Taking account of heterogeneity between networks when conducting economic benchmarking analysis

A REPORT PREPARED FOR ERGON ENERGY

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AER's analysis

In developing its Draft Decisions for the NSW/ACT distribution network service providers (DNSPs), the AER has undertaken its first attempt at comparative benchmarking, as is required under the National Electricity Rules. The benchmarking results prepared by its consultants, Economic Insights (EI), identified a very large spread in performance across the businesses in its sample, ranging from 40% to 95% for the Australian DNSPs.

Relying mechanistically on these results, the AER has proposed very significant reductions to the base-year opex cost allowances of the NSW/ACT DNSPs over the 2014-2019 period, as shown in Table 1 below.

Table 1: Base-year opex reductions determined by the AER's opex benchmarking analysis

	Efficiency scores from EI's analysis	AER's adjustments for 'exogenous factors'	Final base-year opex reductions determined by the AER
Ausgrid	45%	10%	43%
ActewAGL	40%	30%	40%
Essential	55%	10%	30%
Endeavour	59%	10%	24%

Source: Economic Insights, Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs, 17 November 2014

In January 2015, Frontier produced a report for Networks NSW in which we reviewed in detail the robustness of the benchmarking analysis that EI had undertaken to inform the AER's Draft Decisions.[1] We identified material flaws with EI's analysis, including its failure to take into account the vast heterogeneity of circumstance, and hence cost to serve, between DNSPs.

We concluded that EI's analysis conflated managerial efficiency with the effect of uncontrolled for differences in circumstance, i.e. latent heterogeneity. This led EI and the AER to conclude erroneously that many of the DNSPs are materially inefficient.

While we support and encourage the use of benchmarking in principle, we concluded that the AER's benchmarking analysis as it presently stands is

1 Frontier Economics, *Review of the AER's econometric benchmarking models and their application in the draft determinations for Networks NSW*, January 2015.

2 Frontier Economics, *Review of the AER's econometric benchmarking models and their application in the draft*

unreliable for the purposes of informing cost allowances for the present price reset.

Evidence of heterogeneity

This report builds on our work already completed for Networks NSW. We focus on demonstrating further and more specifically the heterogeneity in circumstance across the Australian DNSPs, focusing on Ergon, with respect to a wide range of factors including network design, population dispersion, weather and terrain.

Our investigation reveals that Ergon has almost unique circumstances in respect of the Australian sample. The most important differences between Ergon and other Australian DNSPs arise as a consequence of needing to serve a vast and sparsely-populated region, and the need to contend with the comparatively extreme environmental conditions that occur in Queensland, relative to the network in other regions. The need to design, build and operate a network to address these challenges has a material impact on Ergon's costs compared to other DNSPs that face less onerous circumstances. The AER has not controlled adequately for these factors in its benchmarking, and has interpreted erroneously the unexplained residual variation in opex in its models that results as differences in efficiency.

Evidence that Ergon's circumstances are not captured in the EI model

In our report for Networks NSW we demonstrated that much of the residual variation in opex that the AER has chosen to interpret as differences in efficiency could, in fact, be due to latent heterogeneity not taken into account in the AER's benchmarking model. We presented two alternative models, the fixed and random 'true' effects models, which did allow for the residual variation to be interpreted as latent heterogeneity, and which resulted in a much narrower range of efficiency scores.

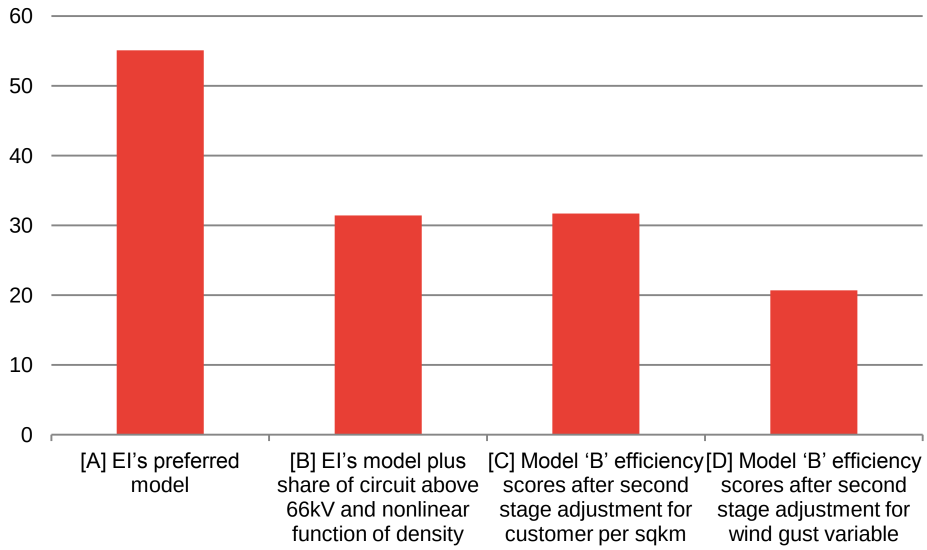
In this report, we show that some of the factors treated as latent heterogeneity in our earlier report, and as inefficiency by the AER, can be quantified and modelled as modifications to EI's benchmarking model, or adjustments to EI's efficiency scores, albeit imperfectly. In other words, we have been able to transform some the latent heterogeneity into modelled heterogeneity, and reduce the gap between the AER's benchmarking model and the 'true' effects models. We demonstrate this in two ways.

- **Within EI's benchmarking model.** First, we demonstrate the impact of accounting for some of the latent heterogeneity between DNSPs directly, by incorporating additional relevant variables (that relate to operational circumstances) into EI's existing modelling framework. Doing so narrows the efficiency gap identified by EI considerably.

- **Through a two-stage approach.** Second, we show the effect of accounting for additional factors by applying a two-stage approach, which has been suggested by, amongst others, Coelli et al (2005). This involves a regression of the efficiency scores derived from the econometric benchmarking model on additional relevant environmental variables that cannot be incorporated within EI'S modelling framework (owing to a lack of data on international comparators, for example). Doing so narrows the efficiency gap even further.

Our results are summarised in Figure 1 below, which shows it is possible to alter significantly the AER's benchmarking results by making minor changes to EI's benchmarking model and efficiency scores, casting further doubt on the validity of the AER's proposed efficiency adjustments to cost allowances.

Figure 1. Impact of minor adjustments to EI's models on efficiency spread



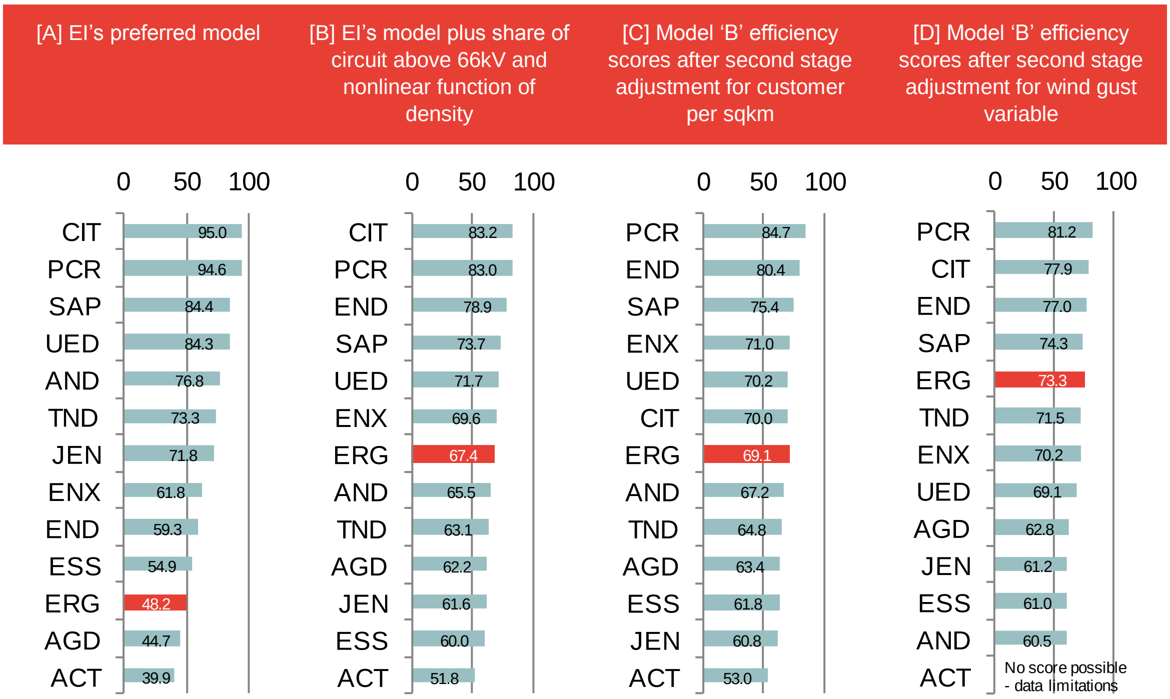
Source: Frontier; Note: We calculate the 'spread' in efficiency as the difference between efficiency score of the most and least efficiency Australian DNSP in the sample.

Figure 2 shows how the efficiency scores and rankings of individual DNSPs are affected by the further modelling we undertook. Under EI's preferred model, Ergon was identified as the third least efficient network. We show that when some of the latent heterogeneity between DNSPs is modelled, Ergon's rankings and efficiency scores improve materially. For instance:

- By modifying EI's model to account for differences between DNSPs in terms of investment in subtransmission assets, and also a nonlinear density relationship, Ergon's efficiency ranking increased from the 11th most efficient network to the 7th most efficient network. In addition, the efficiency spread between Ergon and the most efficient network narrowed from 46.8 to just 15.8.

- When we additionally accounted for differences in the number of customers per square kilometre of service area (using a two-stage adjustment approach), the efficiency spread narrowed fractionally to 15.6.
- However, when we also accounted for environmental conditions (in particular, differences in extreme wind gust speeds experienced by different DNSPs) Ergon is identified as the 5th most efficient network, and the efficiency spread narrows further to 7.9.

Figure 2: Impact of minor alternations to EI's models on efficiency scores and rankings of individual DNSPs



Source: EI analysis, Frontier analysis. Note: Scores for ActewAGL could not be derived under model [D] as data on wind gust speed were not available readily for this DNSP.

However, we emphasise strongly that these minor alternations do not mitigate the data problems we identified in our report for Networks NSW, particularly with respect to the pooling of overseas data with the Australian data, which we consider to be entirely inappropriate. We therefore do not claim to have identified the 'right models' or to have solved the problem of modelling the full extent of heterogeneity across the Australian DNSPs. Our aim, in presenting this analysis, is to demonstrate that EI's benchmarking analysis has serious deficiencies in terms of failing to account for evidently large differences in genuine operational circumstances between DNSPs. Further, we present this analysis to demonstrate that the AER's benchmarking results for the Australian DNSPs are highly sensitive to minor modifications to EI's preferred model. In our view, this is cause for significant concern in its own right, and reinforces the conclusions from our work for Networks NSW.

Ways in which latent heterogeneity may be dealt with outside the benchmarking model

Ideally, regulators would control for all the drivers of performance within a single benchmarking model. However, this is typically not possible owing to practical limitations, such as limited sample size, lack of data, and the challenges of quantifying the most important external factors that explain differences in performance (over time and/or between networks). To overcome these practical limitations, a wide range of approaches have been adopted by European regulators, including making a number of normalisations, exclusions and adjustments to their benchmarking models in an attempt to ensure that their comparisons are more like-for-like. We refer to such normalisations, exclusions and adjustments as ‘special factor adjustments’.

Whilst regulators in Europe recognise the need for such adjustments, and make these as part of their deliberations on relative efficiencies, the AER has made no meaningful attempt to make similar adjustments — notwithstanding that the heterogeneity between networks observable in Australia is vastly greater than is found in Europe. The AER’s only attempt at accounting for (a very limited number of) special circumstances in the NSW/ACT Draft Decisions involved increasing the input use of the top quartile DNSPs by 10% for the NSW networks and 30% for ActewAGL. As evidenced in our report for Networks NSW, these adjustments are arbitrary and based on a very incomplete exploration of possible differences between DNSPs. They are also wholly inadequate as they still give rise to implausibly large reductions to base year opex levels (i.e. between 13% and 45%).

The AER’s failure to allow, within its benchmarking methodology, an explicit step to account for special factors suggests strongly that its application of benchmarking falls well short of best practice. We consider that the AER should learn from the experience of regulators in Europe and make integral to its benchmarking analysis adjustments for special factors.

Recommendations to the AER

We noted in our report to Networks NSW that, whilst we support and encourage the use of benchmarking in principle, the AER’s benchmarking analysis as it presently stands is unreliable for the purposes of informing cost allowances for the present price reset. For the reasons outlined in this report, and in our report to Networks NSW businesses, the AER cannot be satisfied that a substituted expenditure forecast informed by its benchmarking analysis reasonably reflects the criteria in the National Electricity Rules.

Our analysis in this report confirms further that the AER has failed to:

- account for the vast heterogeneity of circumstance, and hence cost to serve, between DNSPs; and
- take sufficient account of special factors, and has underestimated their potential magnitude.

We recommend that the AER recognise the existence of significant latent heterogeneity between DNSPs, and account more meaningfully for this heterogeneity in its benchmarking analysis. We also recommend that the AER investigate further the special factor adjustments that are required for the DNSPs in Australia.

However, doing so would require a significant improvement in the quality of the RIN data, quantification of additional variables that are presently excluded from its coverage, and significant engagement with the DNSPs to understand their unique operational circumstances and the impact of these circumstances on costs. This would require a long and collaborative process, as evidenced by our case studies from overseas. As regulators in Europe have found, there is no single best method that can be employed uniformly to all networks, when making special factor adjustments. Therefore, the AER would need to consider these special factors on a case-by-case basis.

In our view, there is insufficient time within the present regulatory timetable to quantify the required special factor adjustments. This means that the quantification of the impact of special factors is a task for the medium-term.

For the current reset, we reinforce the conclusions in our report to Networks NSW, and recommend that the AER consider alternative approaches for accepting or substituting expenditure forecasts, which place much less reliance on the conclusions of the AER's benchmarking analysis.

1 Introduction

1.1 Background

On 27 November 2014 the Australian Energy Regulator (AER) published its Draft Decisions on the distribution determinations for the NSW/ACT distribution network service providers (DNSPs). The AER's final distribution determinations will apply to these DNSPs for the period 2015-19.

In developing its Draft Decisions, the AER has undertaken for the first time a comparative benchmarking analysis to aid its assessment of proposed expenditures by the DNSPs. This analysis has been conducted on the AER's behalf by Economic Insights (EI). EI's benchmarking analysis to assess opex efficiency has used the benchmarking Regulatory Information Notices (RIN) data submitted by 13 Australian DNSPs. In addition, in order to employ certain statistical techniques to estimate relative opex efficiency, EI has pooled the Australian RIN data with data on distribution networks in Ontario and New Zealand. Based on the findings of its benchmarking study, EI has recommended to the AER very significant cost reductions for all of the NSW/ACT DNSPs. The AER proposed in its Draft Decisions that these reductions be made upfront to base year expenditure levels.

In January 2015 we produced a report for Networks NSW in which we reviewed in detail the robustness of the benchmarking analysis that EI had undertaken to inform the AER's Draft Decisions.[2] We identified several problems with EI's analysis that, in our view, are so severe as to render the analysis completely unreliable for the purposes of informing cost allowances for the present price reset.

1.2 Brief overview of the AER's results

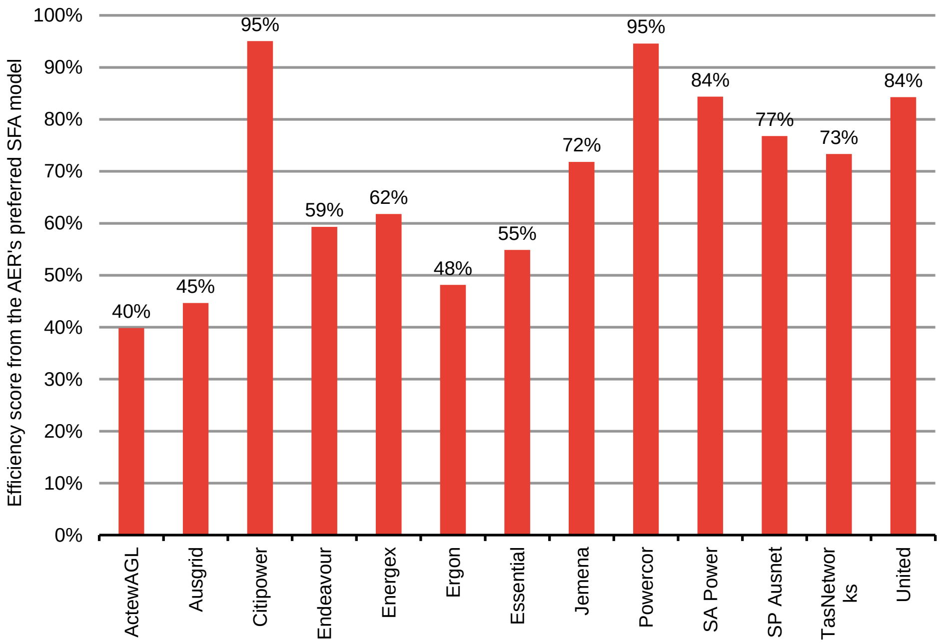
In our report to Networks NSW, we argued that EI's analysis had failed to take into account the vast heterogeneity of circumstance, and hence cost to serve, between DNSPs. By failing to take proper account of these differences in circumstance, EI's efficiency estimates did not capture solely differences in managerial performance. EI's measures instead conflated managerial efficiency with the effect of uncontrolled for differences in circumstance, i.e. latent heterogeneity. This led EI and the AER to conclude erroneously that many of the DNSPs were materially inefficient.

2 Frontier Economics, *Review of the AER's econometric benchmarking models and their application in the draft determinations for Networks NSW*, January 2015.

As we also explained in our report, adding data from Ontario and New Zealand did not help to solve this problem. We found evidence to show that the cost structures of DNSPs in Ontario and New Zealand are significantly different to those in Australia, arising as a consequence of the need for those companies to address different operational challenges from those found in Australia. In short, it was invalid to have pooled the data from these three regions together.

The AER identified a very large spread in performance across the businesses in its sample. As shown in Figure 3 below, the AER's efficiency scores for the Australian DNSPs ranged from 40% to 95%.

Figure 3. AER's efficiency scores



Source: Frontier figure created from EI's efficiency scores

An inspection of the results, coupled with knowledge of the service regions operated by each DNSPs, will immediately points to potentially important costs drivers that have not been captured. For example, the six networks identified by the AER to be the least efficiency, including Ergon, are those that own significant quantities of high voltage assets which are more costly to maintain. The seven networks identified to be the most efficient by the AER do not own any of these high voltage assets. Since high voltage network is typically only economic when power is being transmitted over longer distances, this immediately suggests that the AER/EI model fails to control for the challenges of serving large and potentially sparsely populated service areas.

For all of the foregoing reasons, which we expanded upon at length in our report for Networks NSW, we consider that the efficiency scores generated by EI should not be used to inform regulatory determinations. In our view, the AER has concluded erroneously that many of the Australian DNSPs, including Ergon, are significantly inefficient because it has failed to account for the genuine heterogeneity of circumstances across the different businesses.

We concluded that the AER should discard its analysis based on the international data, and replace it with less ambitious and more pragmatic analysis rooted in more relevant comparisons based on a comparison of the Australian DNSPs only.

1.3 Purpose and structure of this report

This report builds on the work already completed for Networks NSW. The report focuses on demonstrating further and more specifically the vast heterogeneity in circumstance across the Australian DNSPs, with respect to network design, population dispersion, weather and terrain. All of these are that are materially distorting the AER's benchmarking results.

We focus in particular on the circumstances affecting Ergon. The AER's analysis implies that Ergon Energy (Ergon) is the third least efficient of all the Australian DNSPs (ahead only of Ausgrid and ActewAGL), with an efficiency score of 48%. In our view, EI's findings are driven by a failure to account for the very special circumstances in which Ergon operates.

The remainder of this report is structured as follows.

- In **Section 2** we show that Ergon's operating circumstances are manifestly different from most other DNSPs in Australia. Ergon's unique circumstances mean that its costs cannot be compared easily with most other DNSPs in Australia. The source of these differences include the characteristics of Ergon's network, which has been engineered to serve a vast and sparsely-populated region (Ergon serves over 97% of Queensland by land area), and the more extreme environmental conditions faced by networks in Queensland.
- In **Section 3** we demonstrate the impact of accounting for some of the latent heterogeneity between DNSPs directly, using EI's existing modelling framework (notwithstanding the weaknesses that remain in the model even after including additional variables in the EI model). Doing so narrows the efficiency gap identified by EI considerably.

- In **Section 4** we show the effect of accounting for additional special factors by applying a two-stage approach, which has been suggested by, amongst others, Coelli et al (2005).[3] Doing so narrows the efficiency gap even further.
- In **Section 5** we explain how, in line with the approach taken by some regulators in Europe, unaddressed special factors may be accounted for separately, outside a formal statistical benchmarking model.

3 Coelli, T. J., D.S.P. Rao, C. J. O'Donnell and G.E. Battese (2005), *An Introduction to Efficiency and Productivity Analysis (2nd ed)*, Springer.

2 Ergon's circumstances are unique

Ergon has provided a number of submissions to the AER explaining the ways in which its operating circumstances differ significantly from most other DNSPs in Australia. Many of these differences are easily demonstrable using benchmarking RIN data collected by the AER. Whilst Ergon has set out at length evidence on how its circumstances are unique, the key differences between Ergon and other DNSPs bear repeating here. That is because clear recognition of the circumstances Ergon faces when serving customers, and how these differ from those faced by other DNSPs, must form an integral part of the benchmarking analysis the AER undertakes when setting cost allowances for Ergon.

As we explained in our report to Networks NSW, failure to account for the large differences between networks will provide a very distorted picture of relative efficiencies by identifying genuine variation in operating conditions as managerial inefficiency. Hence, benchmarking analysis that does not account properly for heterogeneity of circumstances will tend to advantage systematically those networks that have particularly favourable circumstances, and disadvantage those networks that have particularly unfavourable circumstances. As the analysis in this section shows, Ergon is a network facing a particularly onerous operating environment.

In this section we show that Ergon's scale of operations is vast, relative to its customer base and the energy demand from those customers. As a result, Ergon must contend with extreme network sparsity, and the attendant realities of serving customers that are distributed widely through by far the largest service area in Australia. The pattern of costs incurred by Ergon in maintaining such a network, and providing an acceptable level of quality, would be expected to look very different from most other networks in Australia, which enjoy a much denser distribution of customers.

We also show in this section that Ergon operates in a part of Australia that is vulnerable to very extreme climate and environmental conditions. These conditions may be expected to affect Ergon's costs of operating and maintaining its network. Further, these environmental factors differ significantly from those faced by many other DNSPs in Australia. As such, the AER's benchmarking analysis should also take account of these environmental factors. However, the benchmarking analysis that the AER has produced to date has failed to do so.

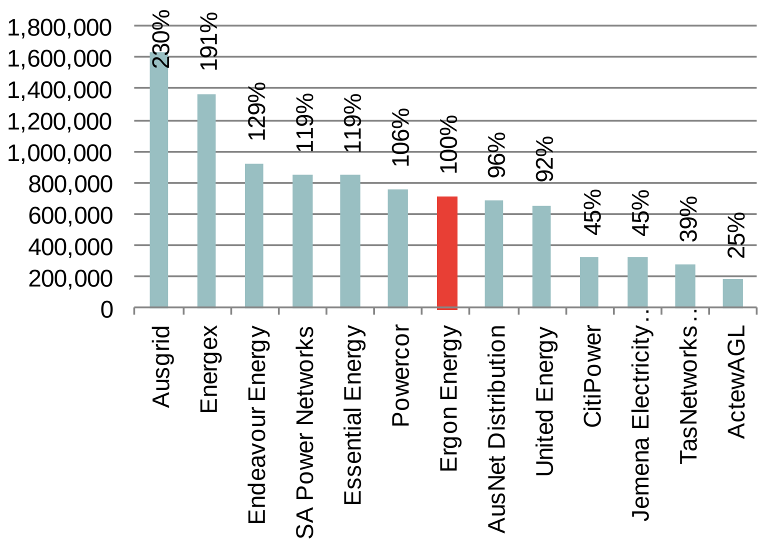
The various factors we survey in this section are not exhaustive because we have been limited by the time available to develop this report. Further work (and greater engagement between the AER and Ergon) is required in order to achieve a more comprehensive assessment of the factors that make Ergon's circumstances unique and how those factors may be quantified in future work.

2.1 Network characteristics

2.1.1 Scale

The benchmarking RIN data collected by the AER shows that in 2013 Ergon had over 710,000 customers. As Figure 4 shows, the size of this customer base is not dissimilar from several other DNSPs including Endeavour Energy, SA Power Networks, Essential Energy, Powercor, AusNet Distribution and United Energy. Energex's customer base is nearly twice as large as Ergon's and Ausgrid's customer base is considerably more than twice that of Ergon's.

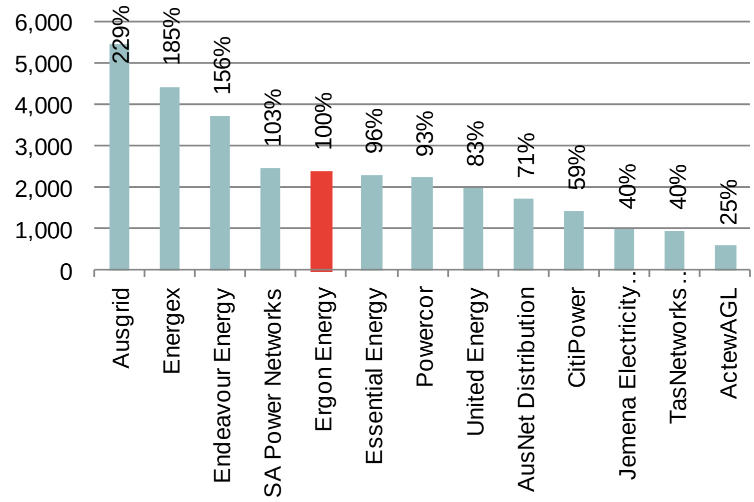
Figure 4: Customer numbers



Source: 2013 AER benchmarking RIN data. Notes: Percentages calculated with respect to Ergon's values.

As Figure 5 shows, the maximum demand in relation to Ergon's network is similar to that of a number of other networks including SA Power Networks, Essential Energy, Powercor and United Energy. It is considerably lower than the maximum demand in relation to Ausgrid's, Energex's and Endeavour Energy's networks.

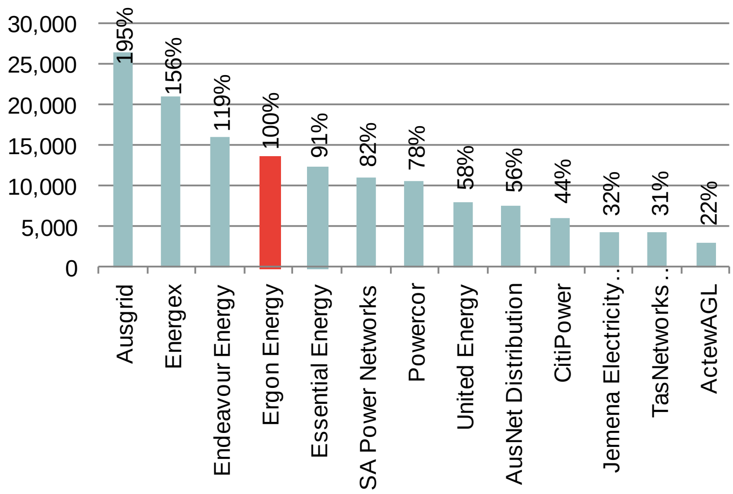
Figure 5: Maximum demand (MW)



Source: 2013 AER benchmarking RIN data. Notes: Percentages calculated with respect to Ergon's values.

Figure 6 shows that Ergon's output, in terms of delivered energy, is the fourth largest amongst the 13 DNSPs in the NEM.[4] This may be driven in part by the fact that Queensland experiences the hottest year-round temperatures of the NEM states (see section 2.2). Nevertheless, the amount of energy delivered by Ergon is significantly less than is delivered by Ausgrid and Energex.

