase 2 work is complete this will inform any changes to the econometric opex cost function models we make in the 2025 Annual Benchmarking Report and any application of these results in revenue determinations. Consistent with our approach to date, which we consider fit for purpose, while this development work is ongoing we will not apply the Translog model efficiency results when there are monotonicity violations and non-convergence issues. We consider it appropriate to not use the results of models that do not produce valid, economically principled, results. However, where they do produce valid results we consider it is appropriate to include them in the reported average efficiency scores.

In relation to non-convergence, as outlined in Quantonomics' report (section C2.2), it also tested the 'half-normal' distribution of inefficiencies, as an alternative to the standard truncated-normal assumption.[98] This involved restricting the mean of the inefficiency distribution (the 'mu' parameter) to zero. Using this specification convergence was achieved. However, while convergence was reached with the use of the half-normal, the resulting efficiency scores remain anomalous. As a result, this is not one of the priority areas that we have included in the phase 1 or 2 work outlined above.

8.4 Benchmark comparison point

In our revenue determinations, we draw on the opex efficiency scores from our econometric opex cost function models (section 5) to assess the efficiency of individual DNSPs' historical and base year opex. We do this by comparing the efficiency scores of individual DNSPs against a benchmark comparison score of 0.75 (adjusted further for OEFs as set out in section 7). This reflects the upper quartile of possible efficiency scores by DNSPs.

The AER's Consumer Challenge Panel has advocated for the raising of our benchmark comparison point and a tightening of the analysis of whether a DNSP is "not materially inefficient".[99] Further, in the AER's recent 'Review of incentives schemes for Networks' it was

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97 For example, there is an unexpected positive coefficient on share of undergrounding in one of the models explored (the short period SFA Australian-specific time trend model). Opex would normally be expected to have a negative relationship with the share of undergrounding.

98 Quantonomics, *Economic Benchmarking Results for the Australian Energy Regulator's 2024 DNSP Benchmarking Report*, October 2024.

99 See CCP, *Submission to the AER Opex Productivity Growth Forecast Review Draft Decision Paper*, 20 December 2018, p. 13.

noted that one of the issues raised by consumers was whether we should use benchmarking more aggressively in setting our expenditure forecasts. In the final decision for that review we noted that as we refine our benchmarking techniques there may be a case to revise the 0.75 comparison score so that benchmarking is applied at a point closer to the efficiency frontier.[100] We also stated in our final guidance note on how we will address capitalisation differences between DNSPs that under our preferred approach any narrowing of the gap in efficiency scores raises the question of whether the benchmark comparison point of 0.75 remains appropriate and whether it should be increased.[101]

As we have previously noted, we consider our benchmark comparison point is conservative. It provides a margin for general limitations of the models with respect to the specification of outputs and inputs, data imperfections, other uncertainties when forecasting efficient opex and quantification of OEFs. We consider that it is appropriate to be conservative while our benchmarking models and OEF assessments are maturing and the underlying data and methods are being refined as set out above. It is also important to provide certainty to industry and other stakeholders because benchmarking is an input into our decision making.

However, in light of the above reviews we are proposing to commence a review of the benchmark comparison point from 2025–26. At this stage this would be after the Victorian distribution revenue determinations have been settled, and in preparation for the next ‘round’ of determinations. However, we note the submissions outlined in section 1.4.6 which considered that this review should only occur after significant maturation of our benchmarking approach and all outstanding benchmarking development issues are resolved. We will examine these arguments and concerns in the context of preparing for this review.

8.5 Further review of export services impacts on benchmarking

In March 2023 we released a final report on incentivising and measuring export service performance.[102] In that report we concluded that while the benchmarking results do not fully account for export services, and there is a need for a further review to consider what, if any, changes to the benchmarking models can be made, there is insufficient data currently available to inform such a review. The final report also noted there was insufficient evidence to conclude that the provision of export services was currently impacting the benchmarking results in a way that materially disadvantaged DNSPs in practice.

We have begun collecting export service information and have monitored this as a part of preparing the 2024 Annual Benchmarking Report. However, as noted in last year’s report, given the infancy of the data collection process, and the limited nature of the data available,

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100 AER, *Review of incentives schemes for networks, Final decision*, April 2023, p. 5.

101 AER, *How the AER will assess the impact of capitalisation differences on our benchmarking, Final Guidance Note*, May 2023, p. 21.

102 AER, *Incentivising and measuring export service performance – Final report*, March 2023.

we still do not consider there is any basis for bringing the 2027 review forward. We will continue to monitor this situation and provide further updates in future reports.

8.6 Other incremental issues

In addition to the above, we consider the following incremental improvements should be made over time. These will be progressed as a part of preparation of our annual benchmarking reports or revenue determination processes as appropriate:

- Data refinements in response to our annual review of economic benchmarking RIN data and data issues identified by stakeholders. This includes the ongoing treatment of lease and SaaS implementation costs, whether GSL payments should be included in benchmarking, and inconsistencies in data relating to emergency response.
- Improving the way we measure the quantity of lines and cables inputs. We collect DNSP-specific voltage capacity data, measured in megavolt amperes (MVA), for lines and cable by broad voltage category, and ask DNSPs to allow for operating constraints. However, DNSPs have adopted a wide range of, and in some cases, frequently changing methods to estimate the constrained MVAs. We plan to explore alternative measures to improve consistency, including 'nameplate' capacity of the installed lines and cables. To reduce the data burden on DNSPs, this information could be collected for a 'snap shot' year for each DNSP and those values applied to other years for the DNSP.
- Examining the weight allocated to the reliability output in the PIN models and whether it should be capped in some way to account for year-to-year fluctuations in exogenous factors, primarily weather, that unduly impact reliability performance and productivity growth results. Currently, the reliability output, customer minutes off-supply, enters the models as a negative output and is weighted by the value of customer reliability. It is already calculated exclusive of major event days and 'excluded' outages.
- Continuing to improve and update the quantification of material OEFs, working with DNSPs. Improving the data and quantification of the vegetation management OEF will be a future focus, as discussed in section 7. We also intend to implement any potential incremental refinements to our approach to other OEFs where appropriate. However, at this stage it is unlikely that we will undertake a holistic review of all OEFs and will more likely make incremental improvements through the revenue determination processes.
- Following the inclusion of emissions reduction as one of the National Energy Objectives, we will consider the impact, if any, on our benchmarking of DNSPs. This will likely include if / how emissions reductions are / should be captured in the benchmarking models, particularly on the input side, but also on the output side, including any interdependencies with consumer energy resources hosting capacity and export services.
- If and how the Northern Territory DNSP Power and Water should be included in our benchmarking.