Figure 6: Energy delivered (GWh)

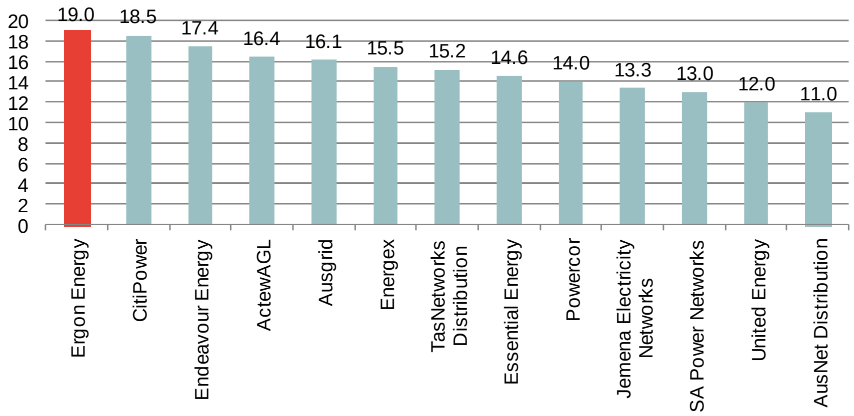


Source: 2013 AER benchmarking RIN data. Notes: Percentages calculated with respect to Ergon's values.

4 The RIN data show that the energy delivered by Ergon, from year to year, between 2006 and 2013, has been relatively stable.

Figure 7 shows that Ergon's customers are particularly energy-intensive; Ergon delivers more energy per customer than any other DNSP in the NEM.

Figure 7: Energy delivered per customer (MWh per customer)

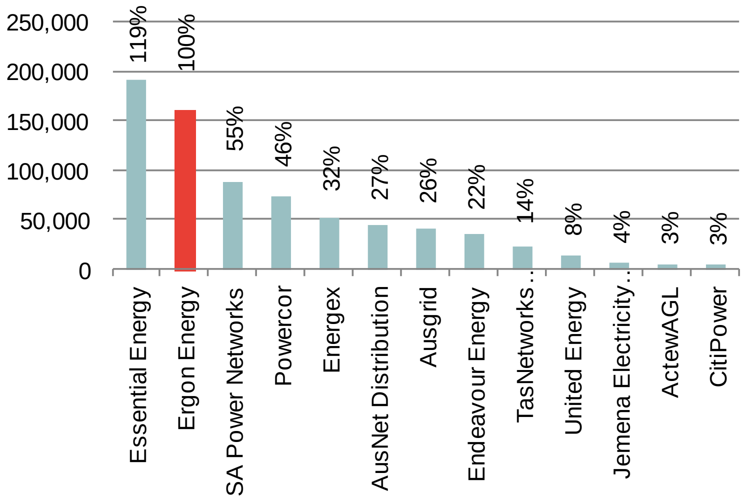


Source: 2013 AER benchmarking RIN data.

Notwithstanding Ergon's relatively modest customer base and energy demand, the scale of its operations is massive. This is driven by the vast geographical area it must cover in order to serve its customer base. For instance, as Figure 8 shows, Ergon's circuit length is surpassed only by Essential Energy's. The benchmarking analysis produced by the AER in its Draft Decisions for the NSW/ACT networks identifies CitiPower, Powercor, SA Power Networks and United Energy as the four most efficient DNSPs (in that order) in Australia. Ergon's circuit length is:

- more than 37 times greater than CitiPower's;
- more than twice as long as Powercor's;
- nearly twice as long as SA Power Network's; and
- approximately 12.5 times greater than United Energy's.

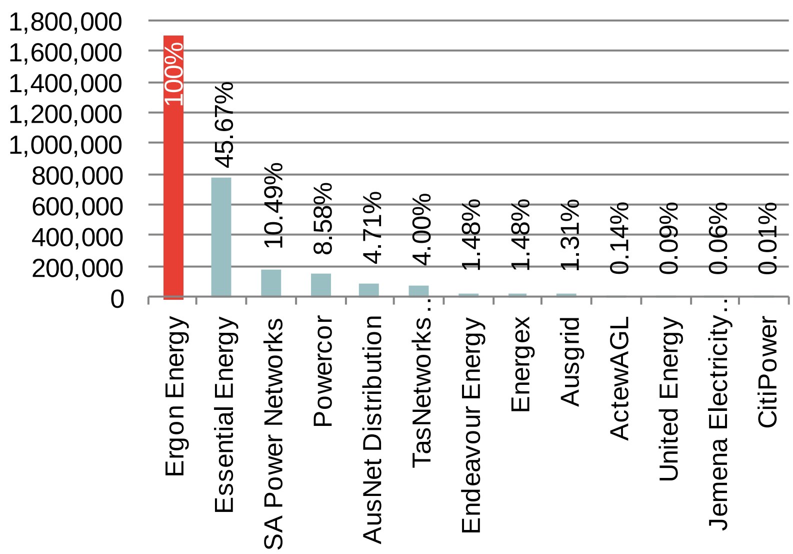
Figure 8: Circuit length (kms)



Source: 2013 AER benchmarking RIN data. Notes: Percentages calculated with respect to Ergon's values.

Figure 9 makes clear why Ergon has such a large physical network: it serves a geographical area that is by far the largest in Australia.

Figure 9: Service area (sqkms)



Source: Ergon. Notes: Percentages calculated with respect to Ergon's values.

Essential Energy, which covers the second largest geography in NEM region, has a service region that is less than half that of Ergon's. Ergon's service area (1,698,100 km^2) is nearly 11,000 times larger than CitiPower's (157 km^2).

To put the scale of Ergon's service area into perspective, we noted in our report to Networks NSW that Ergon serves an area significantly greater than the land area of France (547,700 km²), the UK (241,900 km²) and Spain (498,800 km²) combined, and nearly twice the land area of Ontario (917,741 km²).[5] These statistics alone ought to give the AER pause to consider whether it is sensible to treat networks of such vastly different scales as if their characteristics may be captured by a small set of common explanatory factors. In our view the benchmarking analysis that the AER applied in its Draft Decisions for the NSW/ACT networks fails to control adequately for important differences that arise as a result of differences in service area and customer density.

As a consequence of such a large service area, Ergon has had to engineer its network to contend with extreme distances, remoteness and inaccessibility when undertaking inspections and maintenance of its network, and when dealing with faults and emergencies. This will result in engineering solutions – and hence cost structures – quite different to those adopted by DNSPs serving much smaller and more densely populated areas.

Subtransmission assets

Figure 10 shows that Ergon has over 60% more length of circuit above 66kV than any other DNSP regulated by the AER. According to the benchmarking RIN data, seven DNSPs (CitiPower, Jemena Electricity Networks, Powercor, SA Power Networks, AusNet Distribution, TasNetworks and United Energy) have no assets in excess of 66kV.[6]

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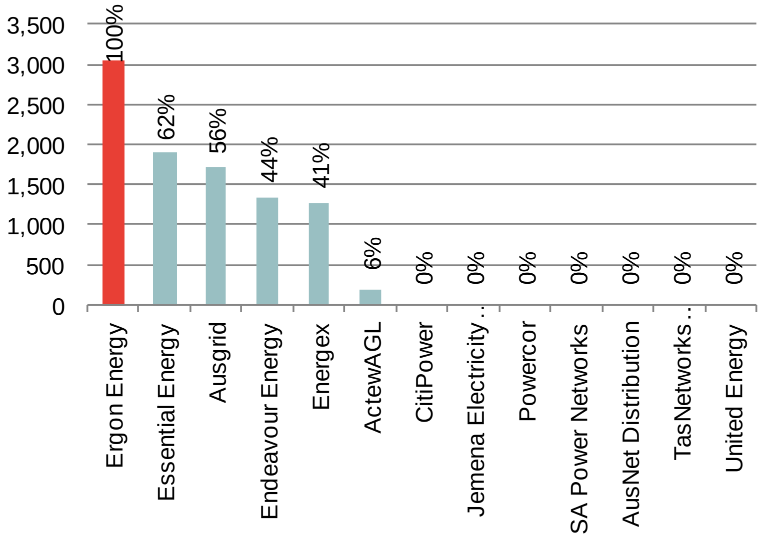
5 Land area values for France, New Zealand, Spain and UK were obtained from the World Bank World Development Indicators (Table 3.1); land area data for Ontario were obtained from Statistics Canada. 'Land area' is defined by the World Bank as "…a country's total area, excluding area under inland water bodies, national claims to continental shelf, and exclusive economic zones. In most cases the definition of inland water bodies includes major rivers and lakes."

6 The present day ownership of subtransmission assets by distribution networks in different States is partly a legacy of different level policy decisions taken when State-level electricity markets were restructured and reformed in the 1990s. For instance, in NSW, following the market reforms, the issue of whether 132kV assets should be owned by Transgrid (the transmission network operator) or the various distributors was hotly contested in a number of market reviews. The outcomes of those reviews meant that Transgrid took ownership of some 132kV assets, whilst the distributors took ownership of other subtransmission assets. (See, for example: Distribution Review Group, Electricity Distribution Structure Review, August 1995.) In other States, such as Victoria, the ownership of subtransmission assets was less controversial. When the Victorian Electricity Supply Industry was vertically separated during reforms in the early 1990s, five separate distribution networks, and one transmission operator, were established. Network separation occurred according to network functions, and distribution activities were defined as those involving 66kV assets and below (see, for example: Office of the State Owned Enterprises Department of the Treasury, Reforming Victoria's Electricity Industry, December 1994). During these reforms, the five distribution networks were endowed with 66kV assets and below, while the transmission operator took ownership of assets of higher voltage.

Figure 10: Circuit length over 66kV (kms)



Source: 2013 AER benchmarking RIN data. Notes: Percentages calculated with respect to Ergon's values.

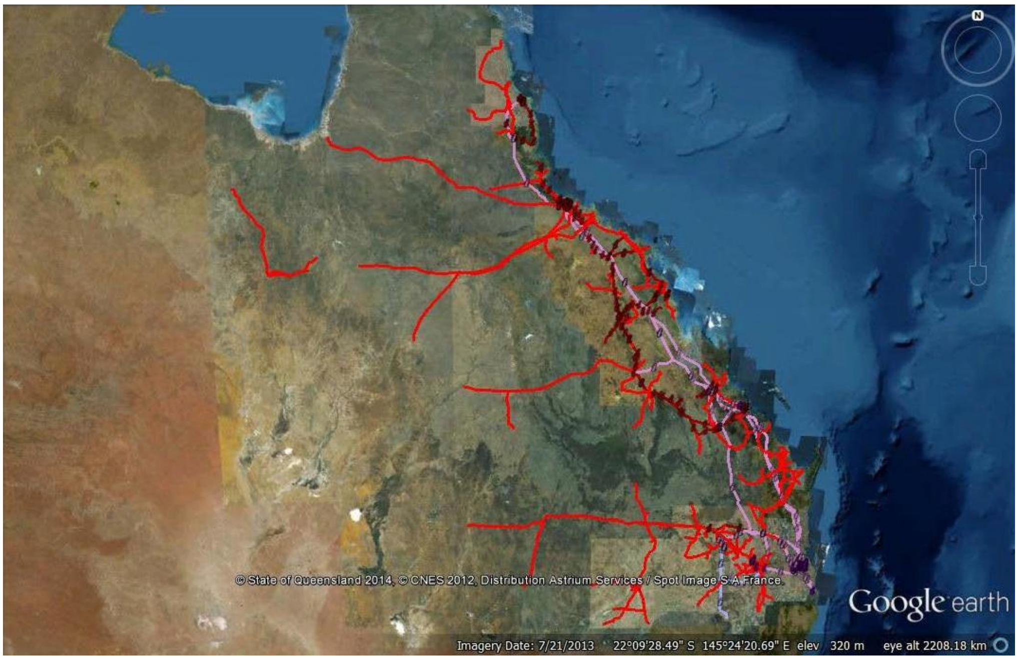
In its submission to the AER entitled *How Ergon Energy Compares*, Ergon explained that the need for such significant investment in high voltage lines is:[7]

> …due to the significant potential for voltage drop over the vast distances to be covered, and the boundaries of the Powerlink Transmission network.

Figure 11 reproduces an exhibit in Ergon's submission to the AER, which shows an aerial view of Ergon's subtransmission feeders (represented in red) and Powerlink's transmission network (represented in mauve). This map shows clearly that Powerlink's network occupies a narrow corridor that follows the eastern coastline of Queensland and, as such, does not supply most of Ergon's service area. As a result, Ergon has had to invest in a significant number of high voltage lines to supply its customers to the west of Powerlink's network.

7 Ergon, *How Ergon Energy Compares*, October 2014, p.4.

Figure 11: Coverage of Ergon's subtransmission network and Powerlink's transmission network



Source: Ergon, How Ergon Energy Compares, October 2014, p.5.

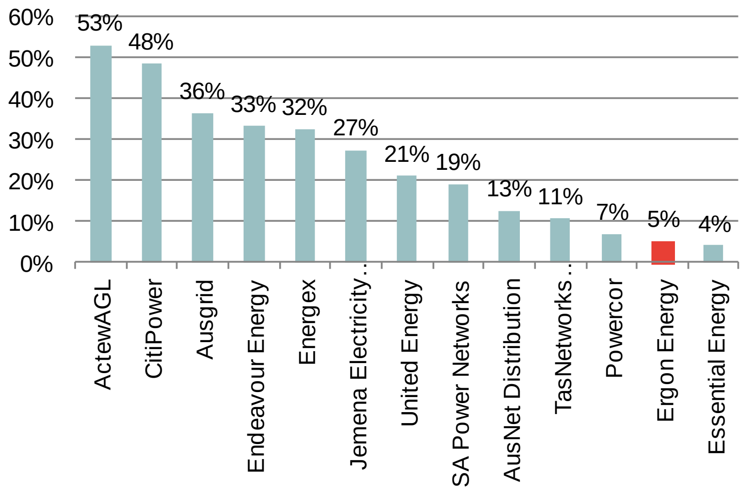
It is apparent that Ergon has had to engineer its network in this way in response to exogenous factors, namely the coverage of the transmission network and its very large service area. This gives rise to three implications.

Firstly, Ergon is required to provide an additional service – substransmission – that other DNSPs operating smaller regions, or with operations closer to the transmission operator's network, do not need to provide. (Very few customers, if any, will be served directly by these subtransmission assets as these are feeders from the transmission backbone.) This will give rise to direct costs associated solely with these assets.

Secondly, the quantity of high voltage lines may be a useful indicator of spatial differences more generally between networks. In addition to needing to provide a subtransmission network, affected DNSPs are likely to face additional challenges operating large, sparse regions that go far beyond the direct cost of providing the subtransmission assets themselves.

Thirdly, as noted by Ergon in its submission to the AER, the large distances that need to be covered restrict the use of undergrounding for significant. This is borne out by the data in Figure 10, which shows that the DNSPs with the largest service areas, Ergon and Essential, also have the smallest proportion of network underground.

Figure 12: Underground cables as a proportion of total circuit length



Source: 2013 AER benchmarking RIN data.

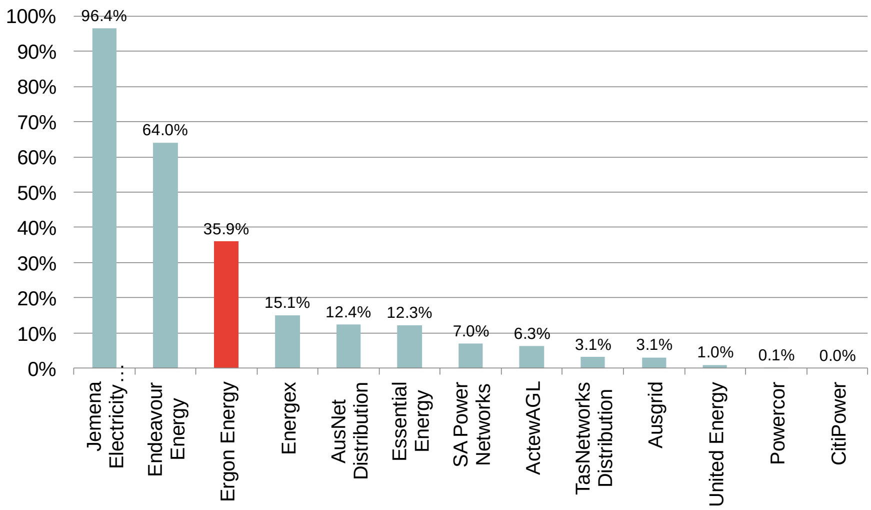
Undergrounding of assets typically means high upfront capital costs, but then relatively low maintenance costs thereafter. The need to install overhead lines is likely to drive higher maintenance workloads due to exposure to environmental factors (e.g. storm damage, humidity, temperature, etc.).

All of these factors can be expected to increase opex for justifiable reasons relative to more normal operating circumstances.

Remoteness and accessibility

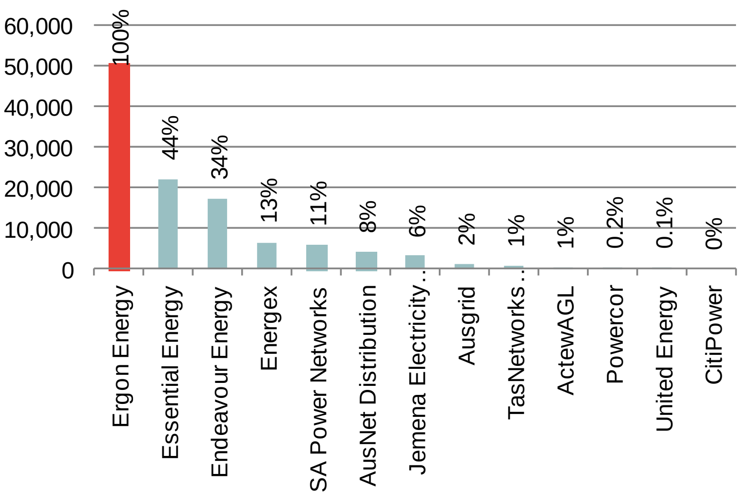
An issue related to the large geographical region that Ergon must serve is the remoteness and poor accessibility to large sections of this region. Figure 13 shows that over a third of Ergon's route line length does not have standard vehicle access. Although in proportional terms this is not as high as for other DNSPs, such as Jemena Electricity Distribution and Endeavour Energy, in absolute terms Ergon has more than twice as much non-standard access route length as any other DNSP (see Figure 14).

Figure 13: Distribution route line length that does not have standard vehicle access as a proportion of total route line length



Source: 2013 AER benchmarking RIN data.

Figure 14: Distribution route line length that does not have standard vehicle access (kms)



Source: 2013 AER benchmarking RIN data. Notes: Percentages calculated with respect to Ergon's values.

We understand from discussions with Ergon that the extreme distances, remoteness and ruggedness of parts of its network impose costs that do not arise (or are less significant) for networks covering smaller service areas. Examples of these costs include the following:[8]

8 See also Ergon's response (dated 17 December 2014) to the AER's information request in relation to Ergon's special environment operating factors.

- Large tracts of land within Ergon's service area become impassable following heavy rain. (This is particularly so in areas with poor standard vehicle access.) In these circumstances, it becomes necessary to use specialised all-terrain (e.g. caterpillar-track) vehicles, helicopters and fixed wing aircraft to access network assets in those regions. Even in instances without poor weather, certain regions are so remote or rugged that the most feasible way to gain access for inspections and repair is via helicopter. Specialised transport of this kind is much more expensive than the use of standard vehicles for inspections, maintenance and repair.
- Distances between depots are often so large that staff conducting inspections and maintenance require overnight accommodation. Extensive travel also results in additional costs associated with meals for personnel, travel costs, and Living Away from Home Allowances. These additional costs may be largely avoided by DNSPs that serve less remote regions.
- In many instances, given the remoteness of sites, it is necessary not only to transport personnel, but also equipment (e.g. for vegetation management, replacement parts and equipment, specialised tools). Equipment transfer adds to transportation costs. DNSPs with smaller service areas typically incur fewer of these costs.
- All customers, including those living in remote areas, expect that their service needs will be met in a timely fashion. Customers living in remote communities particularly depend on power supplies to maintain communication, and disruptions to power supply can pose safety concerns. In order to meet the particular needs of these communities, Ergon may need to employ more expensive options for transporting workers and equipment. It may also be necessary to maintain more service depots per unit of service area than would be required in more densely populated regions, in order to be able reach customers and key network assets in a timely way.
- Telecommunications infrastructure in remote locations within Ergon's service area is often very sparse because it is uneconomic for telecommunications providers to offer service in these very remote regions. In such areas, Ergon has to provide and maintain its own communications infrastructure. This infrastructure is required not only for remote fault detection, switching and signalling, but also to meet occupational health and safety (OH&S) regulations (e.g. to ensure communication with staff working in remote and potentially dangerous terrain).

Networks affected by these factors will therefore face increased costs in constructing, operating and maintaining a given length of network and/or associated other assets such as transformers and switch gear.

2.1.2 Density

The analysis in the previous section suggests that an important source of heterogeneity between DNSPs is density. Network density can significantly alter maintenance and asset management costs (e.g. inspections, fault repair), as well as the costs associated with connecting and serving new customers. For instance, as noted above, for very rural, rugged and sparse networks, such as Ergon's, it may be essential to perform aerial (as opposed to on-the-ground) inspections, which can alter inspection costs significantly. Repair and maintenance work may be considerably more expensive than for denser networks (for instance, due to longer distances to travel, and potentially the need to arrange overnight accommodation for workers). Low density networks are likely to need more assets in order to be able to serve a given number of customers. Unless these differences arising from differences in density are accounted for, the benchmarking analysis may be distorted significantly.

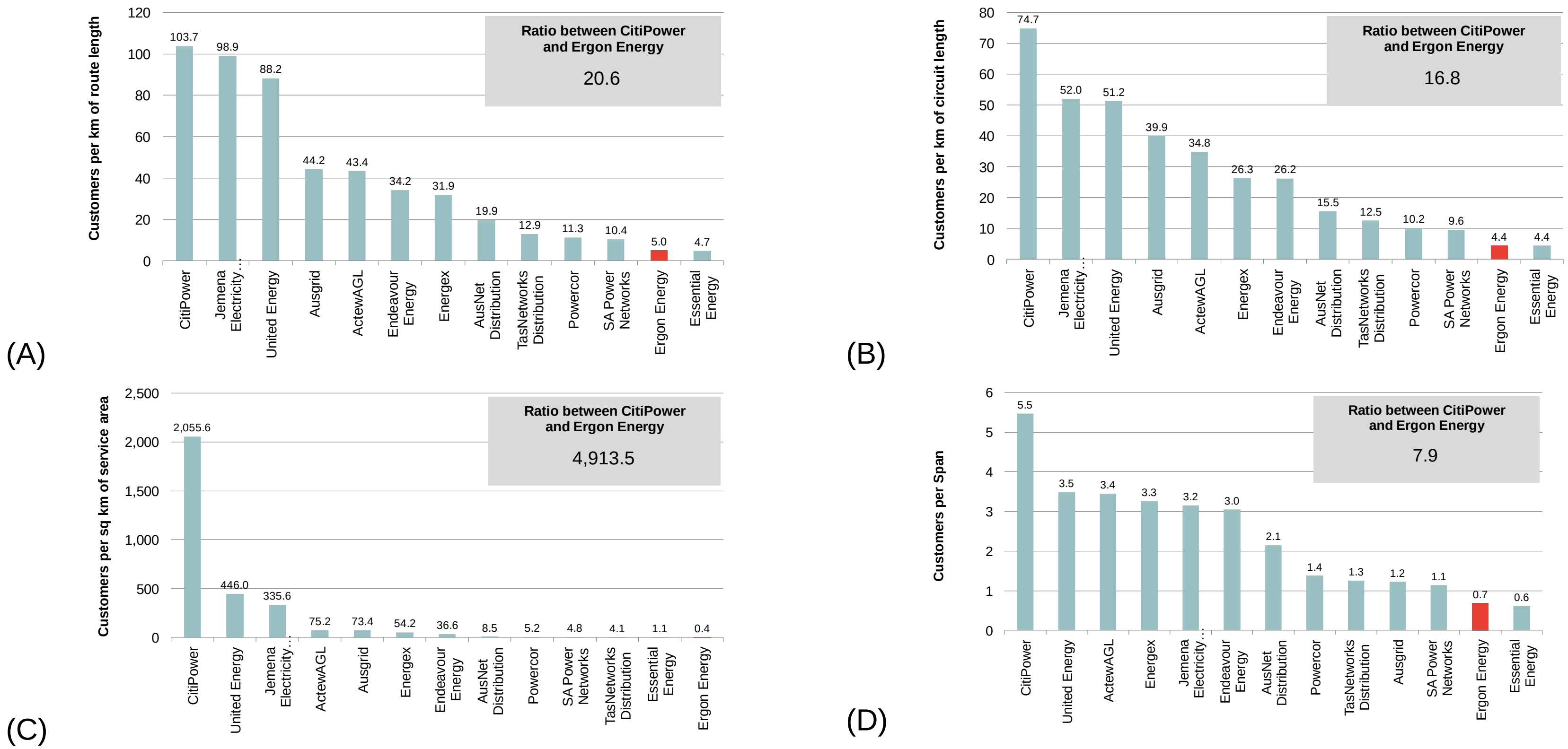
In Figure 15, we have analysed (using 2013 benchmarking RIN data) how dense the DNSPs' networks are using four fairly standard measures of customer density:

- customers per km of route length;
- customers per km of circuit length;
- customers per sqkm of service area; and
- customers per span.

Under every one of these metrics, CitiPower is identified clearly as the densest network. Under all but one of these measures (i.e. the number of customers per unit of service area) Ergon is identified as the second-most sparse network (surpassed only by Essential Energy). The differences in the densities of CitiPower's and Ergon's networks are very, very large. In particular:

- CitiPower has nearly 104 customers per km of route length, whereas Ergon has nearly 21 times fewer (i.e. five) customers per km of route length.
- CitiPower has almost 75 customers per km of circuit length, whereas Ergon has nearly 17 times fewer (i.e. 4.4) customers per km of circuit length.
- CitiPower serves, on average over 2,000 customers km^2 of service area (which comprises mostly of inner city Melbourne – a very dense, urbanised area). By contrast, Ergon serves on average one customer every 2.4 km^2.
- Finally, CitiPower has roughly 5.5 customers per span, whereas Ergon has nearly eight times fewer (i.e. 0.7) customers per span.

Figure 15: Measures of customer density – (A) Customers per km of route length; (B) Customers per km of circuit length; (C) Customers per square km of service area; (D) Customers per span



Source: 2013 AER benchmarking RIN data; Ergon; Frontier analysis.

Table 2: Comparison of AER's DNSP efficiency rankings and various indicators of network characteristics

DNSP	AER efficiency rank	Customers per km route length	Route length (km)	Customers per km^2 of service area	Service area (km^2)	Line length above 66kV (km)
CitiPower	1	104	4,318	2,056	157	0
Powercor	2	11	73,889	5	145,651	0
SA Power Networks	3	10	87,882	5	178,200	0
United Energy	4	88	12,835	446	1,472	0
AusNet Distribution	5	20	43,822	9	80,000	0
TasNetworks Distribution	6	13	22,336	4	68,000	0
Jemena Electricity Networks	7	99	6,135	336	950	0
Energex	8	32	51,781	54	25,064	1,266
Endeavour Energy	9	34	35,029	37	25,120	1,341
Essential Energy	10	5	191,107	1	775,520	1,896
Ergon Energy	11	5	160,110	0	1,698,100	3,059
Ausgrid	12	44	40,964	73	22,275	1,715
ActewAGL	13	43	5,088	75	2,358	192

Source: EI benchmarking analysis on behalf of AER, benchmarking RIN data, Frontier calculations

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It is clear from Figure 15 that Ergon's customer density is very different not just to the networks that the AER identifies in its NSW/ACT Draft Decisions as the most efficient network, but Ergon appears to be an outlier against most DNSPs in the sample. The DNSP with most comparable density to Ergon is Essential Energy.[9] It is therefore not surprising that the AER's benchmarking analysis in its Draft Decisions for NSW/ACT finds Essential Energy to be the fourth least efficient DNSP, and Ergon to be the third least efficient network.

Table 2 above compares the efficiency rankings produced by EI's Stochastic Frontier Analysis (SFA) model (which the AER relied on in its Draft Decisions for the NSW/ACT networks) against a number of indicators of network characteristics that are likely to be important determinants of operating and maintenance costs (given the preceding discussion). As we have explained above, there is significant variation in these indicators (e.g. measures of customer density and investment in high voltage lines). If the AER had taken account of these indicators of network characteristics properly, there should be no clear relationship between the efficiency rankings and the network characteristics indicators presented in Table 2 because these indicators would then not contribute much further information to the rankings.

By contrast, a fairly clear pattern is discernible. With the exception of two DNSPs (Ausgrid and ActewAGL), the EI's model tends to favour those networks with the highest customer density as being the most efficient. In addition, those networks that have the need to invest in high voltage lines tend to fare worst in the EI's model. In this respect, there appears to be a clear dividing line: only the networks in Queensland, NSW and ACT have invested in assets in excess of 66kV and these networks are identified by EI's model as the least efficient networks; the networks in Victoria, South Australia and Tasmania have not invested in any assets in excess of 66kV and are generally found by EI to be the most efficient in the sample.

In our view, this is strongly suggestive that EI/AER have failed to account for some important network characteristics, which relate to having to serve relatively sparse and remote regions of Australia. This, in turn, appears to have distorted the AER's benchmarking analysis, and has led the AER to conclude mistakenly that some networks are significantly less efficient than they actually are. In section 3 we test this proposition empirically.