Shortened forms

Term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AGD	Ausgrid
AND	AusNet (distribution)
AUC	Annual User Cost (of capital)
Capex	Capital expenditure
CIT	CitiPower
DNSP	Distribution Network service Provider
END	Endeavour Energy
ENX	Energex
ERG	Ergon Energy
ESS	Essential Energy
EVO	Evoenergy
JEN	Jemena
MPFP	Multilateral Partial Factor Productivity
MTFP	Multilateral Partial Factor Productivity
MW	Megawatt
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
Opex	Operating Expenditure
PCR	Powercor
PFP	Partial Factor Productivity
PIN	Productivity Index Number
PPI	Partial Productivity Indicator
RAB	Regulatory Asset Base
RMD	Ratcheted Maximum Demand

Term	Definition
RIN	Regulatory Information Notice
SAP	SA Power Networks
SaaS	Software-as-a-service
TFP	Total Factor Productivity
TND	TasNetworks (distribution)
UED	United Energy
WACC	Weighted Average Cost of Capital

Glossary

Term	Definition
Capital deepening	Capital deepening refers to an increase in the capital-labour ratio or an increase in the amount of capital per worker. This can occur through an increase in capital stock or through a decrease in the number of workers.
Efficiency	A DNSP's benchmarking results relative to other DNSPs reflect that network's relative efficiency, specifically their cost efficiency. DNSPs are cost efficient when they produce services at least possible cost given their operating environments and prevailing input prices.
Inputs	Inputs are the resources DNSPs use to provide services.
LSE	Least Squares Econometrics. LSE is an econometric modelling technique that uses 'line of best fit' statistical regression methods to estimate the relationship between inputs and outputs. Because they are statistical models, LSE operating cost function models with firm dummies allow for economies and diseconomies of scale and can distinguish between random variations in the data and systematic differences between DNSPs.
MPFP	Multilateral partial factor productivity is a PIN technique that measures the relationship between total output and one input. It allows both partial productivity levels and growth rates to be compared between entities (networks) and over time.
MTFP	Multilateral total factor productivity is a PIN technique that measures the relationship between total output and total input. It allows both total productivity levels and growth rates to be compared between entities (networks) and over time. These results are used in this report to measure and compare changes in 'relative productivity' over time.
Network services opex	Operating expenditure (opex) for network services. It excludes expenditure associated with metering, customer connections, street lighting, ancillary services and solar feed-in tariff payments.
OEFs	Operating environment factors are factors beyond a DNSP's control that can affect its costs and benchmarking performance.
Opex	Operation and maintenance expenditure
Outputs	Outputs are quantitative or qualitative measures that represent the services DNSPs provide.
PIN	Productivity index number techniques determine the relationship between inputs and outputs using a mathematical index.
PPI	Partial performance indicator are simple techniques that measure the relationship between one input and one output.
RMD	Ratcheted maximum demand is the highest value of maximum demand for each DNSP, observed in the time period up to the year in question. It recognises capacity that has been used to satisfy demand and gives the

Term	Definition
	DNSP credit for this capacity in subsequent years, even though annual maximum demand may be lower in subsequent years.
SFA	Stochastic Frontier Analysis. SFA is an econometric modelling technique that uses advanced statistical methods to estimate the frontier relationship between inputs and outputs. SFA models allow for economies and diseconomies of scale and directly estimate efficiency for each DNSP relative to the estimated best practice frontier.
TFP	Total factor productivity is a PIN technique that measures the relationship between total output and total input over time. It allows total productivity changes of a single entity (e.g. distribution industry or DNSP) to be compared over time.
VCR	Value of Customer Reliability. VCR represents a customer's willingness to pay for the reliable supply of electricity.

A References and further reading

Several sources inform this benchmarking report. These include ACCC / AER research and expert advice provided by Quantonomics, and previously by Economic Insights.

Quantonomics publications

The following publication explains in detail how Quantonomics applied the economic benchmarking techniques used by the AER:

- Quantonomics, Economic Benchmarking Results for the Australian Energy Regulator's 2024 DNSP Benchmarking Report, October 2024
- Quantonomics, Economic Benchmarking Results for the Australian Energy Regulator's 2023 DNSP Benchmarking Report, November 2023 (link)
- Quantonomics, Economic Benchmarking Results for the Australian Energy Regulator's 2022 DNSP Benchmarking Report, November 2022 (link)

Economic Insights publications

The following publications explain in detail how Economic Insights developed and applied the economic benchmarking techniques used by the AER.

- Economic Insights, Economic Benchmarking Results for the Australian Energy Regulator's 2021 DNSP Benchmarking Report, 12 November 2021 (link)
- Economic Insights, Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Benchmarking Report, 13 October 2020 (link)
- Economic Insights, AER Memo Revised files for 2019 DNSP Economic Benchmarking Report, 24 August 2020
- Economic Insights, Economic Benchmarking Results for the Australian Energy Regulator's 2019 DNSP Benchmarking Report, 16 October 2019 (link)
- Economic Insights, Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Benchmarking Report, 9 November 2018 (link)
- Economic Insights, Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report, 31 October 2017
- Economic Insights, Memorandum – DNSP Economic Benchmarking Results Report, 4 November 2016 (link)
- Economic Insights, Memorandum – DNSP MTFP and Opex Cost Function Results, 13 November 2015 (link)
- Economic Insights, Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs, 22 April 2015 (link)
- Economic Insights, Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs, 17 November 2014 (link)
- Economic Insights, Economic Benchmarking of Electricity Network Service Providers, 25 June 2013.

ACCC/AER publications

These publications provide a comprehensive overview of the benchmarking approaches used by overseas regulators.

- ACCC/AER, Benchmarking Opex and Capex in Energy Networks – Working Paper no. 6, May 2012 (link)
- ACCC/AER, Regulatory Practices in Other Countries – Benchmarking opex and capex in energy networks, May 2012 (link)
- WIK Consult, Cost Benchmarking in Energy Regulation in European Countries, 14 December 2011 (link).

AER distribution determinations

The AER applies economic benchmarking to assess the efficiency of total forecast opex as proposed by distribution network service providers. These decisions provide examples of how the AER has applied benchmarking in its decision making:

- AER, Draft Decision, Ergon Energy Electricity Distribution Determination 2025–30 – attachment 6 – Operating expenditure, September 2024 (link)
- AER, Final Decision, Evoenergy distribution determination 2024–29 – Attachment 6 – Operating Expenditure, April 2024 (link)
- AER, Draft Decision, Evoenergy distribution determination 2024–29 - Attachment 6 - Operating Expenditure, September 2021 (link)
- AER, Final Decision, Jemena distribution determination 2021–26 - Attachment 6 - Operating Expenditure, April 2021 (link)
- AER, Draft Decision, Jemena distribution determination 2021–26 - Attachment 6 - Operating Expenditure, September 2020 (link)
- AER, Final Decision, AusNet Services distribution determination 2021–26 - Attachment 6 - Operating Expenditure, April 2021 (link)
- AER, Draft Decision, Ergon Energy distribution determination 2020–21 to 2024–25 - Attachment 6 - Operating Expenditure, October 2019 (link)
- AER, Draft Decision, SA Power Networks distribution determination 2020–21 to 2024–25 - Attachment 6 - Operating Expenditure, October 2019 (link)
- AER, Draft Decision, Ausgrid distribution determination 2019–20 to 2023–24 - Attachment 6 - Operating Expenditure, November 2018 (link)
- AER, Final Decision, Ausgrid distribution determination 2014–15 to 2018–19, January 2019 (link)
- AER, Final Decision, Jemena distribution determination 2016 to 2020 - Attachment 7 - Operating Expenditure, May 2016, p. 7–22 (link)
- AER, Final Decision, Endeavour Energy distribution determination 2015–16 to 2018–19 - Attachment 7 - Operating Expenditure, April 2015 (link)
- AER, Preliminary decision, Ergon Energy determination 2015–16 to 2019–20 - Attachment 7 - Operating Expenditure, April 2015 (link).