9 SA Power Networks, which also serves a large rural region, is on three of the measures presented in Figure 15, approximately twice as dense as Ergon, in part because it also serves Adelaide and all the towns in South Australia.

2.2 Environmental conditions

In addition to the rather unique spatial characteristics of its network, Ergon also faces some unusual environmental (weather-related) factors that make its operating circumstances fairly uniquely onerous. In recognition of these factors, Ergon has to engineer its network to make it more resilient to worse conditions than most DNSPs in Australia experience, exacerbating the factors already identified above.

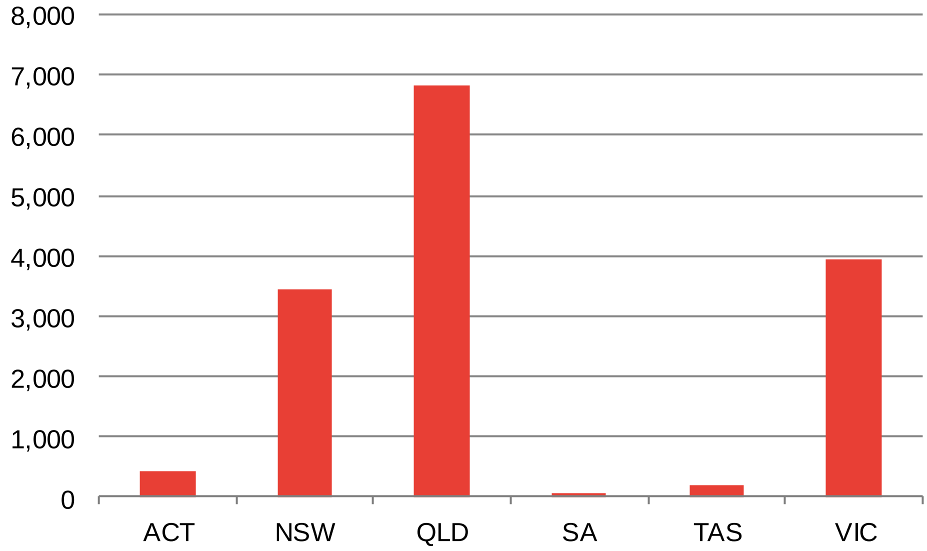
Data on these environmental factors are not available directly from the benchmarking RIN data collected by the AER. However, the benchmarking RINs do require networks to report the identification numbers and postcode details of weather stations within their service areas. This information allows detailed climate/weather data obtained from the Australian Bureau of Meteorology (BOM) to be analysed at the DNSP level. In this section we present such an analysis. We also present other, more aggregated data from the BOM, and other independent sources, that demonstrate that the environmental conditions that Ergon operates under are different those faced by most other DNSPs regulated by the AER.

2.2.1 Natural disasters and extreme weather conditions

Queensland experiences very severe and frequent natural disasters that cause major damage and disruption. As Ergon serves over 97% of Queensland, it bears the vast majority of the costs associated with damage and disruption to the electricity distribution infrastructure in the State. These costs arise as a result of emergencies and fault management and restoration of power following failures and outages after natural disaster events.

Figure 16 shows that the total value of insurance losses in Queensland, arising from natural disasters between 2000 and 2014, has far exceeded the losses experienced in any other State within the NEM region (i.e. nearly twice those in NSW and over 70% more than those in Victoria). According to data from the Insurance Council of Australia, one single event, cyclone Yasi, caused over 40% of the losses (i.e. $1.41 billion) experienced by the whole State of NSW over the entire 15 year period analysed in Figure 16. As Ergon has noted to the AER in a number of submissions, cyclone Yasi imposed very large operating and capital costs on Ergon.

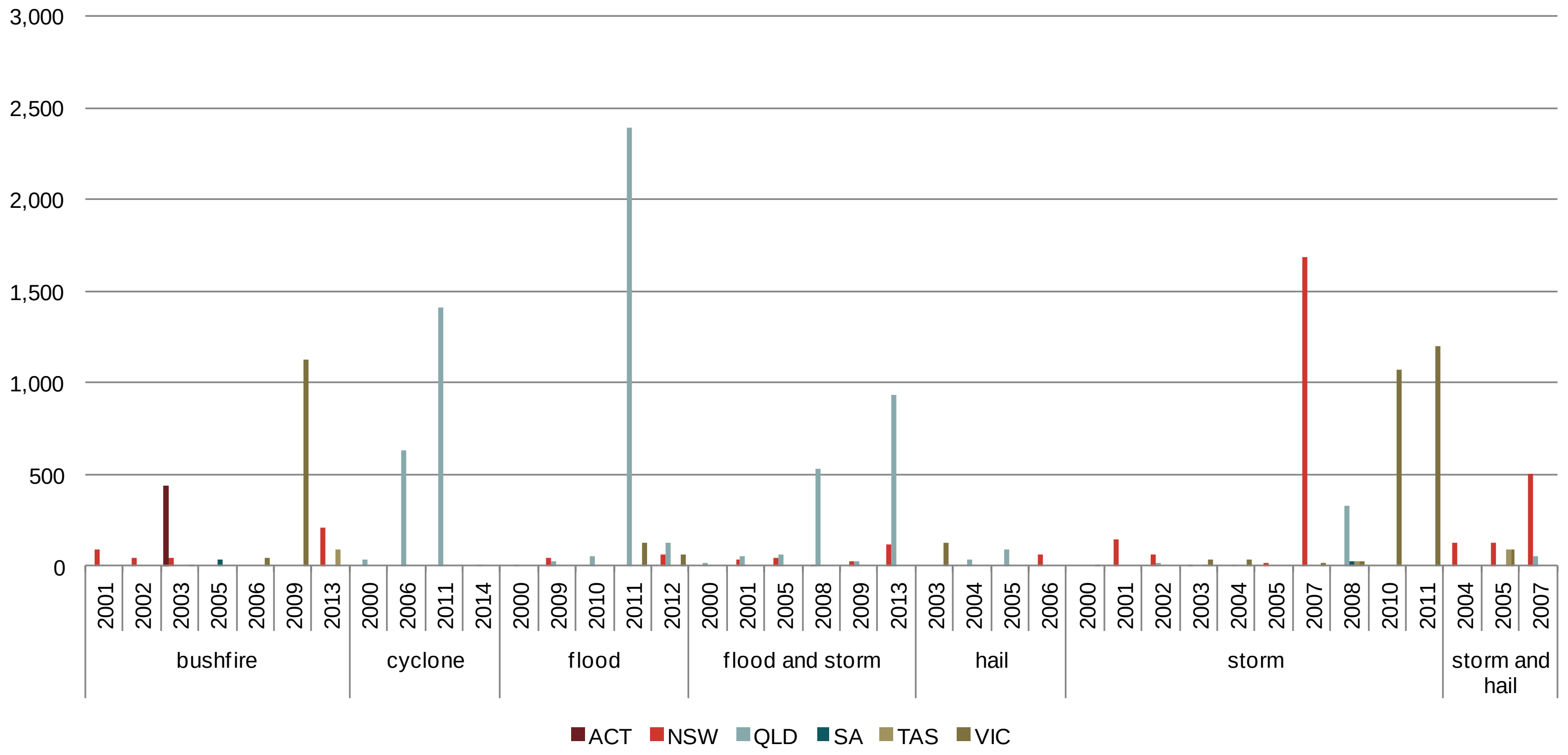
Figure 16: Total value of insurance losses arising from natural disasters, 2000 to 2014 ($millions, real 2011 values)



Source: Raw data on losses obtained from the Insurance Council of Australia; Frontier calculations. Note: Some events represented in these data affected more than one State; in such instances losses were apportioned evenly between the affected States.

Figure 17 presents how these insurance losses were distributed over the period by event type. The data show that most of the losses in Queensland have arisen from severe cyclones, floods and storms; no other State appears to be affected as severely by these events as Queensland.

Figure 17: Total value of insurance losses arising from natural disasters, by event type, 2000 to 2014 ($millions, real 2011 values)



Source: Raw data on losses obtained from the Insurance Council of Australia; Frontier calculations. Note: For presentational reasons, losses due to 'Storm and tornado' events not shown on this chart; these losses totalled $38.7 million and affected only NSW.

The BOM's Severe Storms Archive records data on major weather events by event type. Table 3 presents summary statistics on severe storms between 2000 and 2014 involving tornados, hail, rain and wind, including indicators of the intensity of the events.

Table 3: Summary statistics of severe storm events in NEM States between 2000 and 2014

Severe storm event	Intensity indicator	Mean	Median	Quartile 1	Quartile 2	Quartile 3	Quartile 4	Number of events
Tornado	**Max speed (km/h)**	153.5	149.5	105.0	149.5	198.0	252.0	4
Hail	**Hail stone size (cm)**	4.7	4.0	2.2	4.0	6.6	18.0	47
Rain	**Intense precipitation amount (mm)**	87.9	57.1	30.9	57.1	114.3	731.0	412
Wind	**Max gust speed (km/h)**	76.1	71.5	50.3	71.5	95.8	250.0	86

Source: Bureau of Meteorology Severe Storms Archive; Frontier analysis

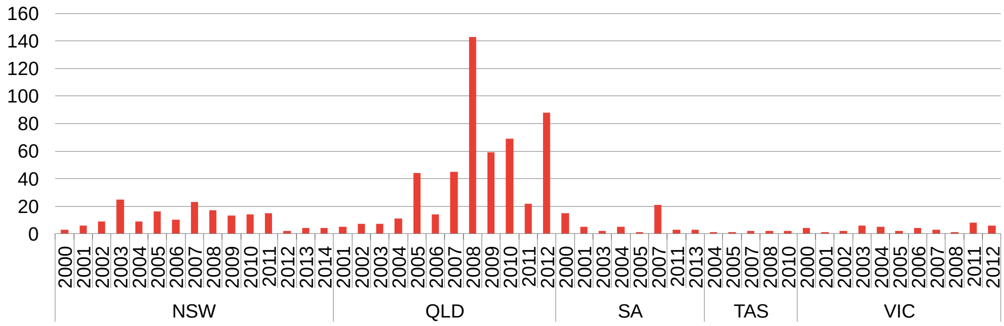
The data show, for instance, that the median value for:

- maximum wind speeds achieved by tornados during this period was nearly 150km/hour;
- hail stone size was 4cm;
- intense precipitation was nearly 88mm; and
- maximum wind gust speeds during severe storms was approximately 76km/hour.

Using these values, Figure 18 to Figure 21 presents the number of severe storm events by NEM State with above average intensities. As the chart shows:

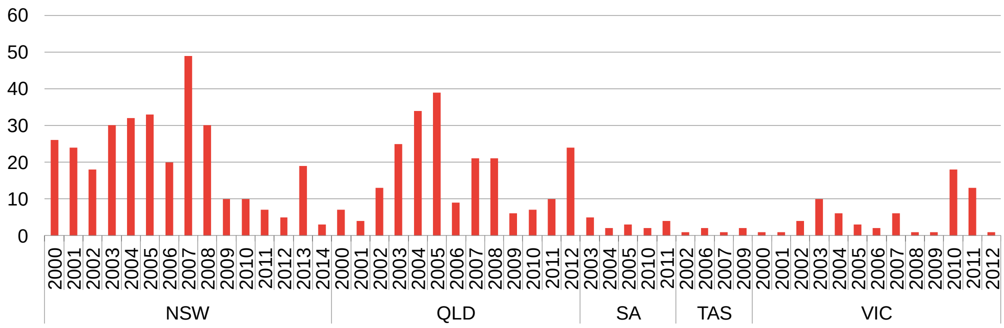
- no other State within the NEM region experiences more severe rainfall events than Queensland;
- NSW and Queensland have experienced a large number of severe hail events over the past 15 years; and
- Victoria is particularly vulnerable to storms with severe wind and tornados, although extreme wind is also problematic in Queensland.

Figure 18: Number of severe storm events in NEM States of above average rain intensity



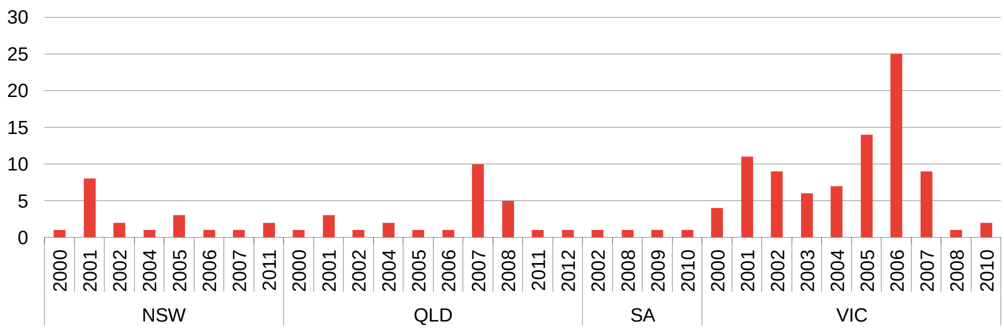
Source: Bureau of Meteorology Severe Storms Archive; Frontier analysis

Figure 19: Number of severe storm events in NEM States of above average hail intensity



Source: Bureau of Meteorology Severe Storms Archive; Frontier analysis

Figure 20: Number of severe storm events in NEM States of above average wind intensity



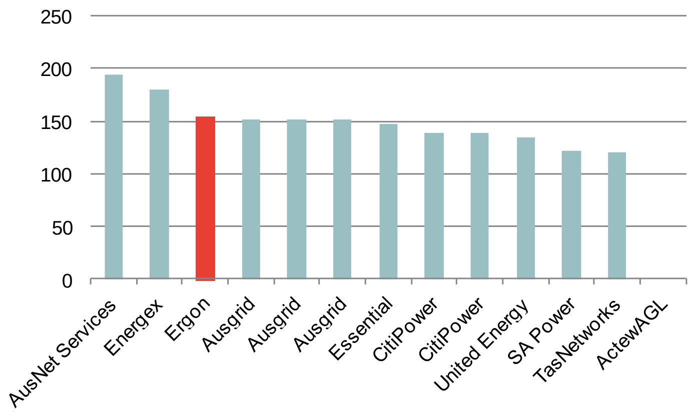
Source: Bureau of Meteorology Severe Storms Archive; Frontier analysis

Figure 21: Number of severe storm events in NEM States of above average tornado intensity

Source: Bureau of Meteorology Severe Storms Archive; Frontier analysis

Figure 22 plots the 90th percentile of maximum wind gust speed (over the years 1949 to 2014) experienced within each DNSP's service area. Figure 22 shows that next to AusNet Services, the two service areas of the two Queensland DNSPs, Energex and Ergon, experience the most extreme wind gusts.

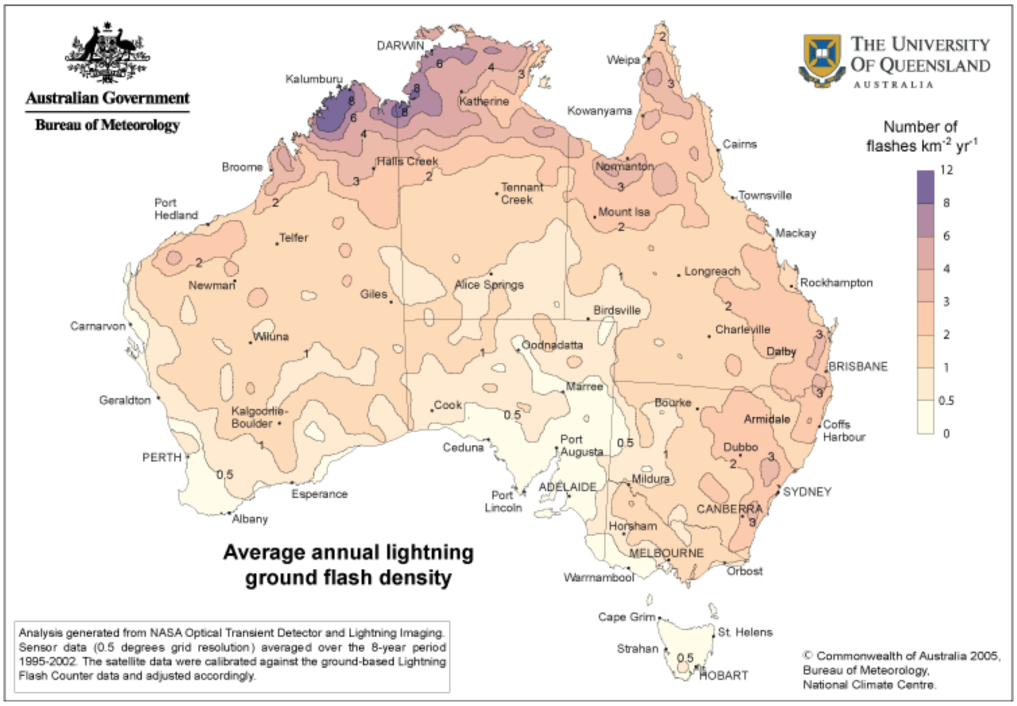
Figure 22: Maximum wind gust speed (km/h) by DNSP, 90th percentile, 1949 to 2014



Source: Bureau of Meteorology; AER benchmarking RIN data; Frontier analysis. Note: ActewAGL reported only two weather stations as falling within its service area; maximum wind gust speed data for these stations could not be readily obtained. Analysis is based on weather stations identified by DNSPs as being material.

Figure 23 plots the average cloud-to-ground lightning flash densities experienced in Australia. The map indicates that a high level of lightning activity is observed in the northern parts of Australia, and a decrease in total flash density occurs southward in central and southern parts of Australia. Of the NEM states, Queensland and NSW appear to experience the most lightning strikes. This is not surprising given the high storm activity experienced in these States. Ergon has submitted to the AER that lightning destroys poles by direct strikes, and also causes secondary damage by starting fires that consume other poles not struck directly.

Figure 23: Average cloud-to-ground lightning flash density, 1995 to 2002



Source: Bureau of Meteorology

We are advised by Ergon that major storm events result in increased forced maintenance costs, inspection costs, travel and accommodation costs and the bringing forward of renewals costs. In addition, because severe storm events occur seasonally, Ergon undertakes significant annual scheduled maintenance work before each storm season to mitigate the effects of storm damage. This may involve, for instance, inspections (including costly aerial inspections), reinforcement of parts of the network (including maintenance work on tracks and access routes), and vegetation management.

In its submission to the AER entitled *Forecast Expenditure Summary – Operating Costs*, Ergon notes that, historically, it has not insured its electricity network assets against major damage or loss caused by storms and cyclones because of a lack of available and efficiently priced insurance cover in the insurance markets. As a consequence, Ergon has either tried to recoup storm losses through pass-through items, or has absorbed the costs associated with these losses.

2.2.2 Cyclones

Cyclones occur seasonally (generally between December and March) in the northern regions of Australia. Cyclones affect Western Australia, the Northern Territory and New South Wales. However, the State most prone to cyclones is Queensland.

Table 4 presents the tropical cyclone category system.

Table 4: Tropical cyclone category system

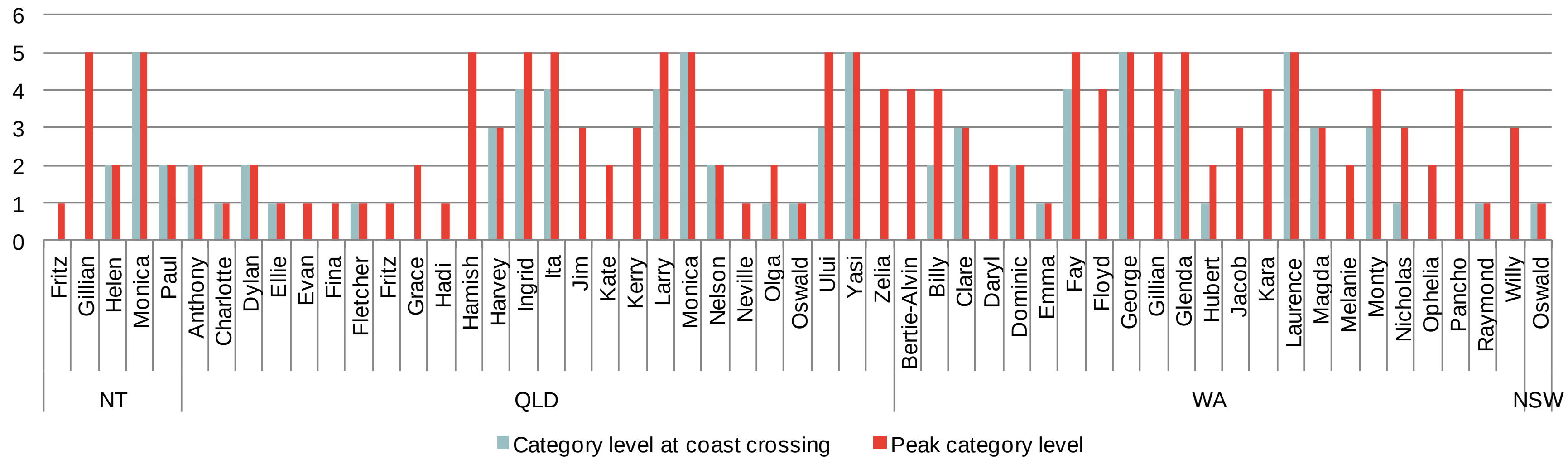
Category level	Definition
Category 1 **(Tropical cyclone)**	Negligible house damage. Damage to some crops, trees and caravans. Craft may drag moorings. A Category 1 cyclone's strongest winds are GALES with typical gusts over open flat land of 90 - 125 km/h.
Category 2 **(Tropical cyclone)**	Minor house damage. Significant damage to signs, trees and caravans. Heavy damage to some crops. Risk of power failure. Small craft may break moorings. A Category 2 cyclone's strongest winds are DESTRUCTIVE winds with typical gusts over open flat land of 125 - 164 km/h.
Category 3 **(Severe tropical cyclone)**	Some roof and structural damage. Some caravans destroyed. Power failures likely. A Category 3 cyclone's strongest winds are VERY DESTRUCTIVE winds with typical gusts over open flat land of 165 - 224 km/h.
Category 4 **(Severe tropical cyclone)**	Significant roofing loss and structural damage. Many caravans destroyed and blown away. Dangerous airborne debris. Widespread power failures. A Category 4 cyclone's strongest winds are VERY DESTRUCTIVE winds with typical gusts over open flat land of 225 - 279 km/h.
Category 5 **(Severe tropical cyclone)**	Extremely dangerous with widespread destruction. A Category 5 cyclone's strongest winds are VERY DESTRUCTIVE winds with typical gusts over open flat land of more than 280 km/h.

Source: Bureau of Meteorology

The table shows that significant damage, and risk of power failure, can occur even with Category 2 cyclones. Cyclones of Category 3 and higher are classified as 'very destructive', with power failures either likely or widespread.

Figure 24 shows that of the 51 tropical cyclones that have affected Australia over the past decade, over half, 26, have affected Queensland. (The only other Australian State to experience a similar number of cyclones over this period, 23, was Western Australia. However, the electricity networks in Western Australia are regulated by the AER or included in the AER's benchmarking analysis.) Of these, 10 cyclones were classified as Category 2 or higher when they made landfall.

Figure 24: Severity of cyclones that have affected Australia since 2004 (cyclone category level)



Source: Bureau of Meteorology Severe Storms Archive; Frontier analysis.

Notes:

1. *Over the period analysed, four tropical cyclones were recorded as having impacted more than one state. In these circumstances, for the purposes of this analysis, any cyclones that affected multiple states were assigned to all states affected.*
2. *All cyclones that were not identified as having made land fall, and all tropical lows, were excluded from this analysis.*

In recent times, the most destructive of the cyclones to have affected Queensland was severe tropical cyclone Yasi, which caused widespread damage to Queensland (see Box 1).

Box 1: Severe tropical cyclone Yasi, Queensland 2011

Cyclone Yasi developed as a tropical low north-west of Fiji on 29 January 2011. On 30 January, it was named Yasi by the Fiji Meteorological Service. On 2 February, it was upgraded to a Category 5 system and made landfall near Mission Beach (138 km south of Cairns) between midnight and 1 am (AEST) early on Thursday 3 February. It weakened to a tropical low near Mount Isa around 10 pm on 3 February.

In response to warnings about the expected severity of the cyclone, and possible storm surges, approximately 10,000 northern Queenslanders living in low-lying areas evacuated to more than 100 official evacuation centres. Significant numbers were accommodated in unofficial evacuation centres established by communities and church groups. Thousands of people left the area and sought refuge with family and friends.

Flights out of the region were fully booked. The hospital's 300 patients were evacuated to Brisbane and other regional hospitals by the Australian Defence Force, Royal Flying Doctor Service and other means of transportation. This was an unprecedented evacuation effort.

The eye of the cyclone passed over Dunk Island and Mission Beach between Innisfail and Townsville bringing significant winds, the highest estimated at 285 km per hour. Considerable damage occurred to the towns of Tully, Cardwell, Tully Heads, Innisfail, Ingham, Mission Beach, El Arish, Silkwood and Silky Oak and localities, however, the cyclone’s worst impact missed the major centres of Townsville and Cairns. Overall, approximately 1,000 people reported significant damage to their homes. Other impacts include power loss to more than 200,000 properties, cars found metres away from where they were left and boats piled on top of each other in some regions.

Rainfall totals for the 24 hour period to 9 am Thursday 3 February were 200-300 mm in the area between Cairns and Ayr, causing some flooding. A 5m tidal surge was observed at the storm tide gauge at Cardwell. Other sea inundation occurred between the beaches north of Cairns and Alva Beach, and there was some inundation in parts of the city of Townsville.

The Australian Bureau of Agriculture and Resource Economics and Sciences estimated the cyclone caused a $300 million loss to agricultural production in Queensland, particularly the banana and sugarcane sector.

The Federal Government processed more than $250 million worth of recovery grants in the first three weeks after the storm through Centrelink. Financial help was also available in the form of concessional loans for cyclone hit farmers up to $650,000.

There was one recorded death.

The Insurance Council of Australia estimated the preliminary 2011 damage at $1,412 million.

Source: Australian Emergency Management Knowledge Hub

It is important to note that the category level of a cyclone may not always be a good indication of the damage and disruption caused. For instance, tropical cyclone Oswald (2013) was a Category 1 cyclone when it crossed the Queensland coast. Nonetheless, it caused major damage due to strong winds and widespread flooding from coastal inundation and heavy rainfall. The Insurance Council of Australia estimates that Oswald caused $121 million of damage to NSW and $977 million of damage to Queensland.[10]

[10] Australian Emergency Management Knowledge Hub.

Apart from extreme wind damage, cyclones can also cause flooding due to heavy rain and storm surges in coastal areas. Cyclones Larry (2006), Ului (2010) and Yasi (2011) resulted in surge heights of 2.3m, 2.45m and 2.36m each.[11] Flooding can: cause damage to assets which then need ongoing maintenance work; make access to damaged parts of the network slow and difficult (thereby adding to response time and costs); and require repair work to access roads.

Having experienced several of these major cyclones in the recent past, Ergon must take prudent measures to reinforce its network against cyclone damage, in order to minimise disruptions to customers when these events do occur. For instance:[12]

- In North Queensland coastal regions, Ergon strengthens its poles to withstand wind pressures of mid-level Category 3 cyclones.
- In order manage the risk of catastrophic network failures resulting from cyclone damage, Ergon duplicates fully functional network operations control centres in different geographic locations. This means that Ergon splits it network operations control functions and maintains separate teams of staff at different locations.
- Ergon's operational staff receive special training to respond to emergencies arising from natural disasters of the kind that occur in Queensland. Most other DNSPs do not need to offer training to cope with cyclone disasters.

Each of these measures increases Ergon's costs relative to networks facing more normal circumstances.

2.2.3 Temperature

Queensland experiences by far the most consistently warm temperatures of any State within the NEM region as shown by Figure 25 and Figure 26. In addition, the regions served by Ergon and Energex experience the most high temperature days (i.e. in excess of 35 degrees Celsius) of the regions served by any DNSPs in the NEM.