B Benchmarking data

This appendix contains further information on the output and input data used in this report.

Inputs include a mix of the infrastructure assets needed to distribute electricity to customers and the network opex to run and maintain the network. DNSPs primarily exist to provide customers with access to a safe and reliable supply of electricity and a range of outputs have been selected to reflect this goal.[103]

Categories of inputs and outputs used in benchmarking

Inputs:

Capital stock (assets) refers to the physical assets DNSPs invest in to replace, upgrade or expand their networks. Electricity distribution assets provide useful service over a number of years or even several decades. We split capital into:

- overhead distribution (below 33kV) lines
- overhead sub-transmission (33kV and above) lines
- underground distribution cables (below 33kV)
- underground sub-transmission (33kV and above) cables
- transformers and other capital.

Operating expenditure (opex) is expenditure needed to operate and maintain a network. Opex is an immediate input into providing services and is fully consumed within the reporting year.

Outputs:

- Customer numbers. The number of customers is a measure of the scale of the DNSP and the services a DNSP must provide. We measure the number of customers as the number of active connections on a network, represented by each energised national metering identifier.
- Circuit length. This reflects the distances over which DNSPs deliver electricity to their customers.
- Ratcheted maximum demand (RMD). DNSPs endeavour to meet the demand for energy from their customers when that demand is greatest. This means that they must build and

103 The 17 November 2014 Economic Insights report referenced in Appendix A details the input and output weights applied to constructing the productivity index numbers. The 9 November 2018 Economic Insights report contains further information on the updated output weights, while the 13 October 2020 Economic Insights report contains detail on a correction to these weights due to a coding error.

operate their networks with sufficient capacity to meet the expected peak demand for electricity.[104]

- Energy delivered (MWh). Energy throughput is a measure of the amount of electricity that DNSPs deliver to their customers. This output is included only in the PIN models, not in the econometric opex cost function models.
- Reliability (Customer minutes off-supply). Reliability measures the extent to which networks are able to maintain a continuous supply of electricity. Minutes off-supply enters as a negative output and is weighted by the value of customer reliability. This output is included only in the PIN models, not in the econometric opex cost function models.
- Share of undergrounding. The econometric opex cost function models also include a variable for the proportion of a DNSP's total circuit length that are underground. DNSPs with more underground cables will, all else equal, face less maintenance and vegetation management costs and fewer outages.

The November 2014 Economic Insights referenced in Appendix A details the rationale for the choice of these inputs and outputs.

The econometric modelling differs from the other benchmarking techniques in that it uses Australian and overseas data. The lack of variability in the Australian DNSP data means that sufficiently robust results cannot be produced with Australian DNSP data alone using econometric methods. When the economic benchmarking program commenced, Economic Insights incorporated comparable data from electricity DNSPs in Ontario and New Zealand to increase the size of the dataset and enable more robust estimation of the opex cost function models. Sensitivity analysis of the econometric opex benchmarking results (using cost functions generated with and without the overseas data) indicated that the addition of the overseas data improved the robustness of the econometric opex models (by allowing better estimation of the opex cost function parameters) without distorting the estimation of individual DNSPs' efficiency results. Appendix A contains references to further reading on how Economic Insights incorporated overseas data into the econometric models and the sensitivity analyses. This approach with the international data continues to be used in the benchmarking work undertaken by Quantonomics to update for the 2023 data.

To prepare this year's report, each DNSP provided the AER with input and output data from their businesses as defined in standardised economic benchmarking RINs. The economic benchmarking RINs require all DNSPs to provide a consistent set of data, which is verified by each DNSP's chief executive officer and independently audited. We separately tested and validated the data provided by the networks. Quantonomics prepared the benchmarking

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104 The economic benchmarking techniques use 'ratcheted' maximum demand as an output rather than observed maximum demand. Ratcheted maximum demand is the highest value of peak demand observed in the time period up to the year in question for each DNSP. It recognises capacity that has been used to satisfy demand and gives the DNSP credit for this capacity in subsequent years, even though annual maximum demand may be lower in subsequent years.

results using the set of agreed benchmarking techniques.[105] We provided the DNSPs with a draft version of the benchmarking report to allow each network to provide feedback on the data and results before we publicly released the final benchmarking report.[106]

The complete data sets for all inputs and outputs from 2006 to 2023, along with the Basis of Preparation provided by each DNSP, are published on our website.[107]

B.1 Outputs

The techniques in this report measure output using some or all of customer numbers, circuit line length, maximum demand, energy throughput and reliability.

Customer numbers

The primary function of a distribution network is providing its customers with access to electricity. Regardless of how much electricity a customer consumes, infrastructure is required to connect every customer to the network. The number of customers, therefore, is a measure of the services a DNSP provides.[108]

Figure B.1 shows the average customer numbers of each DNSP over the five-year period from 2019–23.