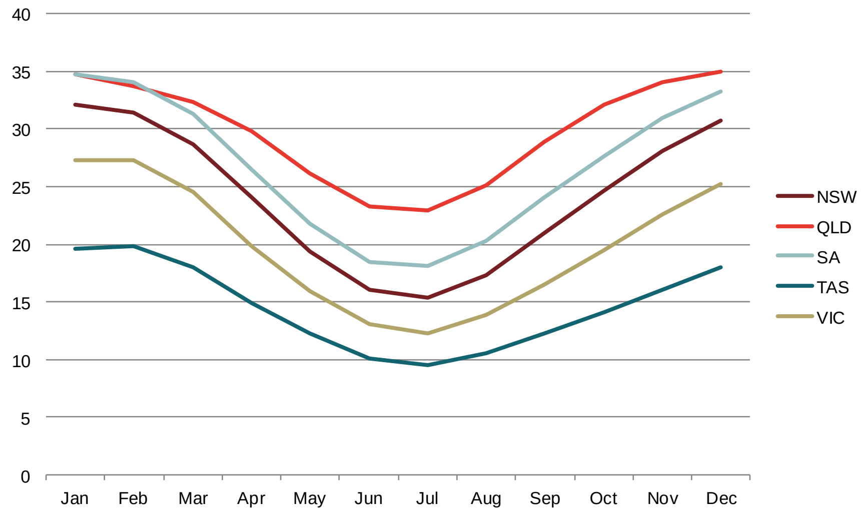
We understand from Ergon that high temperatures can induce conductor sag. Due to safety regulations that require the maintenance of clearance levels, areas that experience high, prolonged temperatures generally require greater maintenance activity. In addition, occupational health and safety (OH&S) regulations require that personnel working for prolonged periods in hot conditions be provided with breaks and shelter for hydration and cooling to

11 Queensland Department of Science, Information Technology, Innovation and the Arts, Tropical cyclone storm tide warning – Response system, November 2012, p.2.

12 See, for example, Ergon's response (dated 17 December 2014) to the AER's information request in relation to Ergon's special environment operating factors.

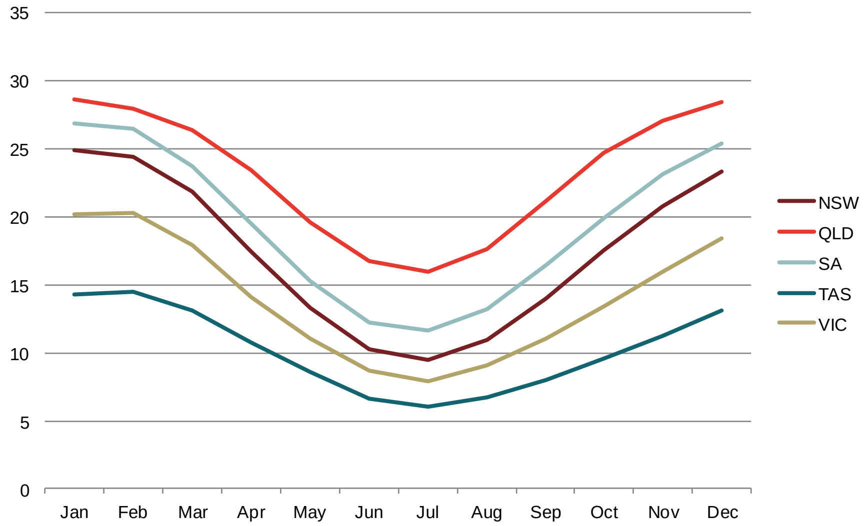
prevent against heat fatigue. Conducting inspections, maintenance and repair work in Queensland's hot climate adds to Ergon's OH&S compliance costs.

Figure 25: Average maximum temperatures (degrees C) by NEM State, 1961 to 1990



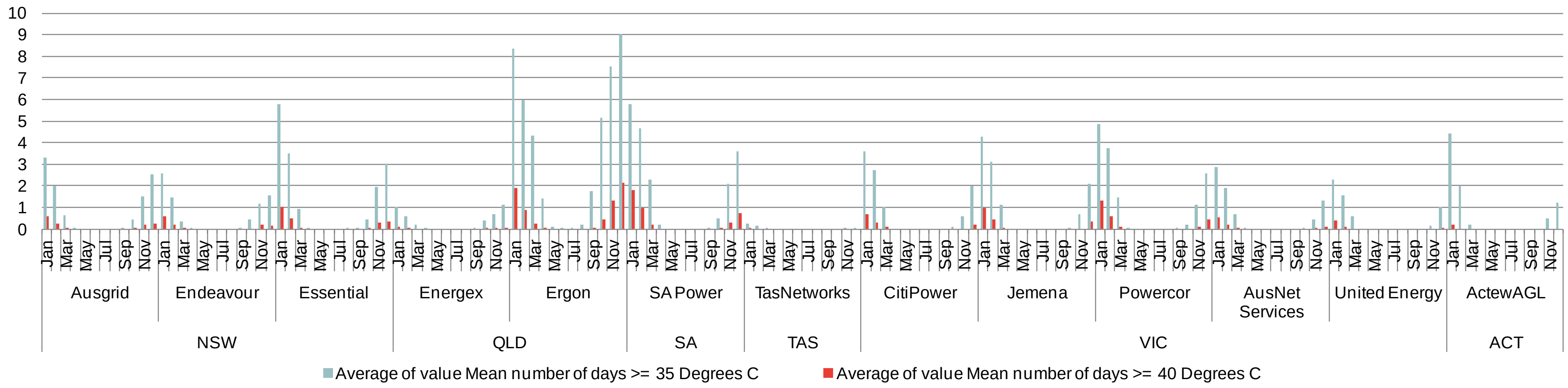
Source: Constructed using Bureau of Meteorology data

Figure 26: Average minimum temperatures (degrees C) by NEM State, 1961 to 1990



Source: Constructed using Bureau of Meteorology data

Figure 27: Average number of high peak temperature days per month by NEM DNSP, 1949 to 2014



Source: Bureau of Meteorology; AER benchmarking RIN data; Frontier analysis

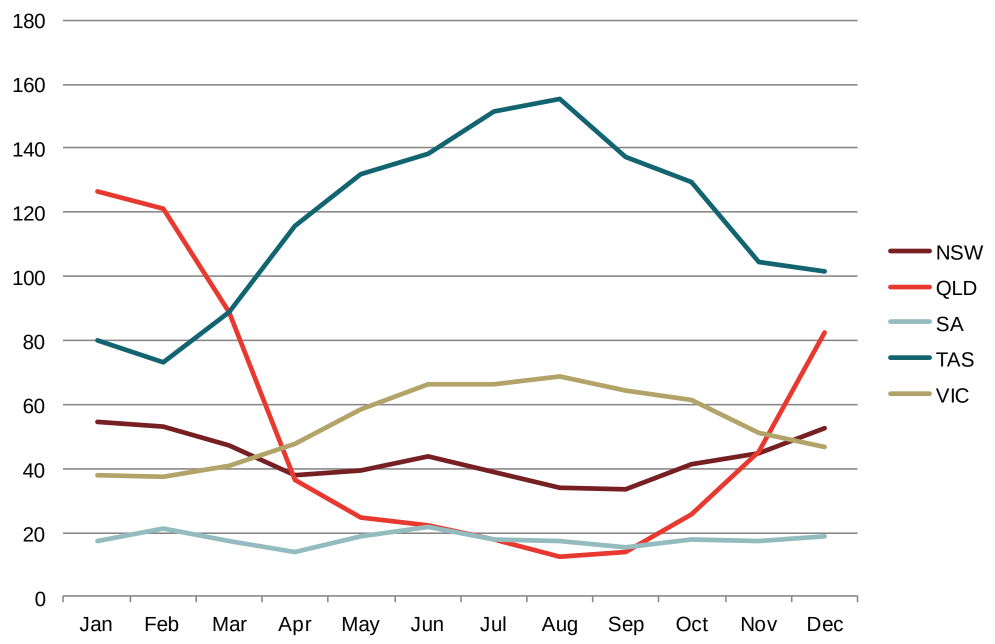
Ergon's circumstances are unique

2.3 Rainfall and humidity

Figure 28 shows that Queensland experiences the highest average rainfall (during peak months) of any State in the NEM apart from Tasmania.

Figure 29 maps BOM data on heavy (i.e. ≥ 25mm) rainfall to the weather stations reported by DNSPs as falling within their service areas.[13] These data show that, on average, Ergon and Energex experience the most days of heavy rainfall of all networks.

Figure 28: Average rainfall (mm) by NEM State, 1961 to 1990

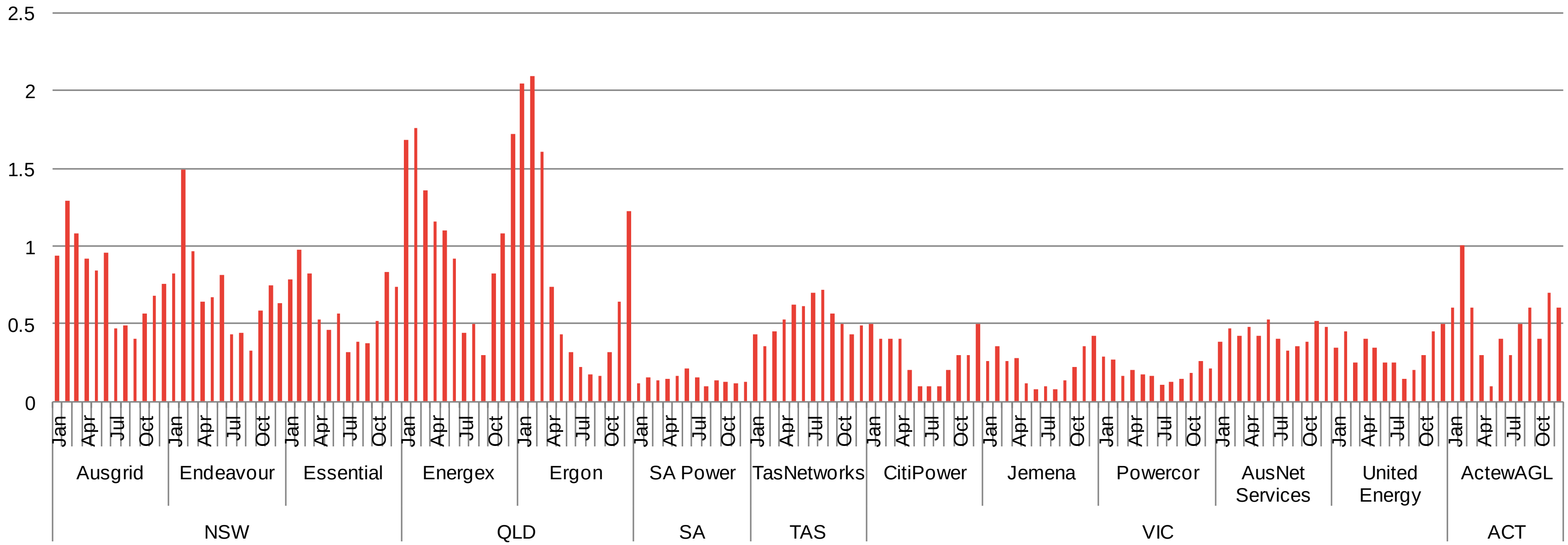


Source: Constructed using Bureau of Meteorology data

Figure 29 shows that the heaviest precipitation within Ergon's service area occurs in the warmest months of the year (i.e. December to February). This can facilitate rapid vegetation growth, particularly in the tropical regions of Queensland, which necessitates more aggressive vegetation management than in more temperate and less wet regions of the NEM.

[13] This chart, and others in this report that map climate data to weather stations within DNSP service areas, present data from all weather stations reported rather than only those that DNSPs report in RINs as being 'material', unless stated otherwise.

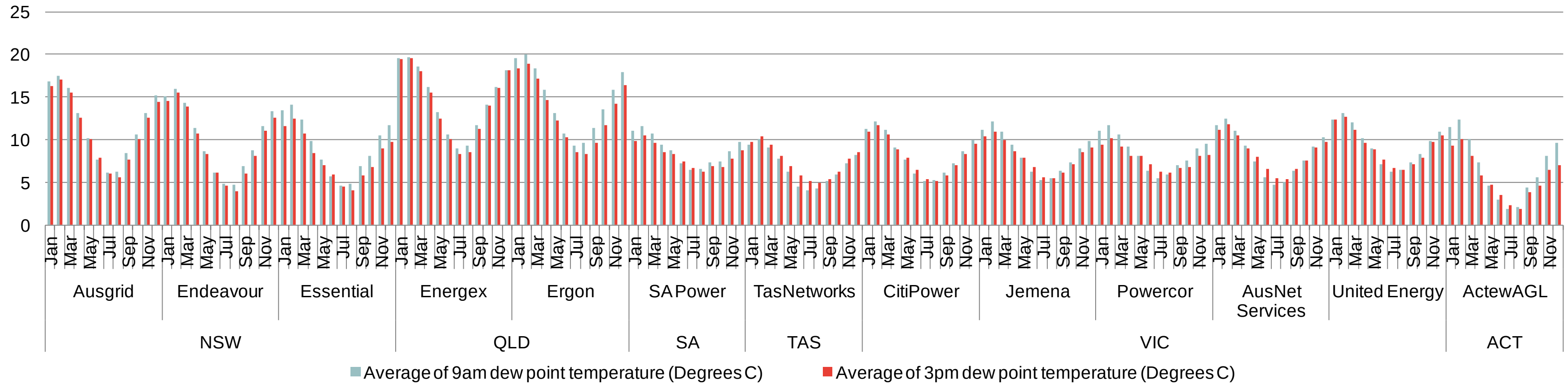
Figure 29: Average number of days per month of 25mm or more of rainfall by NEM DNSP, 1949 to 2015



Source: Bureau of Meteorology; AER benchmarking RIN data; Frontier analysis

Ergon's circumstances are unique

Figure 30: Average dewpoint temperature by NEM DNSP service area



Source: Bureau of Meteorology; AER benchmarking RIN data; Frontier analysis

Figure 30 plots average dew point temperature data by DNSP. The dew point temperature is the temperature at which air becomes saturated with water. At temperatures below this level, water vapour condenses into liquid water. The dew point temperature is often used as a measure of absolute humidity; the greater the dew point temperature, the more water vapour the atmosphere can hold. Figure 30 shows that amongst the various regions served by DNSPs in the NEM, the regions serviced by Ergon and Energex experience the highest levels of absolute humidity.

Figure 30 shows that humidity levels remain high within Ergon's and Energex's service regions for significant periods of the year (i.e. November to March). Ergon has noted to the AER that high rainfall and humidity, combined with high temperatures, accelerates the degradation of wooden poles. High humidity levels can also damage transformers (through expansion and contraction of transformer components as the air temperature fluctuates), increased rates of corrosion, cracking and damage to insulators. This can require more maintenance work than DNSP service areas with lower humidity levels.

2.4 Differences in regulatory obligations

Ergon has significantly higher opex relative to its comparator DNSPs associated with its regulatory obligations with respect to vegetation management, safety legislation and environmental levies. These costs are not explained by the cost drivers included in the AER's models. Ergon's regulatory obligations have also changed significantly over time, and are likely to change in the future. For these reasons, we recommend that the AER investigate the case for making company-specific adjustments for the factors identified below.

Vegetation management

We understand from Ergon that in some Australian States, local councils take responsibility for a large proportion of vegetation management activity near electric lines, particularly in urban areas that form part of the licence area covered by a particular DNSP. By contrast, Ergon performs this function alone across its whole operating region.

Safety legislations

Ergon has an obligation to operate under Queensland Electrical Safety legislation. We understand from Ergon that the associated regulations and Codes of Practice impose some unique obligations on Queensland DNSPs, which are not faced by the DNSPs outside Queensland. Ergon is required to periodically inspect and test every asset for suitability of continued service. For example, every timber pole must be inspected below the normal soil line to ascertain structural integrity. With its almost 1,000,000 poles, Ergon incurs significant costs to meet this obligation.

Given that the obligations on Ergon (and other DNSPs), arising from safety regulations, are imposed exogenously, they are at least partially non-controllable. We understand that Ergon intends to continue to comply scrupulously with all safety requirements placed on it by its regulators. It would however be perverse for the requirement for Ergon to comply with higher safety standards in some instances to be unfunded owing to inappropriately designed benchmarking and unjustified efficiency discounts. As we discuss in Section 5, these additional costs may require a company specific adjustment.

Furthermore, pressure on DNSPs to minimise safety compliance expenditure, by including these costs within those benchmarked, without also considering whether DNSPs are in fact meeting those obligations, may weaken incentives to meet safety standards. For this reason, these costs should not be included in the benchmarking analysis.

Environmental levies

Ergon also pays levies to the Electricity Safety Office (ESO) and the Queensland Competition Authority (QCA). In 2014-15 the ESO fees will be $4,520,400.00 and the QCA fees will be $50,000. As these costs are uncontrollable by Ergon, the AER should exclude them from its benchmarking analysis.

3 Controlling for unique factors within the AER's benchmarking models

3.1 Rationale

In Section 2 we discussed a number of factors unique to Ergon's operating environment that have not been taken into account in AER's benchmarking model. For most of these factors we have not been able to confirm the suitability of evidence available for Australian DNSPs for inclusion in a benchmarking model, or to source relevant data in the limited time available for the international sample used. However, with respect to two factors, subtransmission and customer density, there are relevant data in the AER's dataset. In this section we demonstrate that accounting for these factors within the AER's benchmarking model significantly alters the benchmarking results.

In undertaking this exercise we do not claim that the models presented in this section are the 'right' models, and that the AER should use these models to set allowances at this reset. As we noted in our report for Networks NSW, the AER's models are flawed because they rely on overseas data that are unreliable and should not be pooled with Australian data, and use Australian data that require much further testing and improvement.

However, the results in this section provide further confirmation that the AER's model fails to account for important sources of heterogeneity because, once controls (albeit imperfect ones) are introduced to account for some of this heterogeneity (i.e. once latent heterogeneity becomes explained heterogeneity) the efficiency scores generated by the model change markedly, and the range of efficiency scores for the Australian DNSPs in the sample is reduced by 40%.

Subtransmission

As noted above, differences between DNSPs with respect to the amount of subtransmission included in their networks reflect both differences in the geographical coverage of their networks and historical decisions made about the boundary between the transmission and distribution networks. Since high voltage circuits are more expensive to maintain than low voltage circuits, one would expect these differences to have a direct impact on operating costs. We would also expect the presence of such assets to signal the presence of further related challenges beyond those direct costs, arising in respect of serving areas that are large and sparse.

In the dataset used to develop the AER's benchmarking model, there is information on the circuit length in excess of 66kV for each distributor. We understand that for the Ontarian businesses the operating expenditures used in the benchmarking analysis by the Ontario Energy Board are adjusted to exclude any expenditure on assets in excess of 50kV.[14] The Ontarian DNSPs are recorded in the dataset used by EI as having no such assets.

To estimate the impact on opex of circuit length in excess of 66kV, we have modified the AER's benchmarking model by adding the share of circuit length that is above 66kV as an explanatory variable. Since many of the DNSPs have no such assets this variable is often equal to zero. We have therefore not taken the logarithm of this variable, since the logarithm of zero is not defined.[15] This is slightly different to the treatment of underground circuit length in the AER's model, which is included in logarithmic form.

Non-linear impact of customer density

Denser networks are likely to be able to serve a given number of customers with fewer assets than more sparsely populated networks, and are also likely to have lower operating costs. The AER's benchmarking model does not explicitly include a variable to capture customer density; however, it can be rewritten in an algebraically equivalent form in terms of a density variable.

The AER's benchmarking model includes the two variables log(customer numbers) and log(circuit length). We focus on just these two variables, in isolation from the other variables in the AER's model. The combined impact of these two variables on the log of opex is:

(A) b_1 log(customer numbers) + b_2 log(circuit length)

Using the rules for the logarithms of products and ratios of numbers, we can rewrite this as:

(B) b_1 log(customer numbers/circuit length) + $(b_1 + b_2)$ log(circuit length)

= b_1 log(customer density) + b_3 log(circuit length)

where $b_3 = b_1 + b_2$.

Expressions (A) and (B) are algebraically equivalent, and they will produce identical efficiency scores.

However, the relationship between customer density and opex could be quite complex. Not only are costs for very low density networks likely to be higher for a given number of customers (as more assets are required to serve), features of urban environments (such as congestion, requirements to deliver work overnight to avoid disruption in busy areas) might also impose additional costs on very high density networks, albeit offset by the reduction in the quantity of assets needed

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14 Pacific Economics Group, Productivity and benchmarking research in support of incentive rate setting in Ontario: Final report to the Ontario Energy Board, November 2013, p.33

15 There are various approaches to dealing with zero observations if one wishes to take logarithms of a variable with zeroes. However, for the present exercise we have not explored these approaches.

to serve a given number of customers. To account for possible nonlinearities in the relationship between the log of customer density and the log of opex, we have included the square of log(customer density), i.e. [log(customer density)]^2 in our modified benchmarking model. This is equivalent to assuming that the elasticity of opex with respect to customer density is not constant, but changes as customer density changes.

3.2 Results

The estimation results and some statistical measures for our modifications to the AER's benchmarking models are shown in Table 5,. The first column of estimation results, denoted as (1), reproduces the stochastic frontier benchmarking model developed by Economic Insights on behalf of the AER.[16] The column denoted (2) adds a variable that measure the share of circuit length above 66kV.

Column (3) rewrites the model in column (2) in the customer density form described in the previous section. Note that all the coefficients and statistical measures are the same as in column (2), apart from the coefficients for log(customer numbers), log(circuit length) and log(density). These latter coefficients are related to each other as shown in expressions (A) and (B) in Section 2. This confirms the assertion made above, that our re-parameterisation of the model does yield a specification that is equivalent from an algebraic perspective. Finally, the results in column (4) are for the model that adds the squared term for log(customer density) to allow for a non-constant elasticity of opex with respect to customer density that can vary with customer density.

The key new results are in columns (2) and (4). Column (3) is included to demonstrate that the AER's specification in terms of log(customer numbers) and log(circuit length) is algebraically equivalent to a specification incorporating log(density).

The estimation results for model (2) indicate that the share of circuit above 66kV is statistically highly significant as a determinant of opex, with a p-value of less than 1%. The estimation results for model (4) show that the square of log(density) is also a statistically significant determinant of opex, although only at the 10% level of significance.

Table 6 presents the estimated efficiency scores for the different models presented in Table 5. The table shows that, as might be expected, including the share of circuit above 66kV in the AER's benchmarking model has increased the efficiency scores of those DNSPs that have circuit above 66kV and decreased the

16 Economic Insights, Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs, 17 November 2014, Table 5.2.

efficiency scores of DNSPs that do not. The change for individual DNSPs can be quite dramatic – e.g. Endeavour's efficiency score has increased from 59.3 to 82.4, Ausgrid's from 44.7 to 64.1, and Ergon's from 48.2 to 63.4.

The average efficiency score is virtually unchanged, but the spread of efficiency scores has reduced by more than 40%, with the range decreasing from 55.2 to 32.7 and the standard deviation decreasing from 18.5 to 10.0.

Table 5. Estimation results for three variations of AER's benchmarking model

	AER's preferred model (1)	Model (1) plus share of circuit over 66kV (2)	Model (2) in density form (3)	Model (3) plus nonlinear density (4)
Log (customer numbers)	0.667***	0.668***		
Log (circuit length)	0.106***	0.107***	0.775***	0.788***
Log (ratcheted maximum demand)	0.214***	0.207***	0.207***	0.194**
Log (share of underground cable)	-0.131***	-0.157***	-0.157***	-0.133***
Share of circuit above 66kV		12.721***	12.721***	12.797***
Log(density)			0.668***	0.676***
$(\text{Log(density)})^2$				0.047*
Time trend	0.018***	0.019***	0.019***	0.018***
Constant	-26.526***	-28.377***	-28.377***	-27.711***
Country dummies				
New Zealand	0.050	0.171*	0.171*	0.157*
Ontario	0.157**	0.317***	0.317***	0.332***
Variance parameters				
mu	0.385***	0.369***	0.369***	0.385***
sigma_u	0.197	0.152	0.152	0.151
sigma_v	0.099	0.100	0.100	0.099
LLF	372.620	383.693	383.693	385.137
N	544	544	544	544
AIC	-723.240	-743.387	-743.387	-744.275
BIC	-675.952	-691.799	-691.799	-688.388

Source: Frontier Economics
*Note: *** denotes significant at 1%, ** significant at 5%, and * significant at 10%*

Table 6. Efficiency scores from estimated models shown in Table 5 (%)

DNSP	AER's preferred model (1)	AER's model plus share of circuit above 66kV (2) and (3)	AER's model plus share of circuit above 66kV and nonlinear function of density (4)
ActewAGL	39.9	53.3	51.8
Ausgrid	44.7	64.1	62.2
CitiPower	95.0	82.3	83.2
Endeavour Energy	59.3	82.4	78.9
Energex	61.8	72.6	69.6
Ergon Energy	48.2	63.4	67.4
Essential Energy	54.9	56.8	60.0
Jemena	71.8	63.2	61.6
Powercor	94.6	86.0	83.0
SA Power	84.4	74.3	73.7
AusNet	76.8	68.8	65.5
TasNetworks	73.3	66.0	63.1
United Energy	84.3	74.1	71.7
Summary statistics			
Mean	68.4	69.8	68.6
Standard deviation	18.5	10.0	9.4
Min	39.9	53.3	51.8
Max	95.0	86.0	83.2
Range	55.2	32.7	31.4

Source: Frontier

Note: The technical efficiencies reported in the table are the 'Battese Coelli' measures of efficiency.

The impact of including a nonlinear term for the density variable is not as dramatic, with a further reduction in the spread of the efficiency scores of about 5%. The increase in efficiency scores is largest for the two DNSP's with the lowest density networks, Ergon and Essential, whose efficiency scores have increased by about 4 percentage points and 3 percentage points respectively.

Controlling for unique factors within the AER's benchmarking models

3.3 Comments

In undertaking this exercise we do not claim that our models are the best way to account for differences in network configuration and customer density, or that the AER should adopt our models for benchmarking purposes.

Our aim is to show that differences in network assets and density can have a significant impact on opex, and that ignoring these factors in a benchmarking model can result in estimated efficiency scores that provide a very distorted picture of the true underlying efficiencies.

There are also additional asset classes to be considered – differences in circuit length at other voltage levels, in the types of poles used or in the types of transformers (often inherited legacies resulting from decisions made years or decades ago) – that are likely to have an impact on opex. Similarly, with respect to density, it is likely that a number of metrics will be required to capture the impact on opex of the spatial distribution of a network's customers and loads.

In our report for Networks NSW we argued that much of the residual variation in opex that the AER has chosen to interpret as differences in efficiency could, in fact, be due to latent heterogeneity not taken into account in the AER's benchmarking model. We presented two alternative models, the fixed and random 'true' effects models, which did allow for the residual variation to be interpreted as latent heterogeneity, and which resulted in a much narrower range of efficiency scores.

In this section we have shown that some of the factors treated as latent heterogeneity in our earlier report, and as inefficiency by the AER, can, in fact, be quantified and included as modifications to the AER's benchmarking model. In other words, we have been able to transform some the <u>latent</u> heterogeneity into <u>modelled</u> heterogeneity, and reduce the gap between the AER's benchmarking model and the 'true' effects models. There are plausible arguments that other factors outside management's control, for which we do not have data for the international sample used to estimate the AER's model, also have a material impact on opex. With relevant data it is likely that more of the remaining latent heterogeneity can be transformed into modelled heterogeneity, thereby further reducing the spread of efficiency scores.

We point out, however, that allowing for latent heterogeneity between DNSPs in the AER's benchmarking model does not mitigate the data problems we identified in our report for Networks NSW. As indicated in that report, the AER's models are flawed because they rely on overseas data that are unreliable and should not be pooled with Australian data, and use Australian data that require much further testing and improvement. These data shortcomings apply equally to our modifications of the AER's benchmarking model.

4 Adjusting for special factors through a two-stage process

4.1 Description of approach

In the previous section we have shown how the AER's benchmarking model can be modified to allow for differences between DNSPs in assets and customer density. However, this approach can only be applied to factors for which data are available for the international sample used to estimate the benchmarking model.[17]

To make adjustments for factors when only Australian data are available, a two-stage process can be adopted analogous to the two-stage process widely used to adjust for environmental factors when undertaking efficiency analysis using Data Envelopment Analysis (DEA) or Total Factor Productivity (TFP) index numbers. In the two-stage approach, efficiency scores are first estimated using either DEA or TFP; in the second stage these efficiency scores are then regressed on environmental variables that cannot be incorporated in the DEA or TFP analysis.

Coelli et al (2005) provide an explanation of the approach in the context of DEA:

> In the second stage, the efficiency scores from the first stage are regressed upon the environmental variables. The signs of the coefficients of the environmental variables indicate the directions of the influences, and standard hypothesis tests can be used to assess the strength of the relationships. The second–stage regression can be used to "correct" the efficiency scores for environmental factors by using the estimated regression coefficients to adjust all efficiency scores to correspond to a common level of environment (e.g. the sample means).[18]

After assessing a number of other possible approaches for taking into account the impact of environmental variables, Coelli et al conclude:

> [W]e recommend the two–stage approach in most cases. It has the advantages that:
>
> - it can accommodate more than one variable;
> - it can accommodate both continuous and categorical variables;
> - it does not make prior assumptions regarding the direction of the influence of the environmental variable;

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17 One could still use the approach for factors where only Australian data are available using techniques for dealing with missing data. However, in the present case, the missing data adjustments would be confounded with the country dummy effects included in the model.

18 Coelli et al (2005), *An Introduction to Efficiency and Productivity Analysis (2nd ed)*, Springer, pp 194 - 195.

- one can conduct hypothesis tests to see if the variables have a significant influence upon efficiencies;
- it is easy to calculate; and
- the method is simple and therefore transparent.[19]

An example of this approach in a regulatory context is the analysis undertaken by the Norwegian regulator (NVE). In stage one, NVE benchmarks total costs using DEA analysis controlling for eight cost drivers. In the second stage, NVE then corrects these DEA efficiency scores for differences in environmental factors considered to be outside of management control. We describe NVE's two-stage approach in more detail in Section 5.2 below.

An analogous two-stage approach has been adopted by EI in an international benchmarking study of postal service productivity for Australia Post,[20] the main difference being that EI used multilateral TFP index numbers rather than DEA to determine the efficiency scores in the first stage.

The two-stage approach can also be used when the first stage efficiencies are estimated using stochastic frontier analysis (SFA); see, for example, Kumbhakar and Lovell (2000).[21] This is not often done in practice, since, in most situations, one can incorporate the second stage environmental variables in the first stage SFA model directly, in the same way as we have done in Section 3, or in the efficiency term in the model.[22]

However, in the present case there are no data for the overseas businesses on most of the environmental variables of potential interest; and in the short time available to us for this analysis, we have not been able to fill that data gap. Hence, we cannot control for these factors in the same way as we did in Section 3; to do so would require data on these variables for the all overseas businesses as well as the Australian DNSPs. In these circumstances it seems appropriate to undertake a two-stage analysis to take account of the omitted environmental variables, using only the efficiency scores for the Australian DNSPs in the second stage regressions. In the next section we consider metrics for some of the environmental factors that might characterise material differences in the operating environments of the Australian DNSPs. In Section 4.3 we then

19 *Ibid.*, p 195.

20 Lawrence, D. and J. Fallon (2009), *International Benchmarking of Postal Service Productivity – A Report for Australia Post*, Economic Insights, p.23.

21 Kumbhakar, S. and C. Lovell (2000), *Stochastic Frontier Analysis*, Cambridge U.P., pp. 263 – 264. Kumbhakar and Lovell point out some statistical issues when using the two-stage approach with SFA. However, most of these issues also apply when using DEA or TFP in the first stage.

22 *Ibid.* Section 7.3.

illustrate how the efficiency scores obtained from the first stage SFA analysis can be adjusted for such differences.

4.2 Identification of variables

In the second stage analysis we investigate the impact on the first stage efficiency scores of a range of variables that characterise the operating environments of the DNSPs. The variables we consider can be classified as:

- customer density variables, which capture aspects of the spatial characteristics of the networks; and
- long-term weather variables.

There are other aspects of the spatial characteristics of the operating environment that we have not been able to investigate in the time available, such as load density and topography. Similarly, in regard to weather variables, we have not undertaken an exhaustive investigation, but have selected a subset of readily available variables related to extreme temperatures, rainfall and wind conditions. Below we discuss the customer density and weather variables we have considered in more detail.

4.2.1 Customer density

Rationale for exploring different density measures

As discussed in Section 2, there are very large differences in the spatial characteristics of DNSPs in Australia. Some DNSPs, like Ergon and Essential Energy, deliver electricity to a relatively small number of customers dispersed over large service areas. Other DNSPs, such as CitiPower, Jemena Electricity Distribution, and United Energy have much higher customer densities.

As no density measure captures all the spatial characteristics of a DNSP perfectly, it is reasonable to consider a range of different density measures to investigate whether the benchmarking results under alternative metrics vary materially.

The SFA benchmarking model relied on by the AER in its Draft Decision for the NSW/ACT networks (implicitly) takes account of customer density in a fairly simplistic way: EI includes as regressors in its SFA model the natural logarithm of customer numbers and the natural logarithm of circuit length. As shown in Section 3.1, the inclusion of these two variables, using this functional form, is algebraically equivalent to taking account of the **number of customers per kilometre of circuit length**.

However, the number of customers per kilometre of circuit length, as a measure of customer density, is imperfect. Another fairly standard measure of customer density that captures the nature of dispersed territories is the **number of customer per square kilometre of service area**.[23]

However, customers per service square kilometre of service area may also fail to capture well the practicalities of the distribution task. For example, two companies may have the same size service area and the same number of customers, but in one case almost all customers reside in a large city (and can therefore be served by relatively few assets occupying a small footprint) whereas in the other case the region is more rural and population is spread over the entire region. This second, rural company would need to construct many more assets to serve its region, but this key difference in the nature of the service regions would not be captured in a high level density measure. Hence, it may be desirable to consider more granular measures of customer density that reflects differences in the **distribution** of customers within DNSPs' service areas. Frontier recently constructed a set of bottom-up density measures for Ofgem, the energy regulatory in Great Britain, for use in its totex benchmarking models.[24]

Using a method analogous to the approach used in that study, we constructed a set of such density measures for Australian DNSPs by combining information on:

- DNSP service areas;
- postcodes; and
- Census data on populations, dwellings and land areas at the postcode level.

Construction of bottom-up measures of density using detailed Census data

The key steps involved in constructing these measures were the following:

- **Identify a unit of measure for sub-regions within each DNSP's service area.** There is a range of candidate measures that have been develop by the Australian Bureau of Statistics (ABS), but the most convenient is the Postal Area (POA), which corresponds reasonably well (though not perfectly) to postcodes in different regions of Australia.[25] The ABS publishes 2,147 POAs that cover the NEM region.

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23 We presented statistics on the two customer density measures mentioned above in Figure 15.

24 Frontier Economics, *Total cost benchmarking at RIIO-ED1 – Phase 2 report – Volume 1*, April 2013.

25 Other units of sub-regions developed by the ABS, as part of the Australian Statistical Geography Standard, include: Local Government Area (LGA); State Suburb (SSC); Commonwealth Electoral Division (CED); State Electoral Division (SED); Natural Resource Management Region (NRMR); Australian Drainage Division (ADD); and Tourism Region (TR).

- **Map each of the POAs collected to the relevant DNSP's service area**. We could not find a standardised mapping of POAs to DNSP service areas.[26] In the absence of a standardised mapping (e.g. published by the AER or AEMO), the ideal way to achieve a mapping of POAs to service areas would be through a cooperative effort between all DNSPs. Frontier achieved a mapping of postcodes to the service areas of distribution network operators in Great Britain by this means when it developed density distribution metrics on behalf of Ofgem. However, there was no opportunity or forum, within the current regulatory process, for us to undertake a similar exercise in Australia. Therefore, we had to rely on information obtained from the websites of various DNSPs, Energy Australia, and by cross-checking weather station postcode data reported in the benchmarking RIN responses from DNSPs in order to achieve a mapping.

  We were able to achieve a fairly close mapping of POAs to service areas. However, in the time available we were unable to resolve issues such as doubling up of POAs in instances where POAs cross State boundaries or DNSP service areas. The process we used to map POAs to DNSP service areas and the limitations of this mapping, are set out in Appendix A to this report.

- **For each POA, collect data on POA surface area (measured in km^2) and proxies for the number of electricity customers.** In the UK, the Department of Energy and Climate Change (DECC) compiles statistics on the number of meters and the amount of energy supplied within (the UK's equivalent of) a POA. However, in Australia, such data do not exist. However, the Australian Bureau of Statistics does, through Census information, compile statistics on possible proxies for the number of energy customers in a POA. Two of these proxies include:
  - the number of individuals; and
  - the number of dwellings.
- **For each POA, calculate the relevant customer densities.** Using the latest (i.e. 2011) Census data, we calculated:
  - population densities (i.e. number of individuals/km^2); and
  - dwelling densities (i.e. number of dwellings/km^2).
- **Normalise the POAs by area.** Because POAs vary in size from one another, it was necessary to normalise each POA by weighting it by POA

[26] We note that when completing the benchmarking RIN templates DNSPs are required to report the postcodes of weather stations within their service areas. This is a helpful start, but is not an exhaustive list of postcodes within each service region. It would be helpful if the AER could collect and publish these data, going forward.

surface area, in order to ensure that we could achieve measures that were comparable across all POAs.

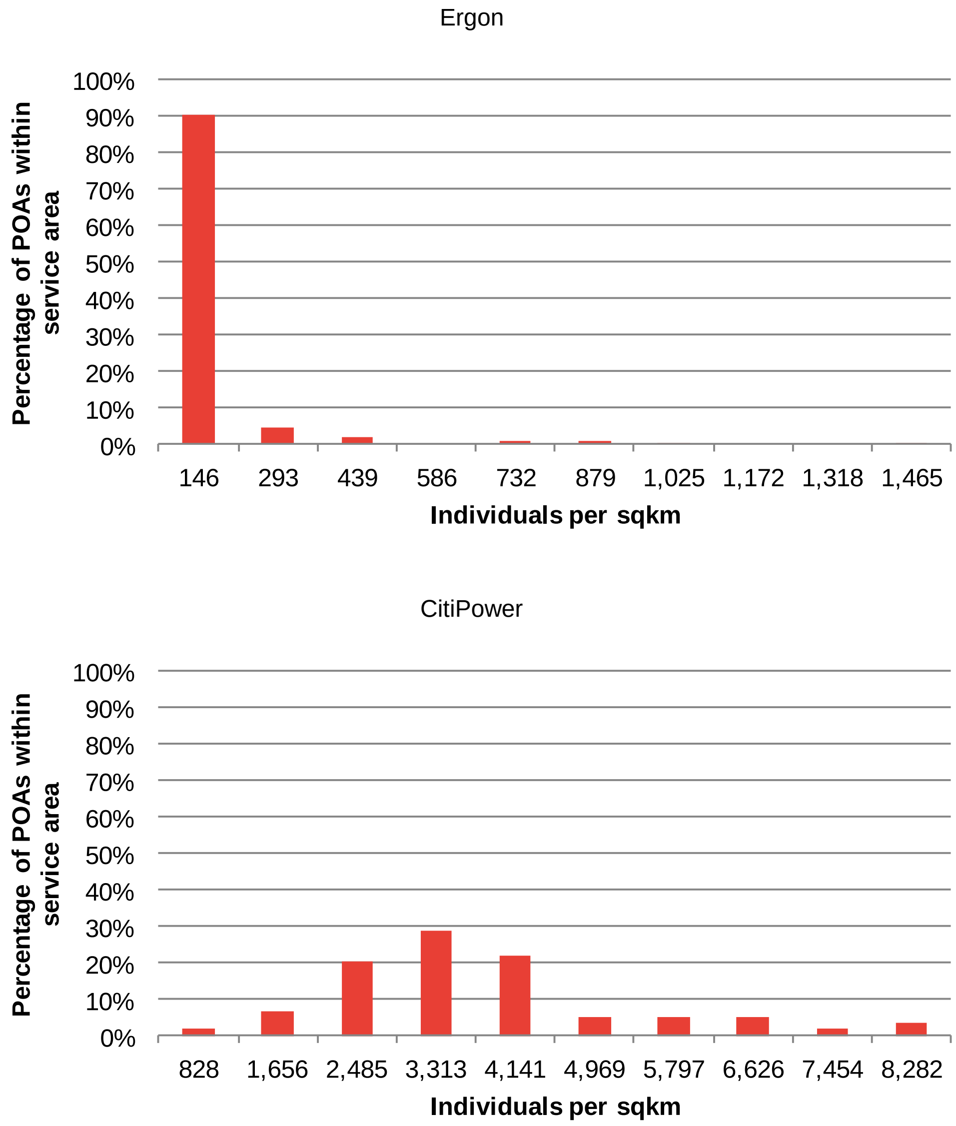
- **Construct density distributions for each DNSP.** We then aggregated the normalised POAs into density distributions. In order to do this we calculated the proportion of POAs, within a DNSP's network, that fell within a defined density range. To illustrate this, Figure 31 plots population density distributions for Ergon and CitiPower.[27] The Ergon's histogram shows that over 90% of POAs within its service area had a population density of 146 individuals per km^2 or less; by contrast, CitiPower's histogram shows that less than 2% of its POAs have a population density of 828 individuals per km^2 or less. Ergon's density distribution is very right-skewed (i.e. the mass of the distribution is pushed to the left-hand-side of the distribution) indicating that it operates in a very sparse service area. By contrast, CitiPower's distribution is much closer to being bell-shaped: very few of its POAs are sparsely populated; a fairly large proportion (i.e. the peak of the distribution) is moderately dense; and a small but nontrivial proportion of its POAs are very densely populated. The dwelling density distributions for all DNSPs showed a very similar pattern to the population density distributions.
- **Derive density metrics by examining the properties of the distributions constructed.** We calculated a range of statistics to capture the underlying heterogeneity of population densities between DNSPs, which are summarised in Table 7 below.

Table 7: Density metrics based on POA data

Metric	Description
Mean	Mean density, weighted by POA surface area. Conceptually very similar to the number of customers per square kilometre of service area, but derived from using ABS Census data
Median	The mid-ranked density when all POA densities are ordered, weighted by POA surface area. We favoured the median over the mean because it is less sensitive to potential errors arising from misallocation of POAs to DNSPs and other data errors
Skewness	Skewness of density, weighted by POA surface area, summarising the extent to which the tail on one side of the distribution is longer than the other (equivalently, whether the bulk of the distribution lies to below or above the mean)
Kurtosis	Kurtosis of density, weighted by POA surface area, summarising how "peaked" the distribution is
Gini coefficient	A measure of inequality between zero and one where zero would imply that density is equal across the DNSP's surface area and 1 would imply that customers are concentrated in one unit of the DNSP's surface area, with the remaining area being empty

27 Density distributions for all the DNSPs are presented in Appendix B of this report.

Figure 31: Example: population density distributions for Ergon and CitiPower



Source: Frontier Economics analysis of ABS 2011 Census data

4.2.2 Weather variables

In addition to the density variables discussed above, we considered a number of long-term weather variables to capture differences in operating environment between DNSPs. The data for the weather variables were taken from the Bureau of Meteorology website. The variables considered, together with the metrics used in our analysis, are listed in Table 8.

Table 8: Metrics used in the weather analysis

Variable	Metric used
Annual maximum wind gust speed (km/h)	90th percentile across weather stations
Monthly highest daily rainfall (mm)	90th percentile across months and weather stations
Annual decile 9 of total rainfall (mm)	Average across weather stations
Average number of days in a year with at least 25mm of precipitation	Average across weather stations
Average dew-point temperature (°C) at 9am across years	Average across weather stations
Average dew-point temperature (°C) at 3pm across years	Average across weather stations
Approximate average relative humidity (%) at 3pm across years	Average across weather stations
Average number of days in a year when the daily maximum air temperature was equal or greater than 30 °C	Average across weather stations
maximum air temperature was equal or greater than 35 °C	Average across weather stations
Average number of days in a year when the daily maximum air temperature was equal or greater than 40 °C	Average across weather stations
Annual decile 9 of maximum air temperature (°C)	Average across weather stations

Notes:

1. *For the Economic Benchmarking RIN, DNSPs are required to report all weather stations in their service area and to indicate which weather stations are not relevant to the management of their networks. UED did not indicate any weather station in its service are as 'not relevant'; hence, for the purposes of this analysis, all weather stations reported by UED have been included in calculating weather-related variables*
2. *For ActewAGL there was no information on the wind gust speed variable readily available. Hence the analysis for this variable is based on 12 instead of 13 observations*

4.3 Results

In the second stage regression analysis, we regressed the estimated efficiency scores for the 13 Australian DNSPs from the AER's benchmarking model and Frontier's modification of that model (model (4) in Section 3.1) on the various density and weather variables discussed in the previous section. We also included in the set of explanatory variables the share of circuit above 66kV, which is an additional variable included in our modified version of the AER's benchmarking model.

Given that there are only 13 observations available for this analysis, standard errors are likely to be quite large, making it difficult to obtain statistically significant results. Hence we limit the analysis to simple regression models, with each model having only one of the density, weather or share of circuit above 66kV variables as an explanatory variable.

Since SFA efficiency scores are constrained to lie between 0 and 1, the appropriate specification for the regression models would be the tobit model. However, since none of the observations are very close to the limits, ordinary least squares (OLS) regression produces almost identical results to the tobit specification, except that for OLS estimation, computer packages report finite sample standard errors, t-values and probability values (p-values), whereas for the tobit model they report asymptotic values. Since asymptotic values are less appropriate for small sample sizes, in this study we report the OLS results.

Table 9 lists the estimated coefficients and p-values for all the variables whose coefficients in the simple regressions had a p-value of 15% or less. The p-value for an estimated coefficient gives the probability that the estimate could have been produced by chance, even though there is no true relationship between the efficiency scores and the explanatory variable. While it is customary when reporting estimation results to only regard p-values of 10% or less as indicating statistically significant results, in view of the very small sample size in the current analysis, we consider that somewhat larger p-values still provide useful information about a variable's potential impact on the efficiency scores. Hence we have set the limit for reporting results at 15% rather than 10%.

Table 9 shows that the share of circuit above 66kV is statistically highly significant. This is consistent with our analysis of the AER's benchmarking model in Section 3.2. When we added the share of circuit above 66kV as an extra variable in the AER's model it was shown to be a statistically highly significant determinant of opex. Since the AER's benchmarking model omits this variable, it is to be expected that the share of circuit above 66kV will show up in the second stage analysis as a significant explanatory of the AER's efficiency scores.

In regard to the density variables, only one of these reached the 15% p-value limit, namely customers per sqkm of service area, which had a p-value of 10.5%

Of the eleven weather variables, five reached the 15% p-value limit, of which three rainfall-related variables and the relative humidity variable were statistically significant at the 10% level or better. This suggests that high rainfall and relative humidity impose costs on networks that have not been taken into account in the AER's benchmarking model.

The last weather variable in the table is a measure of extreme winds. While this variable, with a p-value of 12.1% is not quite statistically significant at the 10% level, it is not surprising that extreme wind events might contribute to opex, and failure to account for extreme wind events could distort the benchmarked efficiency scores.

Table 9: Significance of variables in second stage regressions for AER's efficiency scores

Variable	Estimated coefficient	p-value
Circuit length above 66kV		
Share of circuit above 66kV	-9.140***	0.000
Density variable		
Customers per sqkm service area	0.00016	0.105
Weather variables		
Mean [annual Mean number of days of rain >= 25 mm]	-0.039***	0.005
Mean [annual Decile 9 monthly rainfall (mm)]	-0.00034*	0.055
90th Percentile [value Highest daily rainfall (mm)]	-0.0021**	0.020
Mean [average relative humidity]	0.019*	0.085
90th Percentile [annual Maximum wind gust speed (km/h)]	-0.0038	0.121

*Note: *** denotes significant at 1%, ** significant at 5%, and * significant at 10%*

We also undertook a second stage regression analysis for the efficiency scores resulting from model (4) in Table 5, i.e. the efficiency scores shown in the last column of Table 6. Model (4) is a modification of the AER's benchmarking model in which the share of circuit above 66kV and the square of log (customer numbers/circuit length) have been added to the AER's set of variables. Table 10 lists the estimated coefficients and p-values for all the variables whose coefficients in the simple regressions had a p-value of 15% or less.

As might be expected, in the second stage regressions for these modified efficiency scores the share of circuit above 66kV is no longer significant. Since it is now included in the first stage model for opex, the efficiency scores for model (4) have, in a way, already been adjusted for the share of circuit above 66kV.

In regard to the density variables, the same density variable as before – customers per sqkm – is the only density variable that meets the 15% p-value criterion.

What is somewhat unexpected is that in the second stage regressions for the model (4) efficiency scores, only one of the weather variables has a p-value less than 15%, namely the variable for wind gust speed. All the rain-related variables and the humidity variable are now insignificant.

Table 10: Significance of variables in second stage regressions for efficiency scores from Frontier's modification of AER's benchmark model

Variable	Estimated coefficient	p-value
Density variable		
Customers per sqkm service area	0.000076	0.134
Weather variable		
90th Percentile [annual Maximum wind gust speed (km/h)]	-0.0019	0.111

Source: Frontier Economics

Notes:

1. **** denotes significant at 1%, ** significant at 5%, and * significant at 10%*
2. *The dependent variable is the set of efficiency scores derived from model (4) in Table 5*
3. *There are only 12 DNSPs in the sample since data for the wind gust speed variable was not readily available for the weather stations reported by ActewAGL*

We have used the second stage regression model results reported in Table 10 to calculate adjusted efficiency scores that "correct" the efficiency scores of Frontier's modified benchmarking model (4) for differences between DNSPs with in regard to customer per sqkm of service area and wind gust speed, respectively. Table 11 presents these second stage efficiency scores. For comparison, the efficiency scores from the AER's benchmarking model, and the pre-adjustment scores for model (4) are also presented in the table.

Table 11 shows that adjusting for either of these factors has a material impact on the efficiency scores for some of the DNSPs, even though the variables are statistically not quite significant at the 10% level. For example, adjusting for differences in the density variable reduces CitiPower's efficiency score from 83.2 to 70.0, while for the other DNSPs the adjustments are quite small.

Adjusting for the wind gust speed variable results in the efficiency score for TasNetworks increasing from 63.1% to 71.5%, Ergon's score increasing from 67.4% to 73.3%, and AusNet's from 60.5% to 65.5%. On the other hand, the efficiency score for CitiPower decreases from 83.2% to 77.9%. The impact of the second stage adjustment for other networks is more modest.

Table 11. Stage two adjusted efficiency scores (%) for model (4) compared with unadjusted scores and the scores for the AER's benchmarking model

DNSP	AER's benchmarking model	Unadjusted efficiencies for modified model (4) in Table 5	Model (4) efficiencies adjusted for customer per sqkm	Model (4) efficiencies adjusted for wind gust variable
ActewAGL	39.9	51.8	53.0	
Ausgrid	44.7	62.2	63.4	62.8
CitiPower	95.0	83.2	70.0	77.9
Endeavour Energy	59.3	78.9	80.4	77.0
Energex	61.8	69.6	71.0	70.2
Ergon Energy	48.2	67.4	69.1	73.3
Essential Energy	54.9	60.0	61.8	61.0
Jemena	71.8	61.6	60.8	61.2
Powercor	94.6	83.0	84.7	81.2
SA Power	84.4	73.7	75.4	74.3
AusNet	76.8	65.5	67.2	60.5
TasNetworks	73.3	63.1	64.8	71.5
United Energy	84.3	71.7	70.2	69.1
		Summary statistics		
Mean	68.4	68.6	68.6	70.0
Standard deviation	18.5	9.4	8.4	7.2
Min	39.9	51.8	53.0	60.5
Max	95.0	83.2	84.7	81.2
Range	55.2	31.4	31.7	20.7

Source: Frontier Economics

Notes:

1 *Results for only 12 DNSPs are reported in the fifth column since data for the wind gust speed variable were not readily available for the weather stations reported by ActewAGL*
2 *The adjustments have been calculated at the sample average values of the independent variables*

4.4 Comments

Our aim in this section has been to show that using a two-stage approach it is possible to adjust efficiency scores for factors in DNSPs' operating environments that impact on opex, but that were not accounted for in the first stage SFA benchmarking model. The size of the second stage adjustments are, in some cases, quite large, and they can have a material impact on a DNSP's efficiency score, even if the regression used to quantify the adjustments is statistically only weakly significant. The weak statistical significance of some of the results is no doubt, to a considerable extent, due to the small sample available for analysis.

Given the short timeframe available for this assignment, we have only been able undertake a very preliminary assessment of metrics and data sources that might be useful in quantifying the environmental factors that might make a material difference to a utility's operating costs. Nevertheless, there are quite strong indications that the size of the adjustments for individual factors can have a material impact on a utility's efficiency score. It is quite possible that the cumulative effect of adjustments for a range of environmental factors would result in quite a different picture in regard to the absolute and relative efficiencies of Australia's DNSPs compared to that presented by the AER's benchmarking model. We stress, however, that the analysis presented in this section has been undertaken mainly for illustrative purposes, and, given the strong reservations about the quality of the data detailed on our report for Networks NSW, we make no claims to any of the empirical results in this section providing a sound basis for regulatory determinations.

5 Special factor adjustments

Benchmarking is a tool for monitoring the relative performance of an entity. Benchmarking can play an important role in regulatory reviews, allowing the regulator to protect customers from inefficient costs and to buttress other incentives for cost efficiency. However, as discussed above, benchmarking can only play this role effectively if it is well designed and used with care. Poorly designed benchmarking used recklessly can result in arbitrary disallowances reasonable of costs, hampering the planning and delivery of network services, increasing risk for investors, and damaging the interests of customers.

Differences in cost to serve can arise from a number of potential sources including underlying differences in:

- network outputs (e.g., customer numbers, maximum demand, energy delivered, etc)
- input costs (e.g. labour rates, local taxes);
- operating environment (e.g. climate, topography, soil properties, vegetation, and the urban/rural nature of certain areas);
- regulatory obligations (including safety standards);
- past (legacy) configuration decisions and planning constraints;
- random statistical noise; and
- current managerial and operating efficiency.

When determining efficiency discounts in regulatory proceedings, it is only the excess cost owing to the last type of underlying difference – managerial performance – that should be taken into account. However, distinguishing between the different drivers of performance is a challenging task. Ideally, regulators would control for all the drivers of performance within a single benchmarking model.

In practice, however, regulators face a number of limitations, such as limited sample size, the availability of data, and challenges in quantifying the most important external factors that explain differences in performance (over time and/or between networks). This may imply that the regulator is unable to control for all the factors that affect performance within its benchmarking model. However, failure to account for these factors may result in some companies being erroneously judged as inefficient relative to others. This could lead to a regulator mistaking a justified difference in cost for a difference in efficiency.

To minimise errors of this kind, European regulators make a number of normalisations, exclusions and adjustments to their benchmarking models in an attempt to ensure that their comparisons are more like-for-like. For the purposes of our discussion in this report, we refer to such normalisations, exclusions and adjustments as 'special factor adjustments'.

The remainder of this section is structured as follows.

- In Section 5.1 we discuss Ofgem's approach towards accounting for special factors through a number of cost adjustments, normalisations, and exclusions from its benchmarking analysis.
- In Section 5.2, we discuss NVE's approach to accounting for special factors, both within its benchmarking model, and through a second-stage adjustment to its efficiency scores.
- In Section 5.3 we provide a summary of the special factors that are relevant in Ergon's case; and
- In Section 5.4 we outline our medium-term recommendations for the AER with respect to special factor adjustments in Australia.

5.1 Ofgem's approach

Ofgem uses benchmarking analysis to inform its cost allowances for the 14 GB DNOs. Ofgem uses a variety of techniques to assess the relative efficiency of the GB DNOs, including top-down econometric modelling, bottom-up analysis of unit costs, engineering assessments and other expert assessments.

In developing its method, Ofgem has in the past made a wide range of adjustments to elements of its benchmarking in order to ensure it minimises the extent to which justifiable differences in cost confound its benchmarking.

We begin by discussing briefly how Ofgem's approach to benchmarking has evolved over time as it has learned by doing at previous reviews, and as more and better data has become available We then:

- discuss Ofgem's rationale for making different types of special factor adjustments;
- outline the process followed by Ofgem when determining special factor adjustments;
- briefly illustrate the magnitude of Ofgem's special factor adjustments in the most recent regulatory control periods; and
- provide examples of how these adjustments are quantified.

5.1.1 Evolution of Ofgem's approach

Ofgem's approach to benchmarking has changed markedly over the course of recent price controls. As more and better data has become available it has adopted more granular and, in some cases, more sophisticated techniques to support its efficiency assessment.

Ofgem first used top-down econometric benchmarking to assess opex efficiency for the 14 GB DNOs in its third electricity distribution price control review DPCR3 (2000 – 2002), using a single year of data from 1997/98. It used a similar approach in DPCR4 (2005 – 2010), using data a single year of data from 2001/02. These were the latest years of data available at the start of the respective regulatory controls. Benchmarking also played a key role at DPCR5, where Ofgem first began to pursue benchmarking of disaggregated cost heads in addition to the top down techniques on which it had traditionally relied. In its recently completed ED1 review, Ofgem has again relied on both top down (totex) models and on a range of disaggregated models, but has now made much more use of historic and forecast data to deploy panel techniques.

Over the course of this period Ofgem has deemed it necessary to make a wide variety of adjustments to its benchmarking, often in the form of pre-modelling adjustments to cost, to account of differences between companies. As its techniques have evolved, in the light of its own experiences and feedback from the sector and beyond, so have the type and scale of adjustment.

For example, when Ofgem relied on a single year cross section, Ofgem found it necessary to take more account of exceptional costs, in order to prevent its assessment being distorted by short lived, non-recurring events. As it has made more use of panel data, it is no longer so concerned with removing exceptional costs, as over a period of time it may be more reasonable to presume that exceptional events will affect each company from time to time, and any effect will be smoothed out.

Similarly, at DPCR3, when the data available to Ofgem was of poor quality and there were significant concerns over the consistency of data reporting, Ofgem made a range of adjustments to create greater consistency. As Ofgem and the companies have worked to improve the quality of data reporting, such adjustments have become far less necessary.