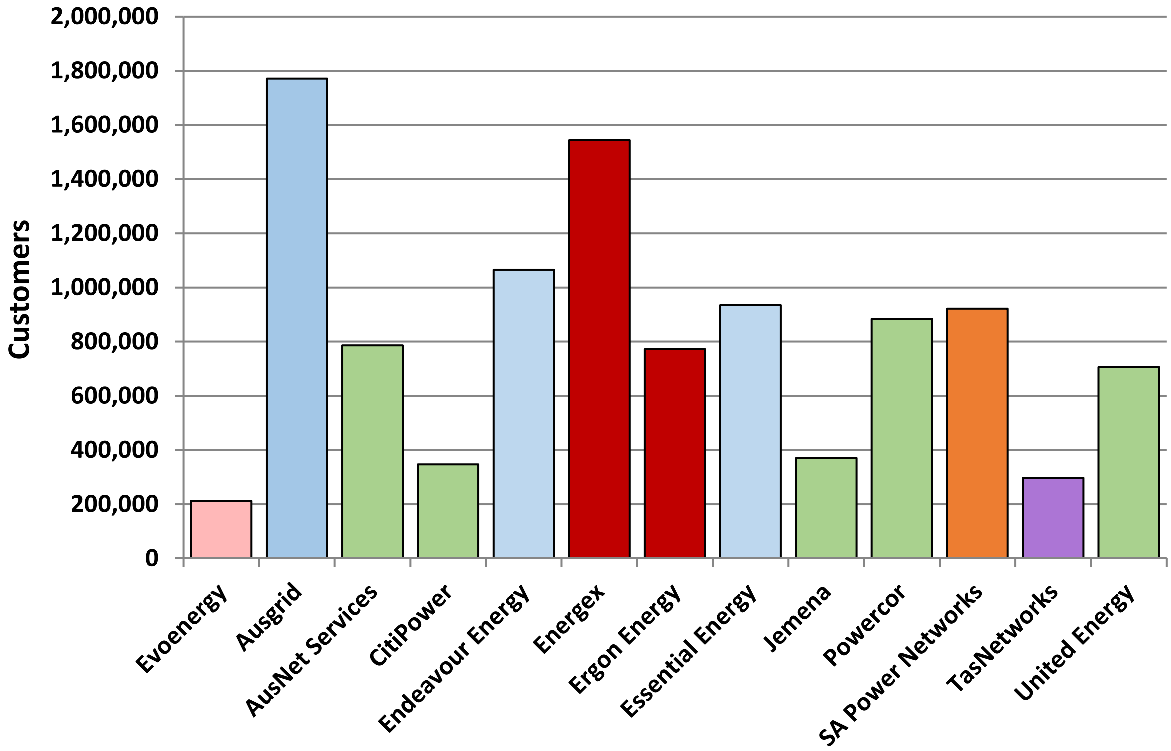
105 The Quantonomics report outlining the results for this year's report and the data and benchmarking techniques used can be found on the AER's benchmarking website.

106 NER, cll. 8.7.4(c)(1) and 8.7.4(c)(2).

107 This dataset is available at www.aer.gov.au/publications/reports/performance.

108 We measure the number of customers as the number of active connections on a network, represented by each energised national metering identifier.

Figure B.1 five-year average customer numbers by DNSP (2019–23)



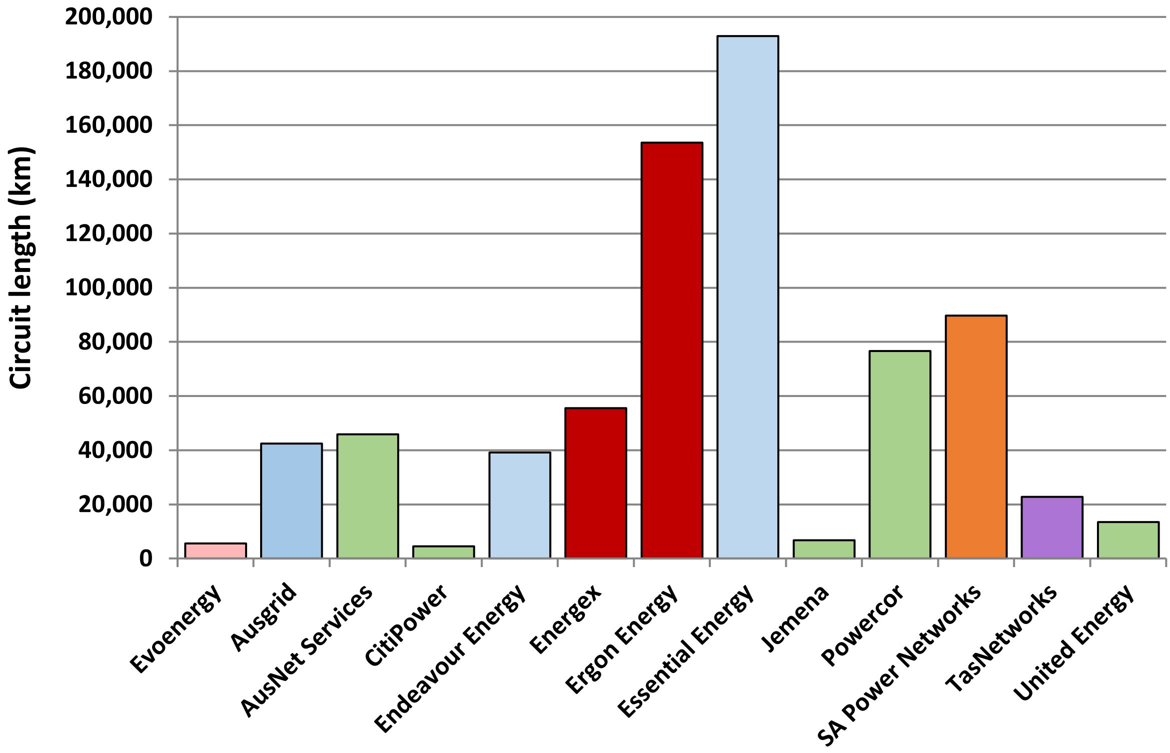
Source: Economic Benchmarking RIN.

Circuit line length

Line length reflects the distances over which DNSPs deliver electricity to their customers. To provide their customers with access to electricity, DNSPs must transport electricity from the transmission network to their customers' premises. DNSPs will typically operate networks that transport electricity over thousands of kilometres.

In addition to measuring network size, circuit length also approximates the line length dimension of system capacity. System capacity represents the amount of network assets a DNSP must install and maintain to supply consumers with the quantity of electricity demanded at the places where they are located. Figure B.2 shows each DNSP’s circuit length, on average, over the five years from 2019–23.

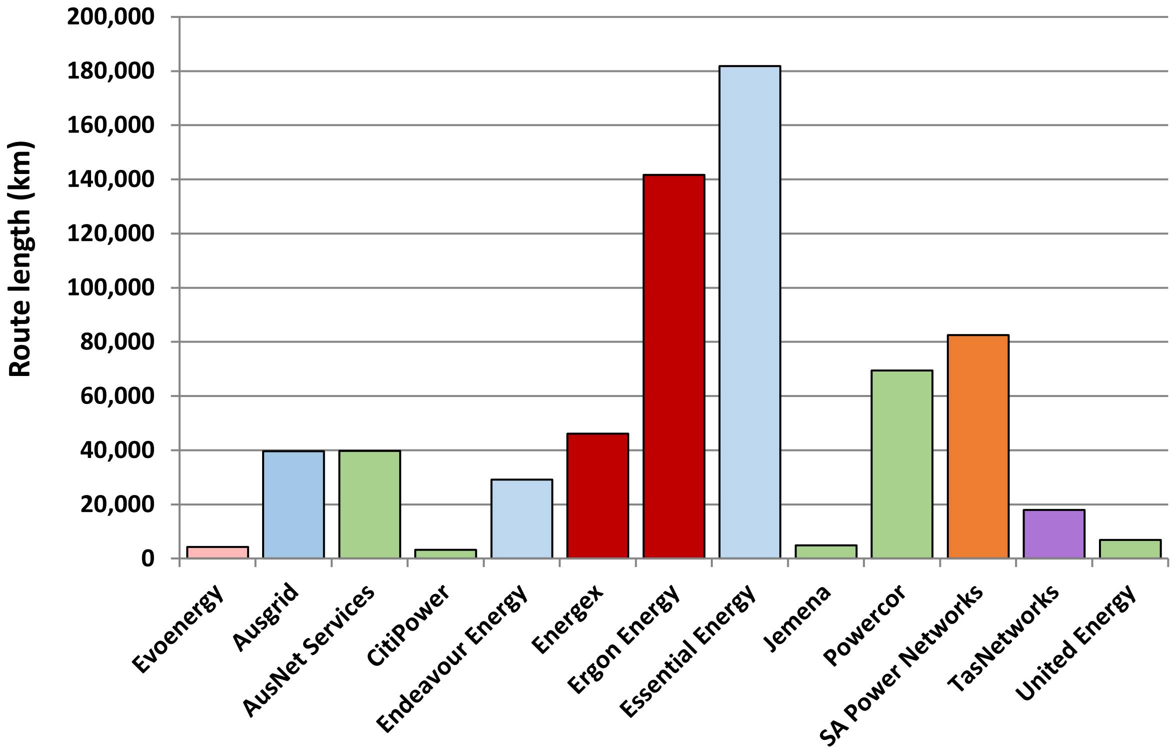
Figure B.2 Five year average circuit line length by DNSP (2019–23)