Lastly, Ofgem's decisions, in respect of whether it is necessary to adjust for some company specific circumstance, have depended on the details of its model and the cost drivers it uses. Some adjustments it has made in the past, it may no longer feels it is necessary to make now at all (or to the same extent) in the light of some methodological innovation.

This discussion reveals that there is no unambiguously ideal way to account for company specific factors. It depends on the nature of the differences, and many other elements of the chosen benchmarking technique and model. Ofgem's evolving approach appears to reflect this view.

Ofgem sought to place more structure on its approach at the start of DPCR5 which ran from 2010– 2015. Ofgem developed a set of criteria to determine which costs should be included within its benchmarking models.[28] These principles were reinforced by Ofgem at the start of RIIO-ED1 (2015 – 2023), the latest electricity distribution regulatory control in GB. Ofgem's criteria include the following.

- The DNOs should have influence over the cost, and uncontrollable costs should be excluded.
- The activity associated with the cost should be undertaken by most of the DNOs, rather than being geographically specific.
- The costs should be relatively stable, rather than one-off or 'lumpy'.
- The cost should provide appropriate coverage of the operational activities.
- Boundary issues with the costs should be understood.

Where Ofgem has identified costs that do not meet the criteria above, it has accounted for these in a number of ways:

- In some cases, Ofgem has included these costs in its benchmarking, but only after adjusting and normalising the costs to ensure that its comparisons across DNOs is like-for-like.
- In other cases, Ofgem has excluded these costs from its benchmarking altogether, and dealt with them on a more case by case basis.

Below, we provide an overview of the different types of special factor adjustments that Ofgem has made in its benchmarking analysis for the network companies that it regulates. We provide examples of the cost categories that were relevant in Ofgem's case. However, as the AER is still at the initial stage of gathering and processing evidence from the DNSPs, we note that it is not necessarily the most recent precedent from Ofgem that is most relevant in the AER's case. The AER may need to make a number of adjustments to ensure consistency of the DNSP data, for example, as Ofgem needed to do in DPCR4.

We therefore provide a review of the different types of adjustments that Ofgem has made in the past, rather than reviewing only the most recent precedent. While Ofgem did not make a number of these adjustments for the GB DNOs in the most recent regulatory control, they may well be necessary in the AER's case for the Australian DNSPs.

5.1.2 Rationale for making special factor adjustments

As Ofgem's approach to benchmarking has evolved over time, it has made a wide range of adjustments to benchmarked costs, for a variety of reasons. Based

[28] Ofgem (2009), 'Electricity distribution price control review – initial proposals – allowed revenue – cost assessment', August, Para 4.2.7.

on our assessment of Ofgem's conduct, the underlying rationale for making special factor adjustments might be categorised as when:

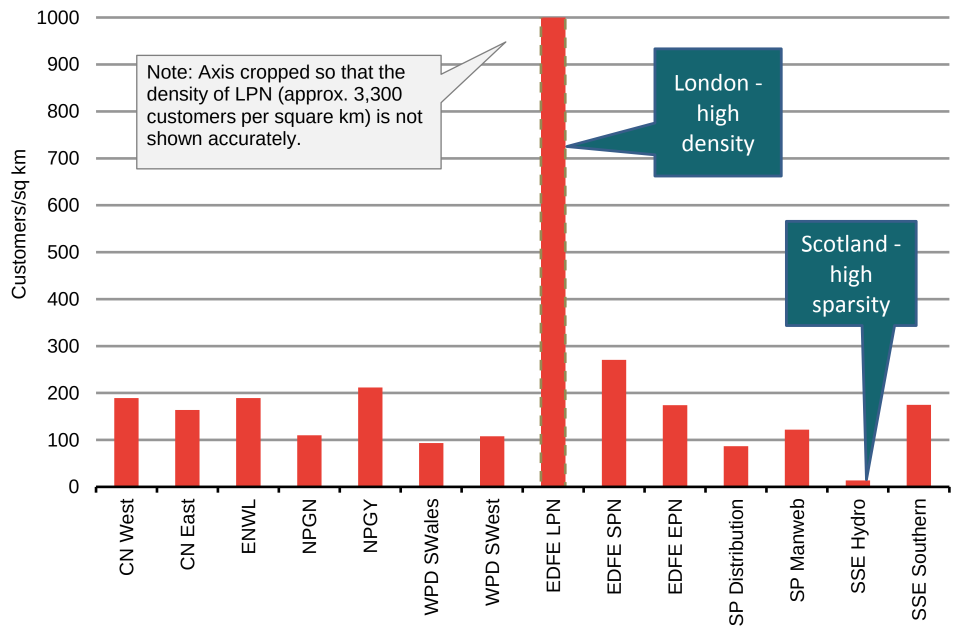
- the costs are unique to only one company for justifiable reasons specific to that company;
- the costs are unexplained (or explained poorly) by the available cost drivers;
- there is a significant different between history and forecasts;
- the costs are (very largely or entirely) uncontrollable yet vary between companies;
- the costs are outside the regulatory control;
- there are differences in cost allocation principles between companies; and
- atypical/exceptional costs arise due to severe weather/environmental conditions.

When costs are unique to only one company

Where costs are incurred by only one or a few DNOs in the sample, Ofgem has considered it appropriate to exclude these costs from its main benchmarking model. The costs excluded from core benchmarking may then be dealt with through a separate allowance, or subject to a bespoke analysis.

For example, in both RIIO-ED1 and DPCR5, Ofgem has made company-specific adjustments for the DNOs operating in London (EDFE LPN) and Scotland (SSE Hydro) for a range of factors associated with very high density and very high sparsity respectively. By so doing Ofgem recognises that very high density and sparsity can give rise to unique circumstances that result in higher costs to serve than is the case for networks serving more typical service areas.

Figure 32. Customer density - GB DNOs



Source: Ofgem data

This relationship between density and cost is made complex by two potential effects:[29]

- **Geometric effect** – Fewer assets are needed to serve customers as they become closer together, reducing costs as density increases. Conversely, networks that operate in more sparse regions typically have a high volume of small assets spread evenly over their service area. This implies a downward sloping relationship between density and total costs.
- **Urbanisation effect** – At some point the geometric effect could be, at least partly, offset by increased costs associated with serving high density areas. For example, this could be the result of safety requirements resulting in more distribution assets being located underground in urban areas, increased traffic congestion, more difficulty accessing infrastructure, and associated higher installation and maintenance costs.

In principle both low density and high density could lead to higher costs, implying a U-shaped relationship between connection density and total costs.

[29] The characterisation of these two effects follow the notation used in Frontier Economics and Consentec, 2009, "Impact of connection density on regional cost differences for network operators in the Netherlands", A report prepared for Energiekamer.

This would be the case if the geometric effect dominates at low density levels, while the urbanisation effect dominates at higher densities.

Ofgem has made a sparsity-related company-specific adjustment for SSE Hydro in every regulatory control period since DPCR3, and a density-related company-specific for EDFE LPN in the latest regulatory control, RIIO-ED1.

We would expect sparsity to be a significant driver of Ergon's costs (as discussed in Section 5.3 below), and potentially also for other DNSPs, and recommend that the AER consider making a special factor adjustment for sparsity-related opex.

Ofgem's company specific special factors are not limited to those that address customer density effects. For example, Ofgem has also made further adjustments for SSE Hydro is respect of:

- Submarine cables, as SSE Hydro has an extensive 33kV and 11kV subsea cable network that is required to take power to the different islands and also to cross sea lochs; and
- Remote location generation, as SSE Hydro ensures security of the supply on the islands it serves with the help of dedicated diesel generators that give rise to costs not incurred on a similar scale by other DNOs.

Whilst these adjustments are not particularly substantial on per annum basis, Ofgem does recognise that it would be unreasonable not to allow them.

Ofgem also made a company-specific adjustment for a third DNO, SP Manweb, at both DPCR5 and RIIO-ED1.

SP Manweb requested a special factor adjustment for the higher costs associated with the operation of its legacy interconnected network configuration, relative to the costs of operating a typical radial network as owned by the remaining GB DNOs. We understand that if SP Manweb were free to reconfigure its network completely, it would now choose not to have those assets, but to deliver the extra resilience they provide through other means. However, given that those assets exist, even though they are inefficient relative to some greenfield alternative, it is more efficient to continue to operate them than it would be to reconfigure the network, albeit that this may make SP Manweb appear to have inefficiently high expenditures in some cost heads.

The principal costs arising from these interconnected networks relate to the increased number of substations required and the associated increase in volume of transformers, switchgear and substations. As SP Manweb's costs are influences by its legacy decisions, which cannot be changed readily, Ofgem allows a special factor adjustment for the additional costs associated with the legacy design of SP Manweb's network.[30]

Ergon has a number of legacy network design factors which warrant a company-specific factor considering from the AER. We discuss these in Section 5.3 below.

When costs are unexplained or explained poorly by cost drivers

There are some costs that are considered by Ofgem to be inappropriate for benchmarking because they are not adequately explained by the cost drivers that are presently available for inclusion in a benchmarking model. Examples of such costs include.

- **Critical national infrastructure (CNI).** In the UK, projects that are classified as 'CNI category 3' are eligible for ex-ante funding in accordance with the government's Physical Security Upgrade Programme. Ofgem therefore allows the DNOs their submitted costs for these sites. The classification of CNI projects is determined by government decisions, rather than the network itself based on an assessment of network needs and this can lead the requirement to deliver a higher volume of work at a higher specification than is necessary for companies not required to deliver a CNO project. Costs associated with CNI projects are therefore excluded from Ofgem's benchmarking in RIIO-ED1.
- **Wayleaves.** Wayleaves (similar to 'easements' in Australia) permit the GB DNOs to install electric lines and associated equipment on, over or under private land and to have access to that land (e.g. to conduct maintenance work). The landowner is compensated in the form of wayleave payments. Ofgem's treatment of wayleaves has evolved over time. At DPCR5, it decided to exclude wayleaves from its main benchmarking and submit these costs to separate scrutiny as it was felt the causes of differences in wayleaves would not be well explained by the proposed cost drivers. At ED1, Ofgem has included wayleaves as a controllable cost within its modelling, reflecting the desire to include more costs within its benchmarking wherever possible, and in the light of improvements in the information available.

Further examples of costs subject to bespoke treatment under Ofgem's benchmarking approach include property costs and Information Technology and Telecoms (IT&T) costs. Ofgem recognises that property costs may be very specific to the DNO, dependent on its present ownership, historic ownership and any past rationalisation of the work force and costs. While such costs are controllable, and require some form of scrutiny, they do not naturally lend themselves to simple comparison against some high level metrics of network size.

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30 Ofgem (2014), 'RIIO-ED1: Final determinations for the slow-track electricity distribution companies – business plan expenditure assessment', November, Appendix 9.

Similar reasoning applies to IT&T, where different companies have different operational needs governed by the specifics of their network and how they manage their workforce. IT&T can also tend to be lumpy, with intermittent systems replacement expenditure overlaying more regular maintenance expenditure. Again, these costs do not lend themselves naturally to simple comparison.

In both cases Ofgem has tended to rely on external expert assessment of whether company plans and planned expenditure are reasonable.

A number of Ergon's costs are unlikely to be explained by the cost drivers included in the AER's benchmarking. These include the costs associated with Ergon's need to meet regulatory obligations, and costs associated with severe weather and unique environmental conditions in Queensland. We discuss these in section 2 and in section 5.3 below.

When significant difference between history and forecasts

For ED1 Ofgem has concentrated on benchmarking company plans. However, prior to ED1 Ofgem made use of a benchmark of historic costs to inform its efficiency assessment and its view of efficient future allowances. Ofgem recognised however that benchmarking historic cost to inform future allowances would not be appropriate if the costs included to determine the relative efficiency in the historic period are not likely to be reflective of costs that the DNOs will incur in the future, e.g., if the volume of activity required could reasonably be expected to change materially from historic run rates.

For example, Ofgem's transmission connection point charging (TCP) methodology changed in GB from DPCR5 to RIIO-ED1. Ofgem therefore excluded these costs from its benchmarking in RIIO-ED1. Ofgem has also sought to develop more sophisticated forward looking modelling of asset replacement volumes, allied with benchmarking of unit costs, in order to pick up network investment cycles that drive the necessary volume of work.

We recommend that the AER investigate whether these factors are relevant to the Australian DNSPs.

When costs are uncontrollable

Uncontrollable opex generally relates to items such as business rates licensee fees, and taxes, which are determined and levied on companies in a way entirely (or almost completely) beyond their control.

If such costs vary across regions and are included in the benchmarking analysis, this will confound like-for-like comparisons between networks. For instance, the DNSPs that face the highest exogenously-imposed taxes and levies will be found less efficient than those facing the lowest taxes and levies, even though these costs are beyond the influence of the networks. For this reason, Ofgem has typically sought to identify and remove such costs from its benchmarking, because it considers that only those costs that are within the DNOs' control should be subject to efficiency assessments; there is no merit in placing any financial incentive on uncontrollable costs as by definition it cannot encourage any efficiency savings.. If a company cannot control a cost, placing a financial incentive on it in relation to that cost will simply increase risk (exposing it to a cost risk it cannot manage). Uncontrollable costs are therefore typically passed through to customers.

We understand that the AER has not excluded uncontrollable opex items from its measure of Network Services opex. In fact, to our knowledge, the AER has not gone through a process to identify and distinguish between costs that are controllable and costs that are uncontrollable. As uncontrollable opex items may not be explained by increases in scale over time and the magnitude of uncontrollable opex may be significantly different between DNSPs, the AER should exclude uncontrollable costs from its benchmarking analysis.

When costs are outside the regulatory control

Some costs incurred by the GB DNOs are excluded from Ofgem's regulatory control, and recovered directly from customers. These are the costs associated with Ofgem's activities which are within the potentially competitive element of the market, like customer connections and metering, for example.

The connections market in GB is contestable and independent connection providers undertake a significant proportion of new connections, although this proportion varies across regions This means that not all customer connections in GB are provided by the GB DNOs. The costs of providing customer connections are also very largely recovered directly by the GB DNOs from the connecting customers (not from the general body of customers through network charges), and are therefore excluded from the regulatory control.

Similarly, the GB DNOs are not responsible for all metering activities. In GB, there has been full competition since 1998 for meter operators, who are responsible for installing and maintaining electricity and gas meters. The costs of any metering services provided by the GB DNOs are also recovered directly from customers, and are therefore excluded from the regulatory control.

We note that the exclusion of costs related to services provided outside the ring fence of the regulated business can throw up a range of related challenges for benchmarking, related to how shared and common costs (head office/back office support) are allocated across regulated and non-regulated activities. Ofgem has developed granular rules to manage this process. We discuss this further in the following subsection.

When there are differences in cost allocation principles

Notwithstanding the need to ensure that all relevant cost drivers are controlled for in some way, there is also a need to ensure that benchmarking is undertaken on data that is consistent in terms of its basis of preparation. This requires the adoption of common reporting procedures to ensure that costs are allocated in the same way by all members of the sample. Should this not be the case, then any partial or disaggregated benchmarking may be confounded by different cost allocation procedures. This concern is clearly particularly important where reliance is placed on opex only assessment, as a failure to allocate costs commonly as between opex and capex may bias efficiency analysis.

When in the past Ofgem has had concerns with the data submitted by the GB DNOs, it has made a number of adjustments to bring the data on a consistent basis for its benchmarking analysis. Ofgem has then learned from this experience at a review, and used it to improve the specificity of its reporting guidelines over time.

In the early stages of Ofgem's experiments with regulatory reporting and benchmarking at DPCR3 and DPCR4, Ofgem found it necessary to make several cost adjustments to account for apparent differences in cost allocation methodologies in the data.

- **Adjustments for cost allocation between opex and capex.** DPCR4, Regulatory policy allowed for considerable flexibility in defining the division between opex, non-operational capex and network capex. For example, the repair of underground cables and meter recertification costs had been variously defined by the DNOs. In addition, some items of non-operational capex, e.g. expenditure on IT systems, had been provided by third party contractors rather than by the DNOs themselves, further distorting the raw data provided by companies. As a result, Ofgem needed to reclassify several items from network capex to opex (e.g. repairs, metering and non-operational IT depreciation) and remove project depreciation IT from opex.
- **Need to assess some cost categories separately altogether.** In DPCR4, one of the main areas of discrepancy in cost allocation across the DNOs was in their allocation of fault costs (i.e. the costs of repair and restoration after a fault), between opex and capex. This is a substantial category of costs for most GB DNOs, and discrepancy in cost allocation had a significant impact on Ofgem's benchmarking results. To overcome this drawback, Ofgem assessed fault costs separately at the start of DPCR4.
- **Need to normalise the allocation of overhead costs.** The majority of the GB DNOs (with the exception of Electricity North West) belong to ownership groups that own and operate multiple DNO licences. The DNO ownership groups incur overhead costs, including business support costs and closely associated indirect costs at the group level, rather than at the licensee

level. The allocation of these overhead costs to individual licensees may be sensitive to cost allocation principles, implying that efficiency results may be similarly sensitive to allocation decisions that may in part be arbitrary. This remains an issue even in the latest regulatory control (RIIO-ED1), where Ofgem tested the sensitivity of the results of its benchmarking analysis to differences in these cost allocation principles, and proposed to make a special factor adjustment if necessary.

As noted above, similar issues also arise in respect of cost allocation between regulated and unregulated businesses, such as each DNO's connections business.

When there are atypical costs associated with severe weather

In the past, when Ofgem depended on a cross section of data for a given year, we understand that Ofgem examined those data to assess whether it was necessary to strip out costs that might reasonably be deemed as exceptional, having arisen due to an extreme weather event. Since no two companies will have identical experiences in any given year, atypical weather may well drive a difference in measured efficiency that arises for purely temporary reasons..

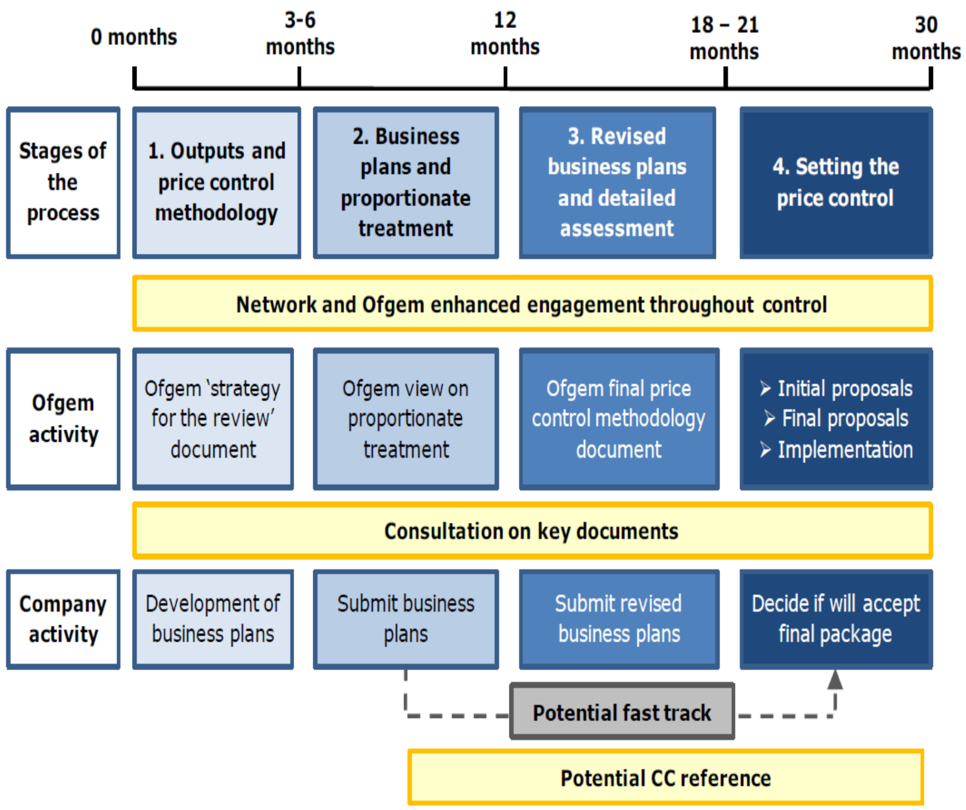
Now that Ofgem makes use of panel techniques, it is less concerned to make such an adjustment. Over a run of years, given the comparative homogeneity of weather across GB, most companies will experience a range of weather including a number of extreme events. Since no single year ultimately determines the regulator's view of efficiency, there is no need to smooth out every single year, and each company will be assessed reasonably fairly on average and over time.

Such an approach is only reasonable if companies have very similar exposure to extreme weather. In Section 5.2 below we set out the reasons why the Norwegian regulator adopts a different approach.

5.1.3 Process followed by Ofgem when determining special factor adjustments

Ofgem begins to engage the network companies on the issue of benchmarking and any need for special factor adjustments around 30 months before its final decision is due. Ofgem's regulatory timetable is summarised in Figure 33 below.

Figure 33. Ofgem's regulatory timetable



Source: Ofgem RIIO handbook

Ofgem describes its own regulatory process in four 'stages':

- **Stage 1.** This stage begins with an open letter to the industry and other stakeholders, signalling that it is commencing work on the price control, and setting out how it intends to run the process over coming months and years. The aim of this stage is to set the timetable for the review, understand the key issues, and set the parameters for the price control, while engaging with stakeholders throughout. Ofgem formulates a high-level plan for benchmarking at this stage, following workshops with the DNOs to invite views on its benchmarking methodology and which special-factor adjustments may be relevant. At the end of this stage, Ofgem issues its guidance on business plan requirements to the network companies, and publishes its 'Strategy for the review' decision document.
- **Stage 2.** At this stage, the DNOs develop their business plans, based on the guidance issued by Ofgem. They also complete their last regulatory reporting pack before the review commences, containing the last year of actual on which Ofgem will be able to rely. As Ofgem's data reporting templates are

detailed and disaggregated, the DNOs are required to quantify a number of costs that may be subject to special factor adjustments through the data template itself (including non-controllable costs such as taxes and levies). At ED1 Ofgem placed more onus on the companies to bring forward and justify proposals for company specific adjustments. The DNOs therefore included their own requests for any company-specific factors (like sparsity, legacy network design, etc) in their business plans, based on bespoke calculations made on a case-by-case basis. During this stage, Ofgem publishes the results from its first attempt to apply benchmarking to the data submitted by the GB DNOs (a methodology paper for comment). Ofgem comments on the DNOs' requests for special factor adjustments at this stage. At the end of this stage, Ofgem decides whether any of the business plans submitted by the DNOs are worthy of fast tracking. DNOs not fast tracked proceed into the slow track phase, where a more granular assessment of their proposals ensues.

- **Stage 3.** Ofgem's objective for this stage is to finalise business plans for the network companies and confirm its methodology to be used to set the price control for slow track firms. Based on feedback provided by Ofgem on their fast track business plans, the DNOs have the opportunity to revise their business plans before Ofgem's final assessment is taken. This includes the potential to revise their own estimation of the special factor adjustments that are relevant for benchmarking. Ofgem concludes its price control methodology document at the end of this stage.
- **Stage 4.** During this final stage, Ofgem implements its methodology through initial and final proposals for the network companies, in accordance with the final price control methodology from stage 3. The network companies are given the opportunity to respond to both Ofgem's methodology document from Stage 3, and its initial proposals from Stage 4. At this final stage substantial changes in process are rare, but remain possible should clear evidence of a need to revise approach emerge.

The process is highly iterative, and DNOs have extensive opportunity to engage with Ofgem on the issue of special factors.

5.1.4 Magnitude of special factor adjustments

Ofgem does not publish the full details of the magnitude of its special factor adjustments. However, below we summarise the information that Ofgem published in the two more recent regulatory reviews.

Costs excluded from Ofgem's opex benchmarking in DPCR5

The categories of costs excluded from Ofgem's opex benchmarking analysis in DPCR5 is summarised in Table 12 below.

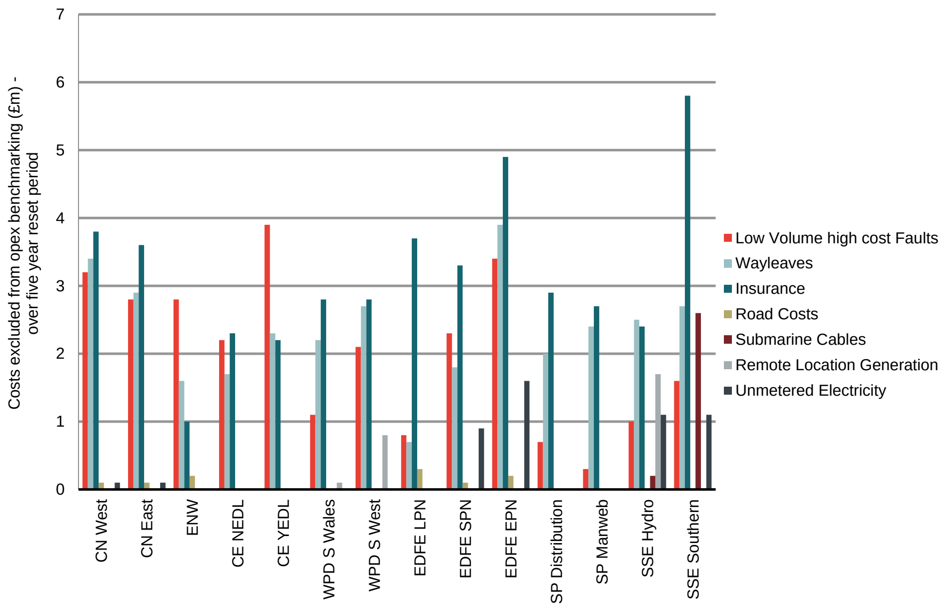
Table 12: Operational Costs excluded from the regression analysis in DPCR5

Initial Proposals	Final Proposals
Wayleaves	Wayleaves
Submarine cables	Submarine cables
Low volume high value faults	Low volume high value faults
Non QoS faults	Non QoS faults
Remote location generation	Remote location generation
Substation electricity	Substation electricity
Terrorism insurance	Terrorism insurance
Urban specific costs	Urban specific costs
Pressure assisted cables	Pressure assisted cables
3rd Party damage recovery	3rd Party damage recovery
Dismantlement	Dismantlement
Severe Weather 1-in-20 event	Severe Weather 1-in-20 event
Property rents	Property Management
	IT and Telecoms

Source: Ofgem (2009), 'Electricity Distribution Price Control Review Final Proposals - Allowed revenue - Cost assessment', 07 December, page 67, Table 4.10

The magnitude of these costs is illustrated in Figure 3 below.

Figure 34: Operational Costs excluded from the regression analysis in DPCR5 (£m)



Source: Ofgem (2009), 'Electricity Distribution Price Control Review. Methodology and Initial Results Paper', 08 May, page 25, Table 14.

Costs excluded from Ofgem's totex benchmarking in RIIO-ED1

The categories of costs excluded from Ofgem's totex benchmarking analysis in RIIO-ED1 is summarised in Table 13 below.

Table 13: Costs excluded from Totex benchmarking

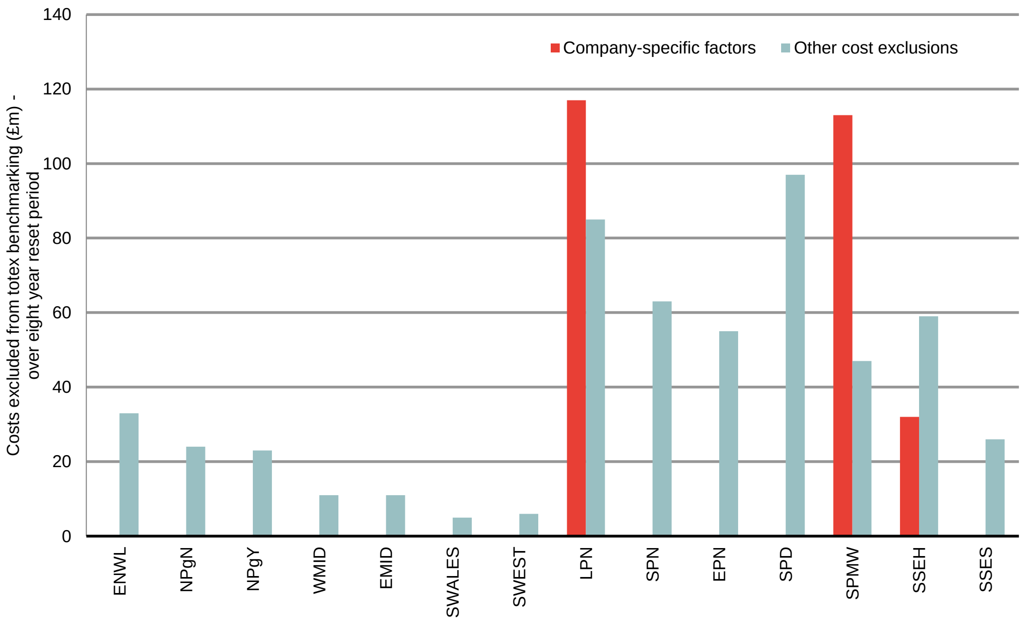
Initial Proposals	Final Proposals
Flood mitigation	Transmission connection point (TCP) charges
Bt21c	Critical national infrastructure (CNI)
Losses and environmental	Rising and lateral mains (RLM)
Operational and non-op capex IT&T	Improved resilience
ETR 132 tree cutting activity	Quality of service (QoS)
Wayleaves	Smart meter roll out (including smart meter call out costs)
Third party connections	New streetwork costs

Source: Ofgem (2014), 'RIIO-ED1: Final determinations for the slow-track electricity distribution companies. Business plan expenditure assessment', 28 November, page 50-51, Paragraph 4.49 and 4.51.