Source: Economic Benchmarking RIN.

For PPI metrics, we use route (rather than circuit) length to calculate customer density because it is a measure of a DNSP's physical network footprint (because it does not count multiple circuits on the same route). Comparison between Figure B.3 and Figure B.4 demonstrates that, for all DNSPs, route length is always shorter than, but closely related to circuit length. The ratio of route length to circuit length, however, varies by DNSP.

Figure B.3 Five year average route line length by DNSP (2019–23)



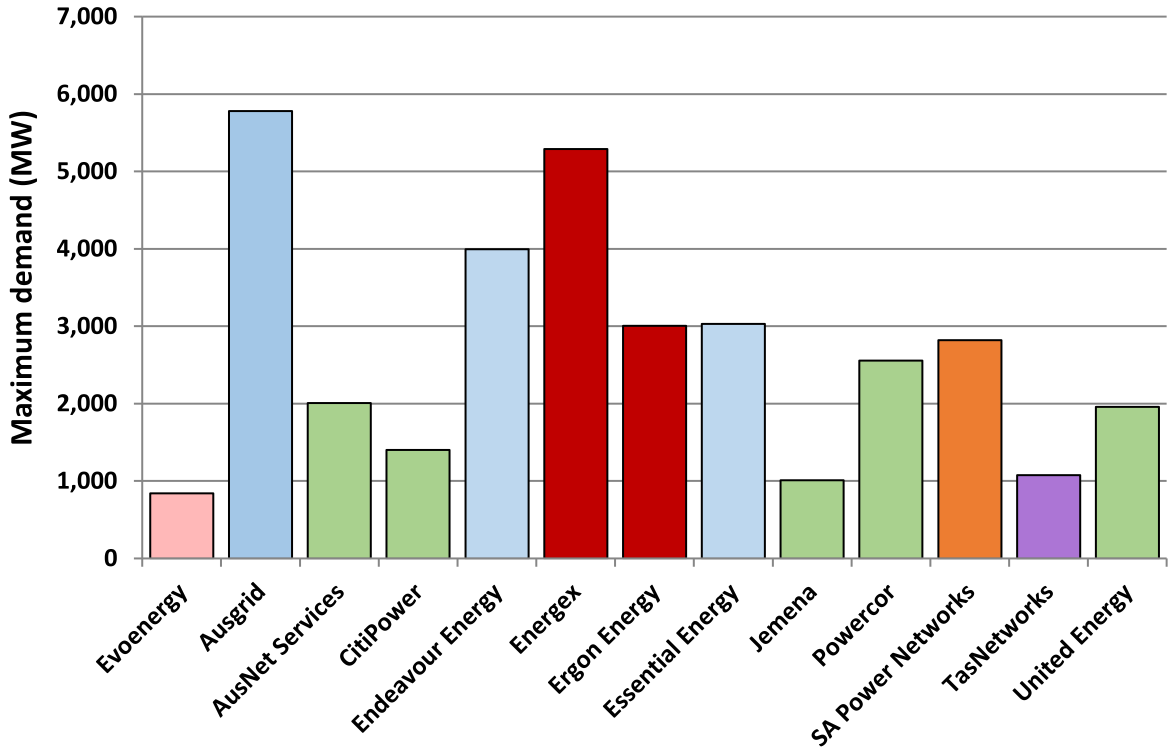
Source: Economic Benchmarking RIN.

Maximum demand

DNSPs are required to meet and manage the demand of their customers. This means that they must build and operate their networks with sufficient capacity to meet the expected peak demand for electricity. Maximum demand is a measure of the overall peak in demand experienced by the network. The maximum demand measure we use is non-coincident summated raw system annual maximum demand, at the transmission connection point, measured in megawatts (MW).

Figure B.4 shows each DNSP's maximum demand, on average, over the five years from 2019–23.

Figure B.4 Five year average maximum demand by DNSP (2019–23)

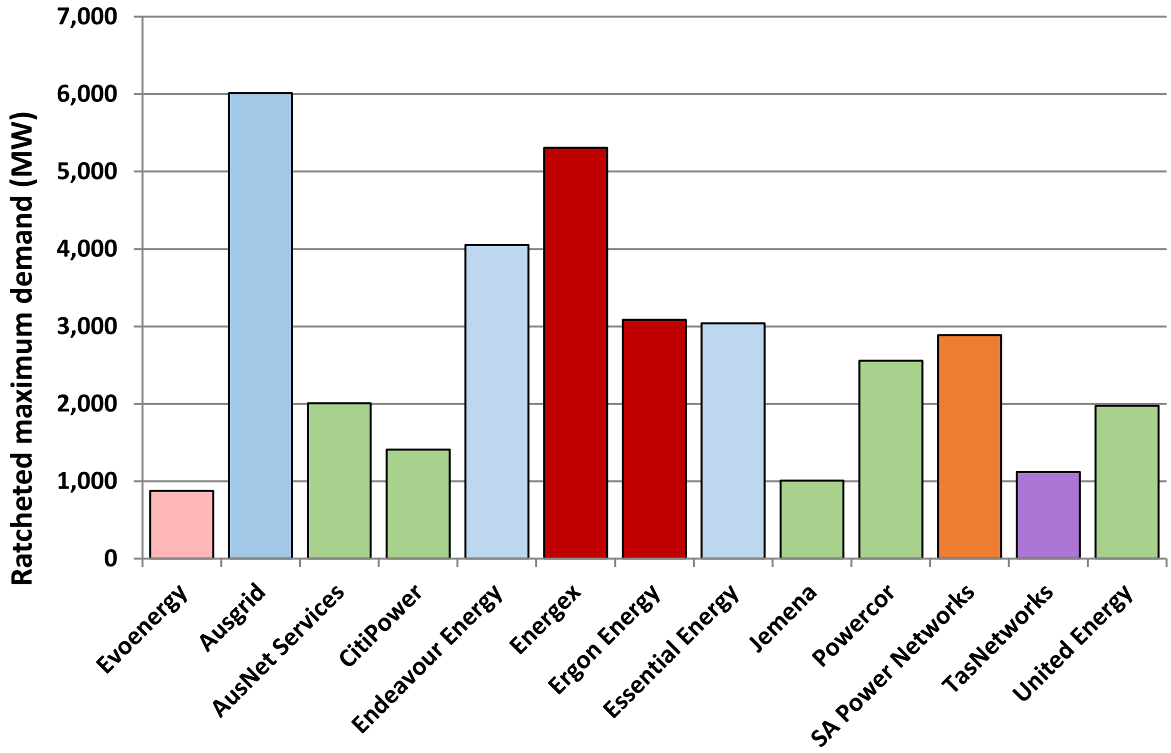


Source: Economic Benchmarking RIN.

The economic benchmarking techniques use 'ratcheted' maximum demand as an output rather than observed maximum demand. Ratcheted maximum demand is the highest value of peak demand observed in the time period up to the year in question for each DNSP. It thus recognises capacity that has actually been used to satisfy demand and gives the DNSP credit for this capacity in subsequent years, even though annual peak demand may be lower in subsequent years.

Figure B.5 shows each DNSP's ratcheted maximum demand, on average, over the five years from 2019–23.

Figure B.5 Five year average ratcheted maximum demand by DNSP (2019–23)



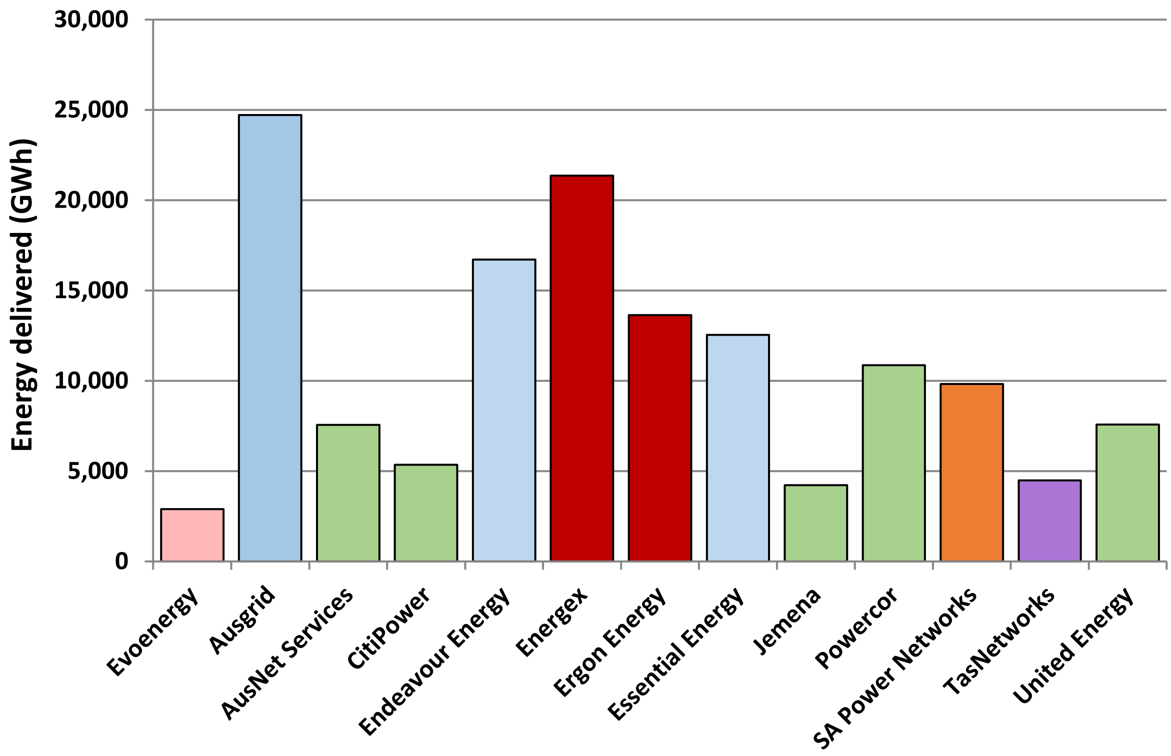
Source: Economic Benchmarking RIN.

Energy delivered

Energy delivered is a measure of the amount of electricity that DNSPs deliver to their customers. While energy throughput is not considered a major driver of costs (distribution networks are typically engineered to manage maximum demand rather than throughput) energy throughput reflects a service provided directly to customers and is a key part of what they pay for in their bills. Energy delivered is measured in Gigawatt hours (GWh).

Figure B.6 shows each DNSP's energy delivered, on average, over the five years from 2019–23.

Figure B.6 Five year average energy delivered by DNSP (2019–23)



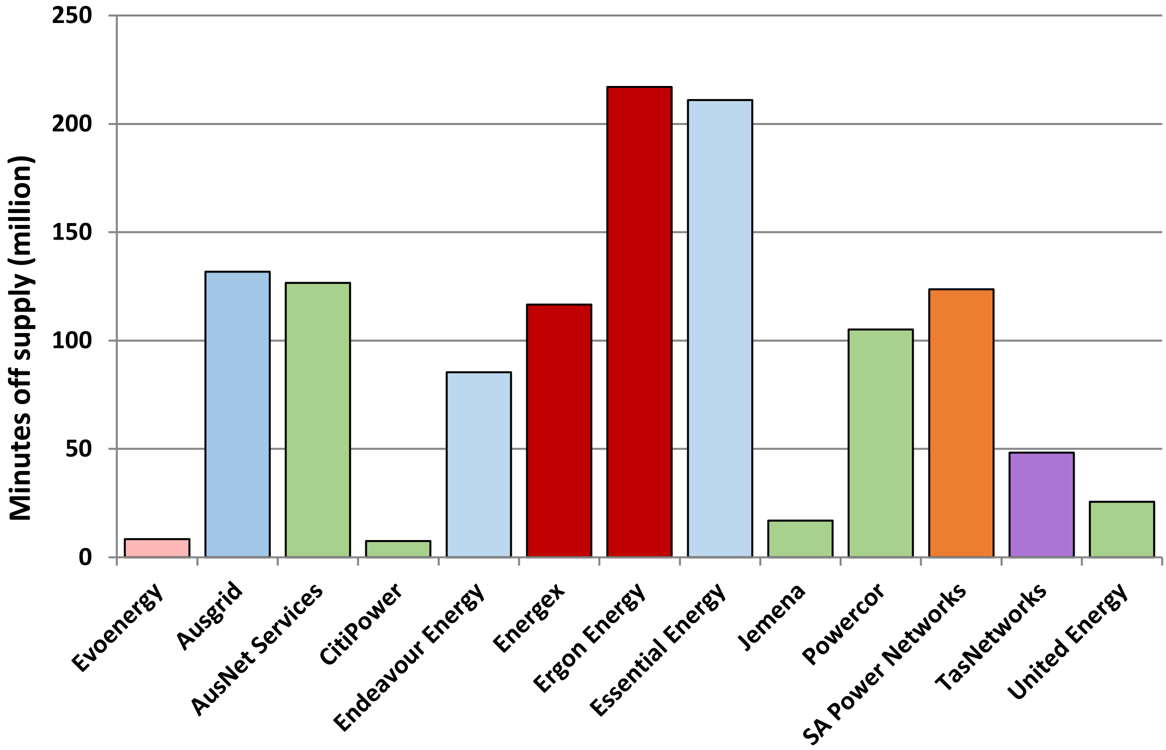
Source: Economic Benchmarking RIN.