The magnitude of these costs is illustrated in Figure 35 below.

Special factor adjustments

Figure 35: Total costs excluded from the totex regression analysis in DPCR5 (£m)



Source: Ofgem (2009), 'Electricity Distribution Price Control Review. Methodology and Initial Results Paper', 08 May, page 25, Table 14.

We note that it is not straightforward to compare Ofgem's cost exclusions across its different regulatory controls. This is owing to the fact that Ofgem's approach to benchmarking has changed significantly over time. For example, the cost exclusions shown in Table 12 and Figure 34 above relate to Ofgem's benchmarking of operating costs only in DPCR5. On the contrary, the cost exclusions shown in Table 13 and Figure 35 above relate to Ofgem's benchmarking of totex (which includes both opex and capex) in RIIO-ED1.

5.1.5 Methods used to quantify adjustments

Ofgem assesses special factor adjustments on a case-by-case basis. The GB DNOs make their special factor requests to Ofgem on the basis of their own bespoke calculations. There is no single best approach to making these calculations, and they differ between DNOs and between different types of special factors. Some types of special factor adjustments, like for uncontrollable costs (like rates, levies and taxes), can be quantified easily and can simply be excluded. For quantifying company-specific factors, a number of approaches may be adopted:

- **Comparisons between different parts of the same network.** The DNOs can compare one part of their network against another part of their own network where the factors differ. For example, SP Manweb compares its own interconnected network (in the urban Manchester region) with its own radial network (in the more rural areas in which it operates) to quantify its special factor request for its legacy network design.

- **Comparisons of two networks within the same ownership group.** The majority of the GB DNOs belong to ownership groups that include multiple DNOs. In this case, Ofgem compares two networks that have common ownership but operate in different circumstances (For example, EDFE LPN is compared against EDFE EPN to quantify the impact of customer density on costs)
- **Comparisons over time**. Another approach is to compare the same network over time as circumstances change (i.e. make a 'before' and 'after' comparison of costs)

In RIIO-ED1, these comparisons were detailed, complex, and based on highly disaggregated data. We provide two case studies in Box 2 and Box 3 below.

Box 2: SSE Hydro special factors in RIIO-ED1

In RIIO-ED1, SSE Hydro received a special-factor adjustment for the following sparsity-related opex factors:

- Remote depots property costs – higher property related costs owing to more deports per customer (£65k pa)
- Depot staff costs - higher staff costs compared with other DNOs due to the need for 71 additional staff, and the remote location, geography and terrain of SSE Hydro's network (£2.67m pa).
- Travel costs
  - Higher travel times to remote locations, resulting delays, the need for additional overnight accommodation for staff, higher diesel fuel costs on the islands than on the mainland, and long travel distances increases the amount of fuel bought. (£210k pa)
  - Need for specialist staff to visit island locations to perform work that local staff cannot do. Need for overnight accommodation, owing to the fragmented nature of the west and north coast with many islands, both for routine and fault work. (135k pa)
  - Need for helicopter companies which allow their remote networks to be assessed from the air following a storm, to identify points of damage (£80k pa)
- Weather/climate: Need to transfer additional manpower to the islands prior to forecast storm events to ensure that there are sufficient resources to deal with potential faults. On average there have been 2 events p.a. where staff has been deployed, but the event has not materialised, with a total estimated cost of (£100k pa).

Source: Ofgem

Box 3: SP Manweb special factors in RIIO-ED1

- In RIIO-ED1, SP Manweb received a special-factor adjustment for the following sparsity-related opex factors:
- 33kV opex:
  - 33kV circuit breakers are not a feature of traditional network primary substations, the inspection and maintenance of SP Manweb's assets therefore requires an additional regional cost (£2.2m over ED1).
  - Higher cost of repairing pilot circuits on its 33kV interconnected network compared with the cost of repairs on its radial SPD network (£2m over ED1).
  - fault repairs on rented 3rd party pilots (£1.4m over ED1).
  - 33kV cable faults on a higher UCI for repairs compared to SPD, due to the higher fault levels on an interconnected network (£0.6m over ED1)
- HV opex - additional I&M costs associated with 11kV interconnected network, because the interconnected network requires HV circuit breakers at each secondary substation to allow for the application of its unit protection policy (£2.1m over ED1)
- LV opex - additional costs for LV fault location, because of the technical nature of its interconnected networks (£1.8m over ED1)

Source: Ofgem

5.2 NVE's approach in Norway

There are over 130 electricity distribution network companies (DSOs) in Norway. This large number of companies makes very highly tailored regulation of the kind pursued by Ofgem difficult. It will be hard for any regulator to gain a close knowledge of the specific circumstances that pertain to each company in the sample, making it more necessary to move towards a top down, more mechanistic style of benchmarking. However, having 130 companies also brings with it the benefit of a large sample. This increases the likelihood of having within the sample several companies with the same or similar circumstances ensuring the existence of reasonably close peers for all. This is helpful because, unlike in the UK, there are significant differences in climate, geography and environment across the different regions in which the DSOs operate in Norway, which are likely to affect costs significantly. The Norwegian regulator (NVE) acknowledges that these factors are important and controls for them in its modelling. Furthermore, NVE also attempts to test for outliers in its analysis.

Reflecting their circumstances, there are two main stages to NVE's analysis. In stage one, it benchmarks total costs taking account of eight cost drivers and using a Constant Returns to Scale DEA analysis. In stage 2, it corrects these DEA efficiency scores for differences in environmental factors are considered to be outside of management control. We describe NVE's two stage approach in more detail below.

5.2.1 Stage 1: DEA analysis

The first stage towards the determination of revenue caps is the comparative benchmarking of the DSOs using DEA. The DEA analysis conducted by NVE uses only one input, total cost. In the previous regulatory control period in Norway, NVE's first stage DEA model included eight outputs. The output variables chosen by NVE reflect not only not amount of output each company serves, but other also factors that have a significant impact on company costs, such as geographic factors and factors reflecting network structure and size:

- subscriptions, not including vacation homes;
- subscriptions for vacation homes;
- delivered energy;
- high voltage lines;
- network stations;
- forest;
- snow; and
- wind / coast.

NVE assumes a Constant Returns to Scale (CRS) frontier. Using this benchmarking model NVE determined DEA efficiency scores for each of the DSOs.

NVE also attempts to test for outliers in its analysis. NVE's analysis is based on DEA, which allows for efficiency scores above of 100% (super efficiency). NVE acknowledges that high efficiency scores may in some cases be due to outlier effects rather than real efficiency. In an attempt to mitigate the impact of outliers, NVE allows only companies that are super-efficient on average over the last four years to keep their super-efficient scores. This means NVE runs two separate DEA analyses. For example, once with 2010 data and a second time with averaged data for 2006-2009. Companies that were over 100% efficient in 2010, but were not super-efficient when compared to the 2006-2009 are capped at 100%. Companies that are super-efficient both relative to the 2006-2009 dataset and the 2010 dataset are allowed to keep their super-efficient score from the 2006-2009 analysis. These scores are then carried on to the second stage where they are corrected for the three environmental factors.

Stage 2: Correction for environmental factors

NVE's efficiency scores determined in stage one control for eight output variables. In stage 2, NVE adjusts these efficiency scores to take account of further environmental factors outside of management control in order to limit the extent to which final efficiency scores may pick up differences in company circumstances.

The second stage of NVE's analysis is designed to correct the DEA efficiency scores for three environmental factors, Interfaces, Islands and Distributed Generation (DG). This is done by regressing the efficiency scores from stage one on the environmental factors in stage two. A coefficient is calculated for each of these variables using a panel data model, as in the equation below.

$$Efficiency\ scores =$$
$$\beta_1 * Island\ connections$$
$$+ \beta_2 * Transmission\ interfaces$$
$$+ \beta_3 * Distributed\ generation$$

These coefficients are then used to calculate an environmental factor correction (EFC) for each of the companies. The EFC determines how much of a disadvantage (in units of efficiency score) each grid company suffers for its amount of Islands, Interfaces and DG. This adjustment makes the efficiency scores from stage one more comparable, or so that they correspond to a common level of environment.

It is worth noting that NVE also moderates the results of its benchmarking by setting allowed cost in line with 40% of the companies' submitted costs, and 60% of the "efficient" benchmarked costs derived from its model.

Given the variation in climate and terrain across Australia, it is almost certain that the AER will need to take account of such factors, as NVE has considered necessary in the case of Norway. A two stage estimation of the kind adopted by NVE may be possible, but the ability to do so will be limited by sample size, AER has available to it one tenth of the data available to NVE. AER may need to adopt a hybrid of the Ofgem approach (which involves more direct and bespoke scrutiny of the companies), but taking account of a broader range of factors, as does NVE.

5.3 Special factors relevant to Ergon

It is clear from the discussion above that regulators in the UK and Norway undertake a significant amount of effort to ensure that their benchmarking analysis is conducted on a like-for-like basis. In comparison, the AER has failed to take into account, in its benchmarking analysis, the vast latent heterogeneity between DNSPs. In doing so, the AER has mistaken genuine and intrinsic differences in operating circumstances between networks in Australia with managerial inefficiency. This, in turn, has produced distorted benchmarking results, which led the AER to conclude erroneously that many of the DNSPs, including Ergon, are materially inefficient.

In Section 2, we presented a range of descriptive analysis to demonstrate that Ergon faces very unique operational circumstances that mean that its costs cannot be compared easily with most other DNSPs in Australia. Ergon has submitted to the AER that the sources of these differences that make its circumstance unique include:

- the vast and sparsely-populated region served by Ergon;
- the characteristics of Ergon's network, including its ownership of sub-transmission assets, an extensive SWER system, and connection to volume of small-scale generation;
- its regulatory obligations with respect to vegetation management, safety legislation and environmental levies;
- the harsh weather and environmental conditions that are unique to Queensland; and
- differences in Ergon's cost allocation practices relative to the other DNSPs.

In Table 14 below, we summarise these factors and their impact on opex, drawing on a number of submissions that Ergon has provided to the AER to explaining the ways in which its operating circumstances differ significantly from most other DNSPs in Australia.

Table 14: Summary of special factors relevant to Ergon

Special factor	Category of special factor	How does the special factor affect opex?
Sparsity	Customers dispersed over Ergon's large service area	More assets are needed to serve customers as they become more dispersed (higher volume of overhead assets, greater number of transformers and associated equipment including switchgear, fuses, etc), increasing both capital and operating costs as sparsity increases. For example, Ergon has higher costs associated with inspections and maintenance, transport and travel, fault finding and patrolling, wayleaves and easements and higher property-related costs.
Network configuration	Ownership of sub-transmission assets	Ergon provides an additional subtransmission service that many other DNSPs in Australia do not. Subtransmission systems require larger and more expensive infrastructure to operate when compared to distribution systems, owing to the higher voltages and potential fault energy involved.
	Single Wire Earth Return (SWER) techniques	Higher opex associated with periodic inspections and repairs required under regulatory obligations to ensure that earthing systems operate safely. Higher transportation costs owing to the inherent long travel distances involved.
	Embedded generation	The majority of solar installations on Ergon's network do not control terminal voltage and their combined impact is resulting in an increasing level of voltage management complaints.
Weather	Cyclones	Ergon’s coastal assets are designed for a prudent level of resilience for cyclone activity. For example, pole structural strength for north Queensland coastal areas are designed to withstand wind pressures of the mid-level Category 3 cyclone.

	Flooding	Flooding results in travel restrictions and prevents Ergon from performing many of its inspection and maintenance tasks, undermines assets which then requires maintenance and repair work, destroys access tracks which then requires track maintenance and repair, limits and prevents operational switching which typically extends outage durations and extents; submerges assets which reduce asset life.
	Rainfall and high temperature	Rainfall and high temperature contribute to significant tree and vegetation growth, with many tropical plants growing several metres annually, giving rise to higher vegetation management costs for Ergon. High rainfall also accelerates the degradation of wooden poles, particularly in the presence of high temperatures, which increases the maintenance and replacement rates of poles. Poletops in high rainfall tropical areas are inspected via the Elevated Work Platform (EPV) due to the accelerated deterioration of the crossarms from fungal attack, causing loss of structural integrity and failure.
	Drought	Drought reduces deep soil moisture, which has a significant impact on earthing system efficacy. This gives rise to higher opex associated with inspecting and testing earthing systems (as required under regulatory obligations) to ensure safe step and touch potentials for the public.
Differences in regulatory obligations	Vegetation management	Local councils perform a large proportion of vegetation management in some Australian States. In contrast, Ergon performs this function alone across its whole operating region.
	Safety legislation	Ergon has the obligation to operate under Queensland Electrical Safety legislation. The associated regulations and Codes of Practice impose some unique obligations on Queensland DNSPs, which are not faced by the DNSPs outside Queensland.

Special factor adjustments

	Environmental levies	Ergon pays levies to the Electricity Safety Office (ESO) and the Queensland Competition Authority (QCA). These costs are uncontrollable and should therefore be excluded from the AER's benchmarking analysis.
Environment and terrain	Cultural heritage	Ergon's cultural heritage imposes additional management and operational costs necessary to ensure appropriate management, including staff training and awareness, special alert and management processes and additional operational precautions.
	Biological precautions	Ergon's assets are periodically subject to various biologic precautions when travelling through and between these regions. Ergon is required to wash down all of its trucks and vehicles to prevent the spread and contamination of weeds, pests and other diseases.
	Bushfires	Bushfires in the northern and western parts of Queensland tend to be short, fierce events due to prevalence of turpentine bushes and spinifex which burn rapidly and almost completely.
	Termites	Mastotermes Darwiniensis termites in Queensland can destroy a typical Ergon pole within two or three months. Ergon's Opex includes allowances to identify and treat termite infestations near or within poles as part of its inspection process.
	Asbestos management	Ergon has opex associated with the removal of friable asbestos from commonly accessed assets, and safe management of the remainder. Ergon long term goal is to remove all asbestos from its assets.
	Contaminated land management	Ergon has "inherited" from various legacy organisations some old generation sites that contain contaminated soil. Ergon incurs opex for progressively improve and remediate these sites.
Cost allocation	Capitalisation policy	Unlike most other Australian DNSPs, Ergon's capitalisation policy accounts for the vast majority of its IT expenses as Opex, due to the provision of IT services to it by its 50% joint-venture provider, SPARQ Solutions. With the exception of Energex, we understand from Ergon that other DNSPs typically own their IT assets.

Source: Frontier Economics

Special factor adjustments

Of the factors summarised in Table 14 above, three are likely to have a particularly material impact on Ergon's opex.[31]

- **Sparsity.** Ergon is the largest DNSPs in the AER's sample of 13 DNSPs. Ergon serves an area (1,698,100 km²) significantly greater than the land area of France (547,700 km²), the UK (241,900 km²) and Spain (498,800 km²) combined and nearly twice the land area of Ontario (917,741 km²). Ergon serves over 97% of Queensland by land area, and its customers are also sparsely dispersed across its service region. Owing to these reasons, we recommend that the AER consider the case for making a sparsity-related company-specific special factor adjustment for Ergon. As discussed in Section 5.1 above, Ofgem has recognised that need for sparsity-related company-specific factor adjustment in the UK, have made an adjustment for SSE Hydro's costs in every regulatory control period since 2000.

  The size of Ergon's area of geographic coverage, combined with the need to provide a level of reliability throughout its service delivery area involves logistics associated with stores and spares management. Ergon need to maintain sufficient quantities of basic components, such as poles, crossarms, service cables, fuses, insulators, bolts, etc. Unlike other Australian DNSPs, Ergon maintains multiple warehouses at various locations around Queensland to mitigate the issues and risks involved with transport and logistics.

- **Network configuration.** Ergon has significantly higher opex costs relative to its comparator DNSPs owing to its unique network characteristic, including its ownership of sub-transmission assets, an extensive SWER system, and connection to volume of small-scale generation. As these costs are largely unique to Ergon and a small number of other DNSPs, we recommend that the AER investigates the case for making company-specific adjustments for these factors.

- **Weather and terrain.** There are significant differences across the different Australian regions with respect to weather and terrain. This is an important consideration in Norway, as discussed in Section 5.2 above. Ergon incurs significant costs associated with severe weather and unique environmental conditions in Queensland. Ergon's severe weather conditions increase the likelihood of outages on Ergon's network and lead to higher opex associated with faults and emergency response operations. In addition to the factors discussed in the table above we understand that to enable Ergon to safely operate in its extreme conditions, its network operation functions also require a large amount of deliberate duplication.

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31 That is not to say that the other factors identified in Table 14 are not material. Those factors will require further investigation by the AER.

Ergon needs to maintain a large number of duplicate network operations control centres which are manned 24/7. The duplication is necessary to reduce the risk of control centre failure during natural disaster situations (for example, during cyclones).

5.4 Comments

It is clear that there are several special factors that are likely to have a material impact on Ergon's costs. As regulators in Europe have recognised, it is usually not possible to account for all of these factors properly within a necessarily limited benchmarking model (such as has been employed by the AER). However, a proper benchmarking analysis should take these special factors into account in some way in order to avoid identifying incorrectly genuine operational differences between networks as managerial inefficiency. In our view, the benchmarking analysis that the AER has produced to date is incomplete because it fails to account adequately for the very large and evident differences in circumstances between networks.[32]

EI's/AER's only attempt at accounting for (a very limited number of) special circumstances in the NSW/ACT Draft Decisions involved increasing the input use of the top quartile DNSPs by 10% for the NSW networks and 30% for ActewAGL. As we argued in our report for Networks NSW, these adjustments were arbitrary and based on a very incomplete exploration of possible differences between DNSPs. They were also wholly inadequate as they still gave rise to implausibly large reductions to base year opex levels (i.e. between 13% and 45%). The very significant issues we have identified in the preceding sections all point to very material heterogeneity across the Australian networks, which has not been controlled for by the AER. There is no reason to suppose that a 10% tolerance captures these adequately.

The AER's failure to allow, within its benchmarking methodology, an explicit step to account for special factors suggests strongly that its application of benchmarking falls well short of best practice.

We recommend that the AER considers the case for making a special factor adjustment for these costs. As there is no single best approach for making a special factor adjustment, the AER would need to consider these on a case-by-case basis. We note however that there may be insufficient time within the present regulatory timetable to quantify the required special factor adjustments,

32 EI's/AER's only attempt at accounting for (a very limited number of) special circumstances involved increasing the input use of the top quartile DNSPs by 10% for the NSW networks and 30% for ActewAGL. As we argued in our report for Networks NSW, these adjustments were arbitrary and wholly inadequate as they were based on a very incomplete exploration of possible differences between DNSPs.

as the AER will need to account not just for Ergon's special factors but also for any special factors that relate to the remaining 12 DNSPs. The process of identifying, understanding and quantifying special factors is an iterative one that requires time for proper engagement between the regulator and the networks. Furthermore, it is very likely that data and other information needed to assess and quantify the factors fully does not exist readily, and so will need to be compiled. This will require time.

This means that the quantification of the impact of special factors is a task for the medium-term. AER should develop a process to ensure the necessary engagement with the DNSPs in time for the next review.

Appendix A – Mapping of Postal Areas to DNSP service areas

Data availability

A combination of online lookup tools, maps, and self-reported data were used to match DNSPs in the NEM to postcodes. Only one distributor, Energex, made available publically a list of its entire distribution area. Other DNSPs such as Ausgrid, AusNet Services, CitiPower and Powercor, Jemena, and United Energy provide online lookup tools which allow customers to find the DNSP responsible for a given postcode. We also utilised a DNSP lookup tool provided by Energy Australia on its website. See Table 15 below.

Table 15: Online lookup tools used to collect DNSP postcode data

Source	URL address
Ausgrid	https://www.ausgrid.com.au/Common/About-us/Contact-us/Our-distribution-area.aspx
AusNet Services	http://www.ausnetservices.com.au/Listing/Supply+Interruptions/Postcode+Search.html
CitiPower and Powercor	https://www.powercor.com.au/about-us/electricity-networks/postcode-network-locator/
Jemena	http://jemena.com.au/outages/find-my-distributor.aspx
United Energy	http://uemg.com.au/customers/your-electricity/electricity-outages.aspx?postcode=3000
Energy Australia	https://secure.energyaustralia.com.au/FaultServicesLocator/

Source: Frontier Economics

In a number of instances, the DNSPs provided information not just on their own postcode coverage, but also the coverage of other DNSPs. These online lookup tools did not provide comprehensive coverage of all NEM regions. For instance, Energy Australia's lookup tool covered South Australia, Victoria, New South Wales, and Queensland, while lookup tools provided by Ausgrid, AusNet, CitiPower and Powercor, Jemena, and United Energy only covered Victoria (see Table 16).

Table 16: Postcode coverage of online lookup tools

Source	Postcode coverage of lookup tools
Ausgrid	2000 – 3000 (NSW only)
AusNet Services	3000 – 4000 (VIC only)
CitiPower and Powercor	3000 – 4000 (VIC only)
Jemena	3000 – 4000 (VIC only)
United Energy	3000 – 4000 (VIC only)
Energy Australia	2000 – 6000 (NSW, VIC, QLD, ACT, SA)

Source: Frontier Economics

Different lookup tools returned data in different ways. For example, Jemena's tool outputted all distributors for a given postcode, whereas Ausgrid's tool would only indicate whether a given postcode was part of its service area. As discussed below, the various lookup tools did not always provide a consistent mapping of DNSPs to postcodes.

In addition to online lookup tools, maps of distribution areas were utilised. In instances where the abovementioned methods resulted in significant ambiguity, distributors were contacted directly.

Data collection and processing

Our main method for matching DNSPs to postcodes was to extract relevant data from the online lookup tools provided by DNSPs and retailers. The name of the distributor (if one existed for the postcode queried) was extracted from the webpage and written to a .csv file. It should be noted that there were instances of the postcodes returning a 'no match' error message when a match did in fact exist. This was likely due to the web page auto-refreshing at the instant the program attempted to extract data from the webpage. To address this issue several passes were made to ensure that all relevant postcodes were captured. These passes involved identifying postcodes for which a 'no match' error message was displayed and then running the program again for those postcodes specifically. The process was repeated until there was confidence that the final list of 'no match' error messages were valid.

The search range for each online lookup tool was customised. For example, it was known that United Energy's tool would not return information for postcodes outside Victoria. Therefore it was only necessary to search for postcodes in the range 3000 to 3999. Table 16 summarises the search ranges we employed.

Appendix A – Mapping of Postal Areas to DNSP service areas

Problems

We found that no distributor matches could be made for two areas in the NEM: ACT[33] and Tasmania. However, as there is only one DNSP in each of these States (i.e. ActewAGL and TasNetworks, respectively), it was straightforward to allocation ACT and Tasmanian postcodes.

More problematic however were the inconsistencies observed between data sources. Different lookup tools sometimes provided contradictory information about the distributor responsible for a particular postcode. Furthermore, in areas where the distribution areas of two or more DNSPs intersect in a postal area, the lookup tools would identify multiple DNSPs serving the same postcode. In such circumstances, different DNSPs may share responsibility for those postcodes and so should be allocated partially to a given postcode. However, the data resulted in some double-counting as multiple DNSPs were recorded as serving the same postcodes.

There are inherent limitations associated with using data based on postcodes. Postcodes do not have defined geographic boundaries, and also do not cover the entire country. The Australian Bureau of Statistics (ABS) addressed the first issue by constructing Postal Areas (POAs), which attempt to approximate postcodes using a defined set of rules.[34] When the rules are violated a POA is not assigned to a postcode. We identified 83 postcodes, which returned distributor matches when searched for using Energy Australia's database, did not have a corresponding POA. Consequently Census data on area, population, and number of dwellings were unavailable for these locations.

Solutions

We had to make certain assumptions when addressing inconsistencies in the information gathered from different sources. For instance, we assumed that distributors self-report their presence in a distribution area correctly (because DNSPs should know well their area of operation). Hence, we gave primacy to all occasions where a DNSP self-reported that it serves a particular postcode.

Data extracted from DNSPs' responses to the AER's benchmarking Regulatory Information Notices (RINs) were also utilised to match distributors to postcodes. Within the RIN templates, a distributor must report the weather stations within its service areas, and the postcodes that correspond to those weather stations. We treated this as self-reporting, and therefore assumed that any postcode reported within a DNSP's RIN response must fall within its service area. While not all postal areas have weather stations, the data obtained from the

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33 ActewAGL does provide an online lookup tool, however it does not distinguish between retailers and distributors – making it of little use in the current analysis.

34 ABS Postcodes & Postal Areas Fact Sheet: Postcodes and Postal Areas (POAs)

RINs allowed additional distributor-postcode matches to be identified (which were missed by the online lookup tools).

Data accuracy

A relatively high degree of confidence can be placed in the distributor-postcode matches for Victoria. Of the five DNSPs in Victoria (AusNet, Powercor, Citipower, Jemena, and United Energy), self-reported data could be found for all distributors except AusNet. While AusNet does provide a distributor search tool online, the tool is primarily designed to give users information about current outages occurring in their network. The structure of the webpage and the type of output information meant that an automated search could not be conducted for AusNet's lookup tool within the timeframe available. This lack of self-reported data was not deemed to be of critical importance for two reasons:

- The Victorian Electricity Supply Industry (VESI) suggests that consumers use Jemena's distributor search tool.[35] AusNet is part of VESI, so we assumed that Jemena's lookup tool would report AusNet's distribution locations with reasonable accuracy; and
- Data obtained from United Energy and Jemena both report AusNet as servicing exactly the same postcodes. Consistency from multiple sources is a good indication that the data are accurate.

Whilst it was possible to use multiple sources to identify DNSPs' postcodes in Victoria, similar access to data was unavailable for other States. This increased the reliance on Energy Australia's data in other regions. Energy Australia reported distributors servicing locations well outside a DNSP's expected area of operation. One such example is for the postcode 4101, located in Queensland. Energy Australia reported CitiPower and Energex as servicing the area, which is clearly wrong, as CitiPower only operates in Victoria. Such results revealed the limitations of Energy Australia's database, and highlighted the need to check results in order to ensure a distributor's area of operation was reasonable.

Conflicting information from multiple sources made it difficult to accurately assign distributors to postcodes on some occasions. An example of a questionable assignment is for the postcode 4350, located close to Toowoomba. Energy Australia reported Energex and Ergon as both servicing this location. However Energex's self-reported data do not acknowledge servicing the area. In addition, Ergon stated that it has a 'Key Administration Centre' in Toowoomba – greatly increasing the likelihood that Ergon is the sole distributor in the area. To further complicate matters, Energex reported as servicing a postcode 4352, which

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35 Victorian Electricity Supply Industry (VESI), http://www.vesi.com.au/.

upon initial inspection looked to fall clearly within Ergon's distribution area.[36] Further investigation revealed that 4352 did not have one contiguous border, but was split into multiples areas to the east and south of Toowoomba. Therefore it is possible that both Energex and Ergon serviced this postcode. However, the extent to which one distributor serviced the area over the other could not be determined. This 'doubling-up' of distributors in postcodes was particularly prevalent in NSW, however further investigation of such locations often allowed one of the distributors to be eliminated from the postcode. Plausible locations where two or more distributors could service the same postcode were also identified. These locations often occurred on distribution area and state boundaries. For such locations multiple distributors were allowed to be matched to the same postcode.

Other anomalies

A number of postcodes in the search list were associated with institutions – resulting in 'no match' errors. Further, some postcodes were found to no longer exist.[37] The use of distribution area maps provided by DNSPs, as well as Google Maps assisted in allocating these postcodes to distributors where possible. It should be noted that there are instances in the census data of postcodes reporting positive populations but zero dwellings.[38] Similarly, a number of postcodes (mainly PO boxes) had zero area. A postcode with zero area was deemed to be of little use in the current analysis as it would not be possible to calculate a population or dwelling density. As a consequence such postcodes were removed from the search list.