Reliability

Another dimension of the outputs of DNSPs is the reliability of their electricity supply. This is commonly measured as the average number of customer minutes off-supply (per customer, per annum) or the average annual number of interruptions per customer. Figure B.7 presents for each DNSP the average number of minutes off-supply (per customer, per year) over the 2019–23 period, excluding the effects of major events, planned outages and transmission outages.

There are other measurements of reliability, such as the Institute of Electrical and Electronics Engineers' frequency and duration of interruptions to supply per customer. For productivity measurement purposes we use the number of customer minutes off-supply aggregated across all customers as the reliability output.

Figure B.7 Five year average customer minutes off supply by DNSP (2019–23)



Source: Economic Benchmarking RIN

B.2 Inputs

The inputs used in this report are capital (assets) and opex. DNSPs use a mix of assets and opex to deliver services. Electricity assets can provide useful service over several decades. However, benchmarking studies typically focus on a shorter period of time.

We use physical measures of capital inputs in our time series multilateral TFP and panel MTFP analysis. Using physical values for capital inputs has the advantage of best reflecting the physical depreciation profile of DNSP assets. Our time series multilateral TFP and panel MTFP measures use five physical measures of capital inputs: the capacity of transformers, overhead lines of 33kV and above, overhead lines below 33kV, underground cables of 33kV and above, and underground cables below 33kV. The multilateral TFP and MTFP analyses also use constant dollar opex as an input. The November 2014 Economic Insights report referred to in Appendix A provides further detail on the capital inputs for these measures.

For the purpose of PPI analysis we use the real value of the regulatory asset base as the proxy for assets as the starting point in deriving the real cost of using those assets. To be consistent with Economic Insights' and Quantonomics' multilateral TFP and MTFP analyses, and in response to a submission by Ausgrid,[109] we have adjusted the PPI analysis to remove assets associated with the first step of the two-step transformation at the zone substation level for those DNSPs with more complex system structures. This allows better like-with-like comparisons to be made across DNSPs.

The AUC of capital[110] has the advantage of reflecting the total cost of assets for which customers are billed on an annual basis, using the average return on and of capital over the period. This accounts for variations in the return on capital across DNSPs and over time.

Table B.1 presents measures of the cost of network inputs relevant to opex and assets for all DNSPs. We have presented the average annual network costs over five years in this table to moderate the effect of any one-off fluctuations.

Table B.1 Average annual input costs for 2019–23 ($m, 2023)

DNSP	Opex	AUC
Evoenergy (EVO)	79.2	91.1
Ausgrid (AGD)	449.0	894.2
AusNet (AND)	245.2	357.2
CitiPower (CIT)	82.1	129.1
Endeavour Energy (END)	310.3	376.7
Energex (ENX)	456.7	485.0
Ergon Energy (ERG)	479.5	518.2
Essential Energy (ESS)	486.6	489.3
Jemena (JEN)	91.7	114.7
Powercor (PCR)	257.2	282.4
SA Power Networks (SAP)	297.4	440.3
TasNetworks (TND)	111.7	137.3
United Energy (UED)	134.5	216.4

Source: Economic Benchmarking RIN; AER analysis.

109 Ausgrid, *Submission on the 2016 draft distribution benchmarking report*, 14 October 2016, p. 3.

110 The AUC of capital represents asset costs and is described in section 1.1.

C Refinements to the AUC of capital calculation methodology

This appendix describes the refinements made to the AUC calculation methodology, and the impact of these refinements on the observed AUC of capital across each DNSP. Further technical information on the methodological refinement can be found in appendix A.5 of Quantonomics' report.[111]

C.1 Changes in the way we calculate AUC

The AUC of capital is comprised of the return on capital plus regulatory depreciation plus the benchmark tax liability. As noted in section 1.2, the capital inputs are weighted using the AUC of capital, which reflect the costs DNSPs face for their capital inputs, i.e. asset costs. In the initial preparation of results for this year's report, we observed declining AUCs and some instances of negative AUCs across asset classes. This was found to be particularly prevalent in 2022 and 2023. Our analysis indicated these outcomes were driven by rapid changes in the inflation environment of recent years, and in particular the recent divergence between actual and expected inflation.

Until recently, actual inflation has tracked expected inflation fairly closely. However, actual inflation since 2021 has been significantly higher than expected inflation. This divergence in inflation rates leads to unduly declining AUCs due to:

- Declining or negative regulatory depreciation, due to the impact of the high recent actual inflation rate applied in calculating the inflation addition component[112].
- Relatively stable return on capital, due to the rate of return component reflecting much lower expected inflation.[113]

Therefore, the return on capital component was not sufficiently offsetting the significantly reduced (and in some cases negative) regulatory depreciation component, leading to the net result of falling or negative AUCs.

A more minor but additional factor to the declining AUCs was a reduced or negative benchmark tax liability component. This reflected the low or negative regulatory deprecation arising from the high inflation addition.

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111 Quantonomics, *Economic Benchmarking Results for the Australian Energy Regulator's 2024 DNSP Benchmarking Report*, October 2024.

112 The deduction of the Inflation Addition from straight-line depreciation in forming regulatory depreciation is required within a nominal WACC approach to reverse a double-count of the impact of inflation.

113 In the nominal WACC, the observed nominal risk free rate reflects the real risk free rate and market-expected inflation.

Given that AUCs determine the weights on capital inputs, this was increasing the relative input weight assigned to opex in the MTFP and MPFP modelling. Beyond this impact, rapidly declining AUCs would also be reflected in decreasing total cost in our total cost PPIs presented in section 6. We first noted the mechanism by which significant increases in the rate of inflation were impacting AUCs in last year's benchmarking report.[114] We therefore considered that retaining the previous AUC methodology was not appropriate as rapid changes in inflation, rather than capital stock, would be driving the changes in AUC and input weights used in the PIN modelling as well as the PPI outcomes.

To address this, we have refined our AUC methodology by the use of the real WACC, rather than nominal WACC, to calculate the return on capital component. Under this approach, the real WACC is derived using a combination of observed nominal risk-free rates and the expected rate of inflation. With the move to a real WACC approach, there is no longer a need to remove the inflation addition component from regulatory depreciation, and hence the actual inflation rate no longer figures in the AUC calculation. The changes in the AUC of capital formulas are outlined below.

Previous approach (as used in previous benchmarking reports):

$$AUC_t = NWACC_t \cdot RAB_t^B + RegDep_t + Tax_t$$

where:

- RAB_t^B is the RAB at the beginning of period *t*
- $NWACC_t$ is the Nominal Vanilla WACC, and
- Tax_t is the benchmark tax liability, in period *t*
- $RegDep_t$is regulatory depreciation defined as:

$$RegDep_t = SLD_t - IA_t$$

where:

- SLD_t is straight-line depreciation and
- IA_t is the Inflation Addition in period t.

Source: Quantonomics.

Current approach (as used in the 2024 Annual Benchmarking Report):

$$AUC_t = RWACC_t \cdot RAB_t^B + SLD_t + Tax_t$$

114 AER, *2023 Annual Benchmarking Report – distribution network service providers*, November 2023, p. 100.

where:

- RAB_t^B is the RAB at the beginning of period *t*
- $RWACC_t$ is the Real Vanilla WACC, and
- Tax_t is the benchmark tax liability, in period *t*
- SLD_t is the straight-line depreciation at time *t*

Source: Quantonomics.

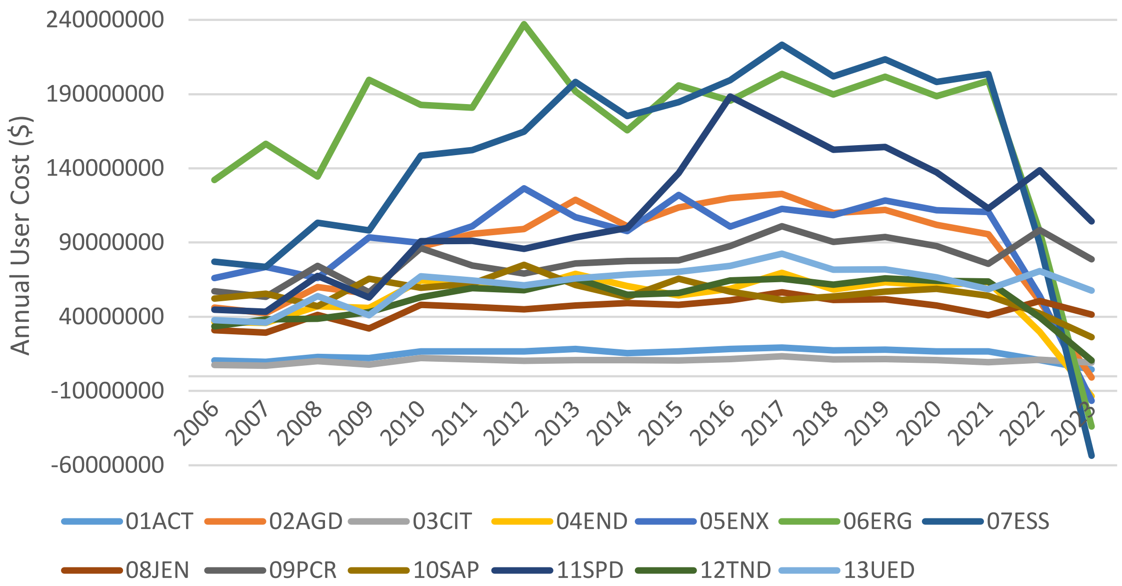
The key consideration in adopting the refined approach was to eliminate the discrepancies that arose from different rates of inflation applied to the return on equity and return of equity components of AUC. Under the refined approach, the rate of return is derived in an ex-ante manner, consistent with the AER's broader approach to WACC. The revised approach removes the need to deduct the inflation addition component of regulatory depreciation. This circumvents the impact of any divergence between the actual and expected inflation rate. As a result of this change, a greater degree of stability of AUCs over time can be expected.

C.2 Impact of the AUC changes

The impact of the above changes to the AUC methodology is illustrated in Figure C.1 and Figure C.2 using the AUC of capital values for overhead distribution assets as an example. Under the previous approach, shown in Figure C.1, reported AUC values for overhead assets display a sharp downward trend from 2021 to 2023, reporting near-zero or negative values. Under the revised approach, shown in Figure C.2, the AUC of capital appear to be more stable and have reported an increase in 2023, which reflect the underlying market movements.

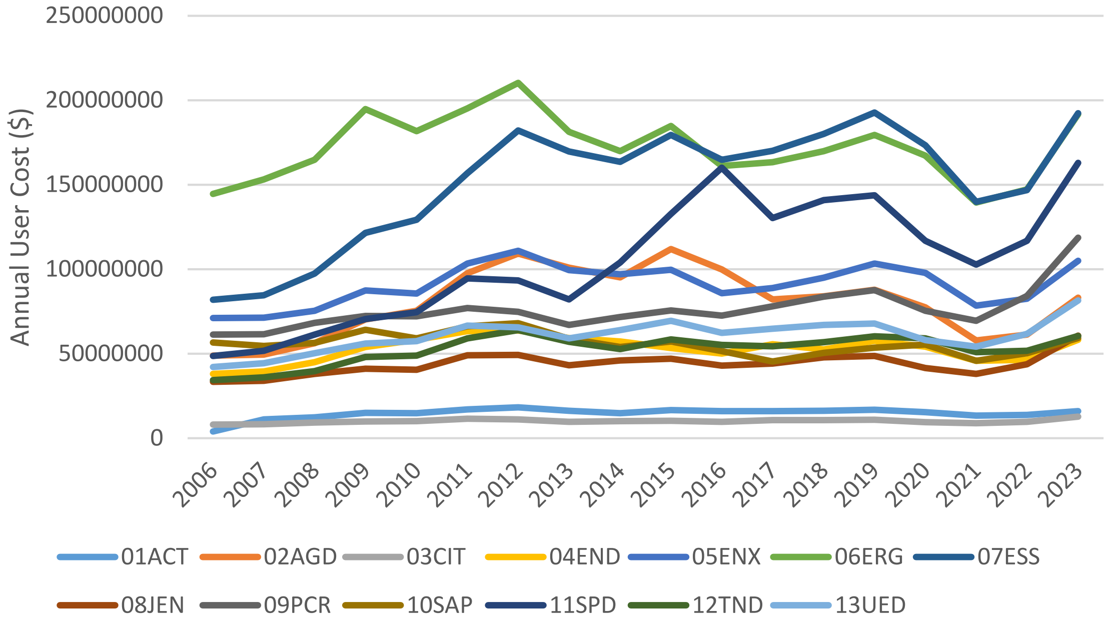
We consider the refined AUC calculation methodology is more fit-for-purpose and serves as a better measure of the cost of DNSPs' accumulated capital stock.

Figure C.1 AUC for 'Overhead distribution' assets under the previous approach



Source: AER Analysis

Figure C.2 AUC for 'Overhead distribution' assets under the refined approach



Source: AER Analysis