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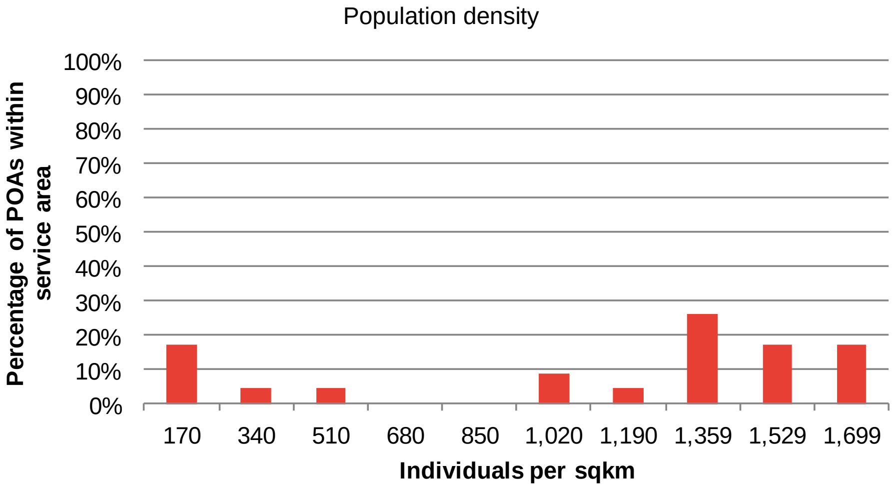
36 Ergon distribution area map: https://www.ergon.com.au/network/contractors-and-industry/service-regions-and-depot-map.

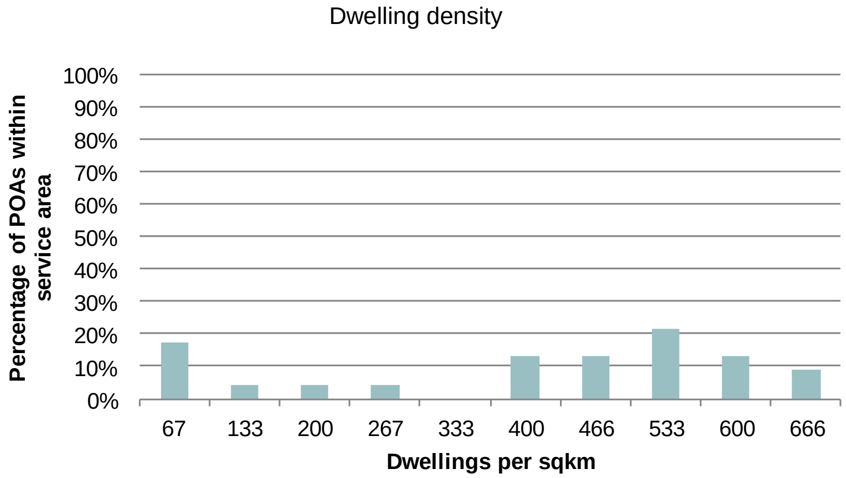
37 According to Australia Post's online lookup tool, http://auspost.com.au/postcode.

38 One such example is La Trobe University. The Census data show that 1,003 people resided at the University on the night of the Census, however the University is reported as having zero dwellings.

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

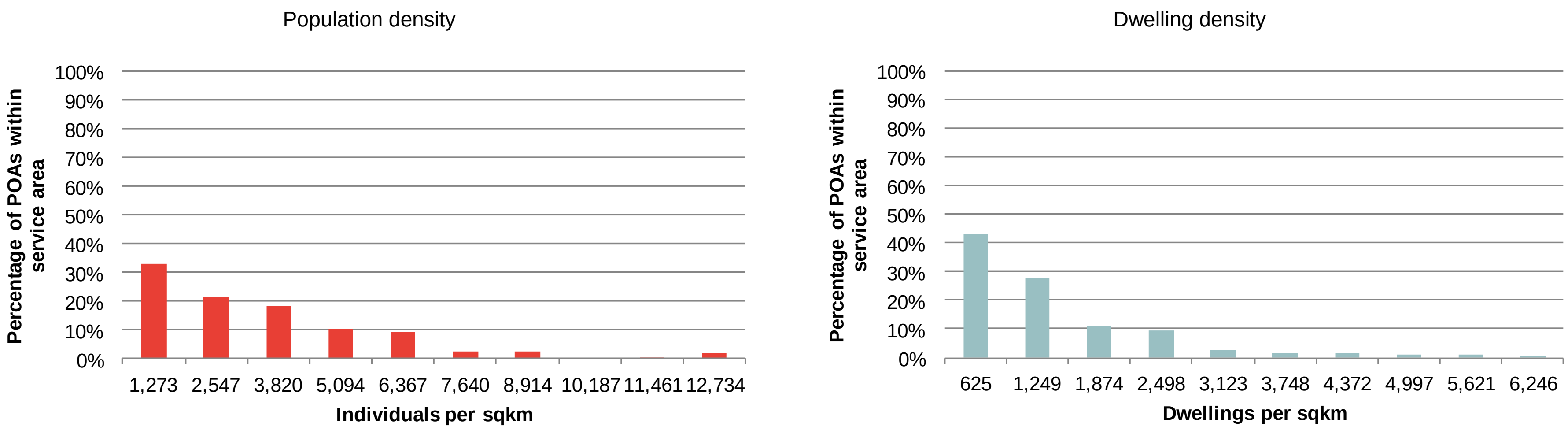
Figure 36: Density distributions – ActewAGL





Source: Frontier analysis of ABS Census data

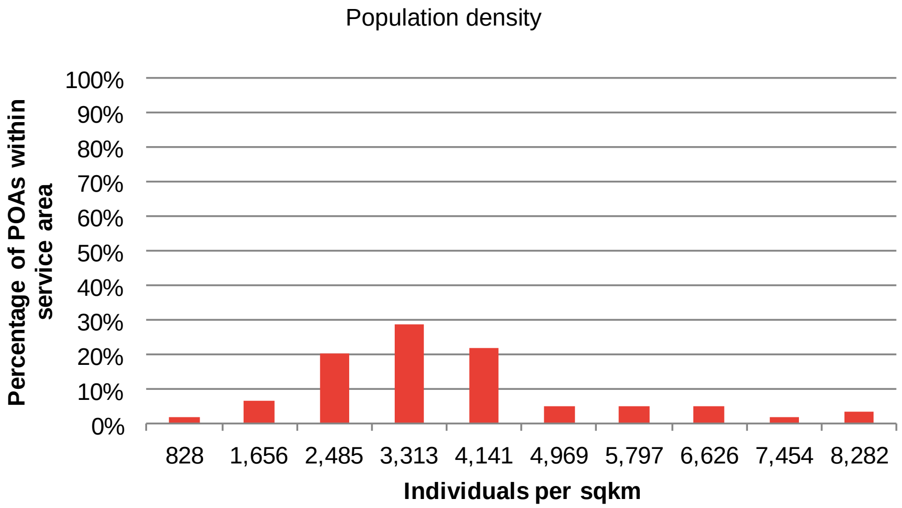
Figure 37: Density distributions – Ausgrid

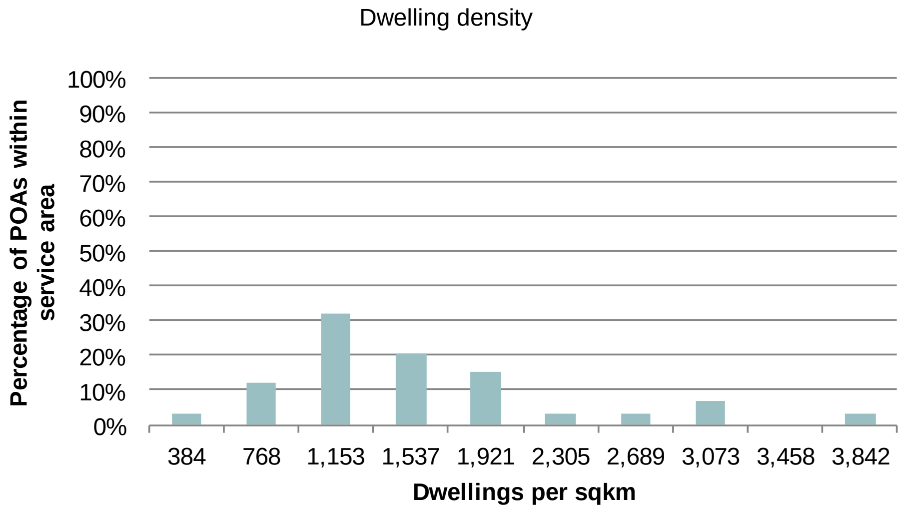


Source: Frontier analysis of ABS Census data

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

Figure 38: Density distributions – CitiPower

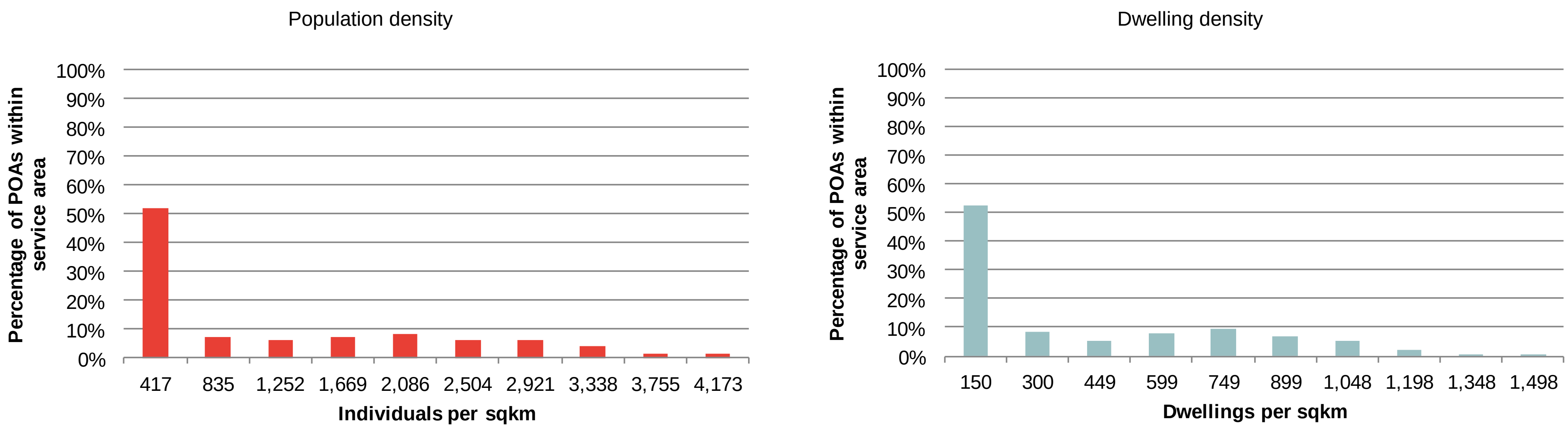




Source: Frontier analysis of ABS Census data

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

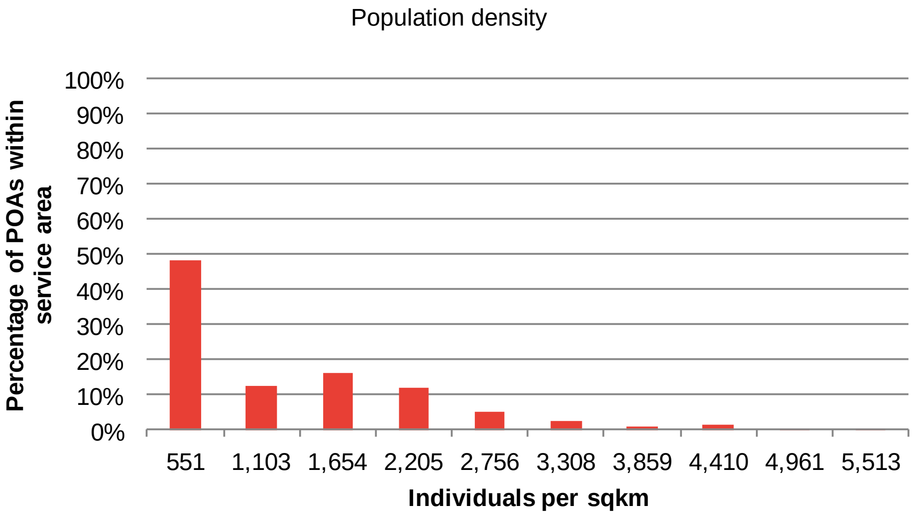
Figure 39: Density distributions – Endeavour Energy

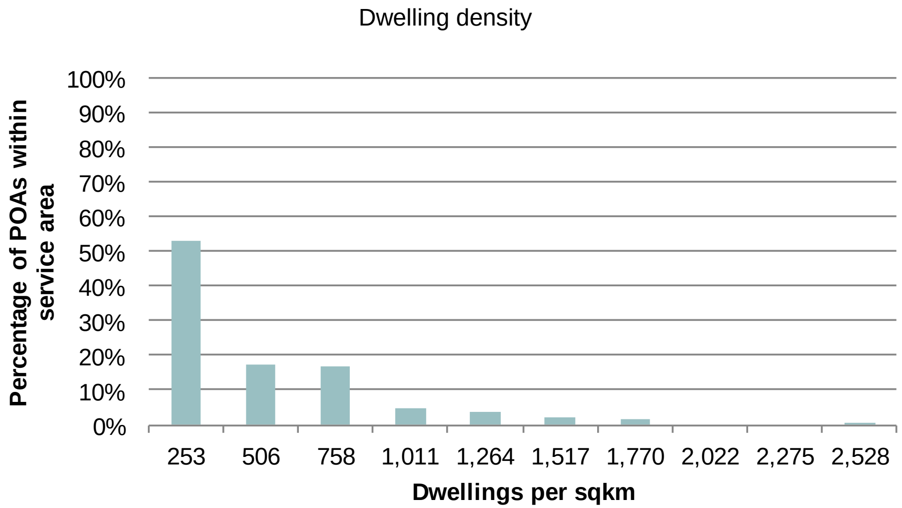


Source: Frontier analysis of ABS Census data

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

Figure 40: Density distributions – Energex

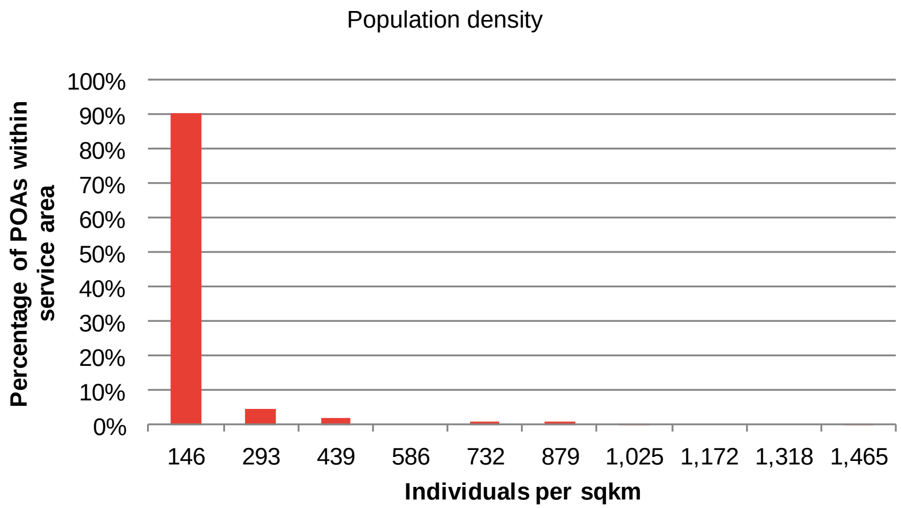


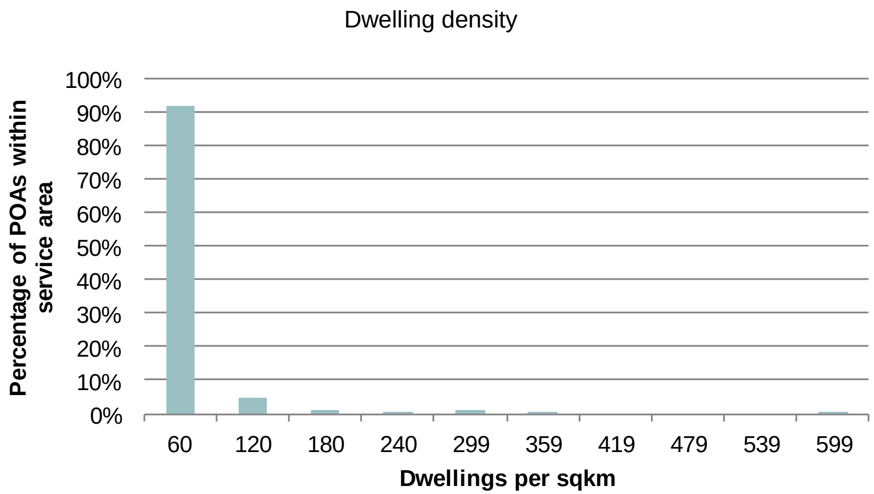


Source: Frontier analysis of ABS Census data

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

Figure 41: Density distributions – Ergon Energy

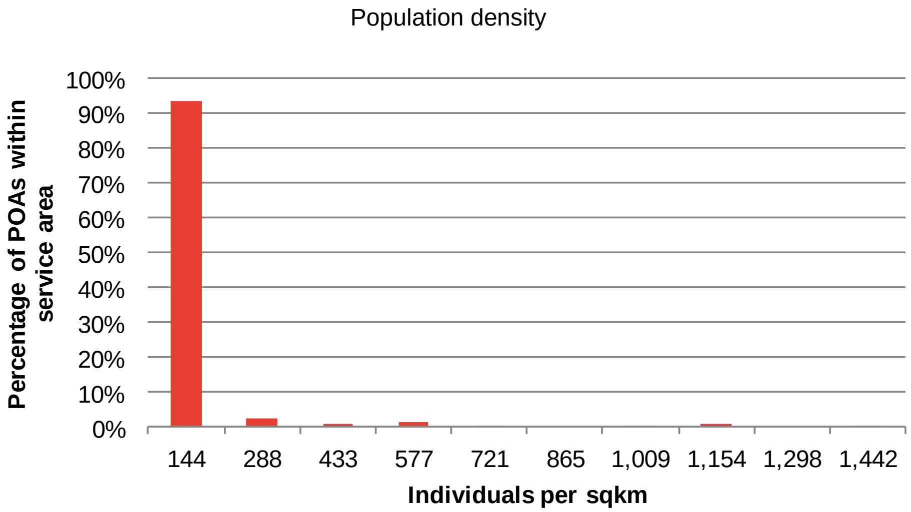


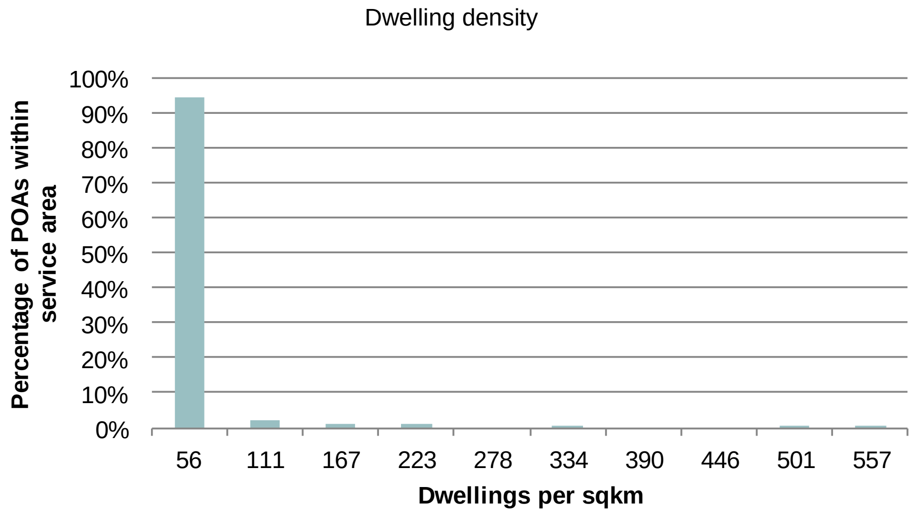


Source: Frontier analysis of ABS Census data

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

Figure 42: Density distributions – Essential Energy

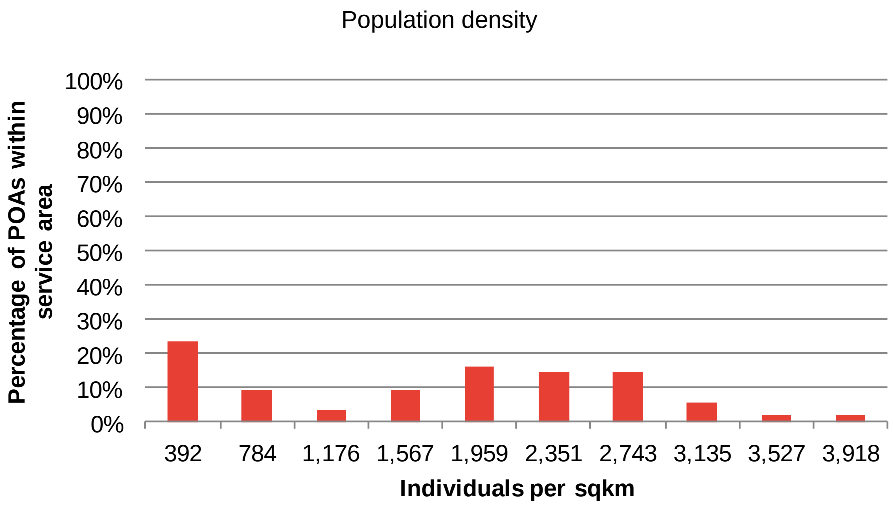


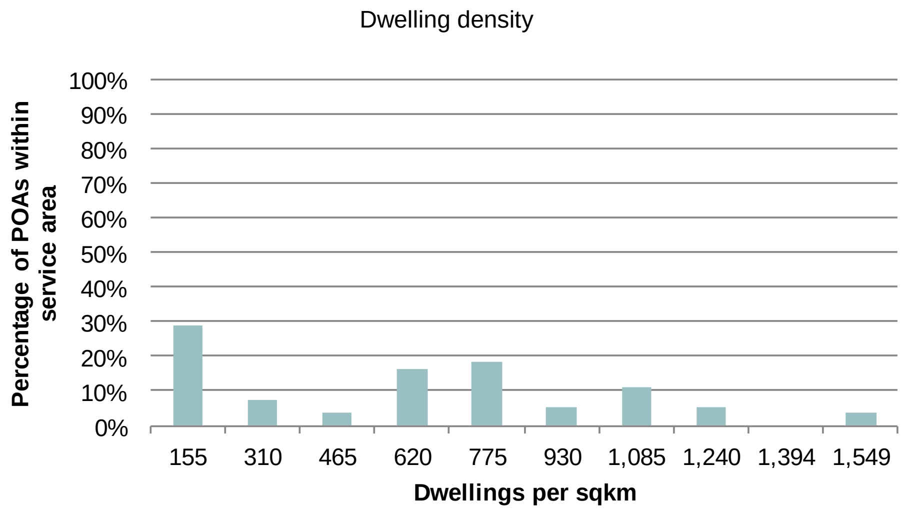


Source: Frontier analysis of ABS Census data

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

Figure 43: Density distributions – Jemena

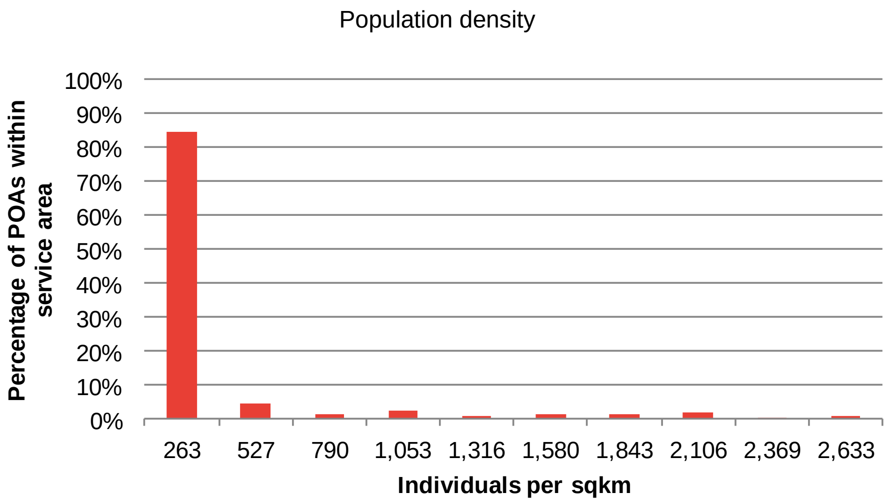


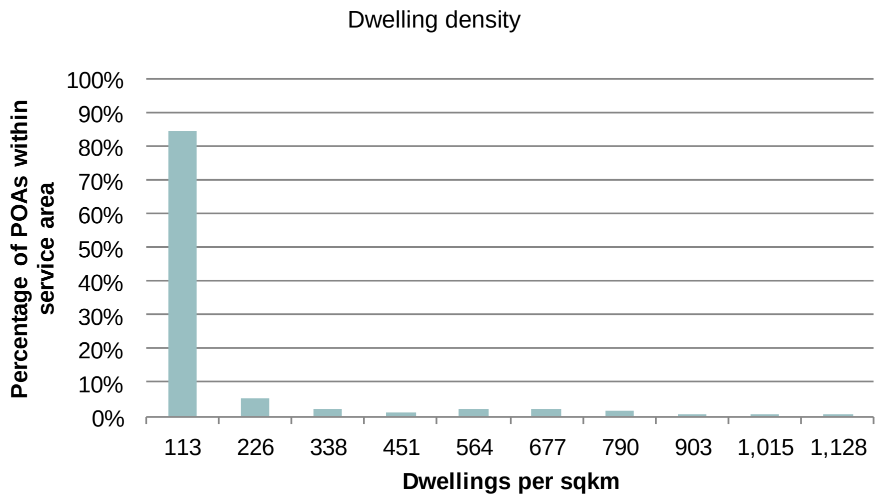


Source: Frontier analysis of ABS Census data

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

Figure 44: Density distributions – Powercor

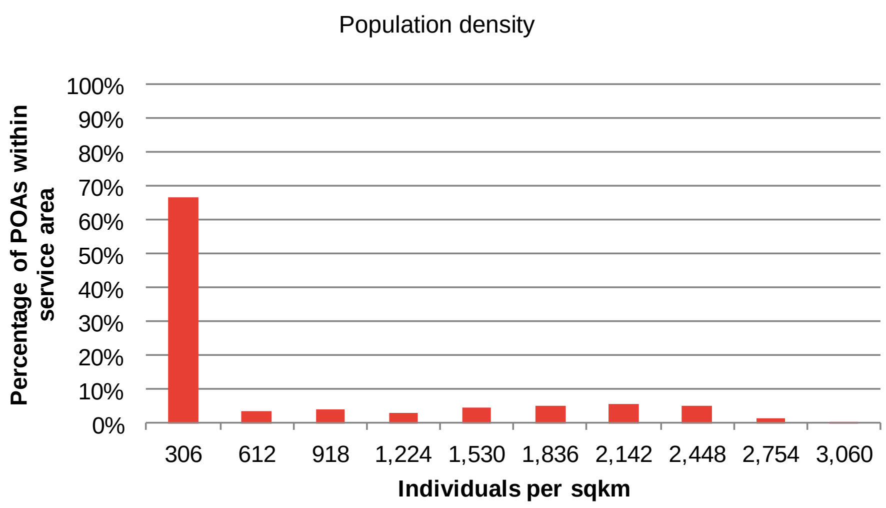


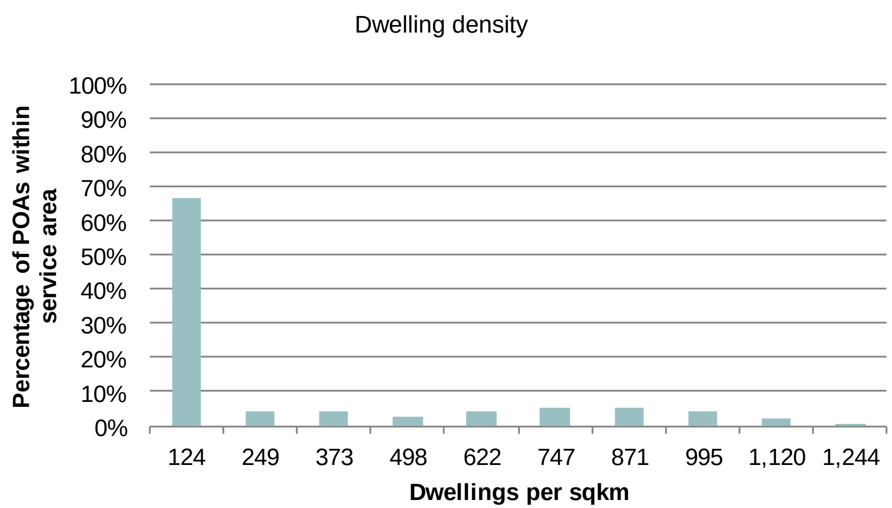


Source: Frontier analysis of ABS Census data

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

Figure 45: Density distributions – SA Power Networks

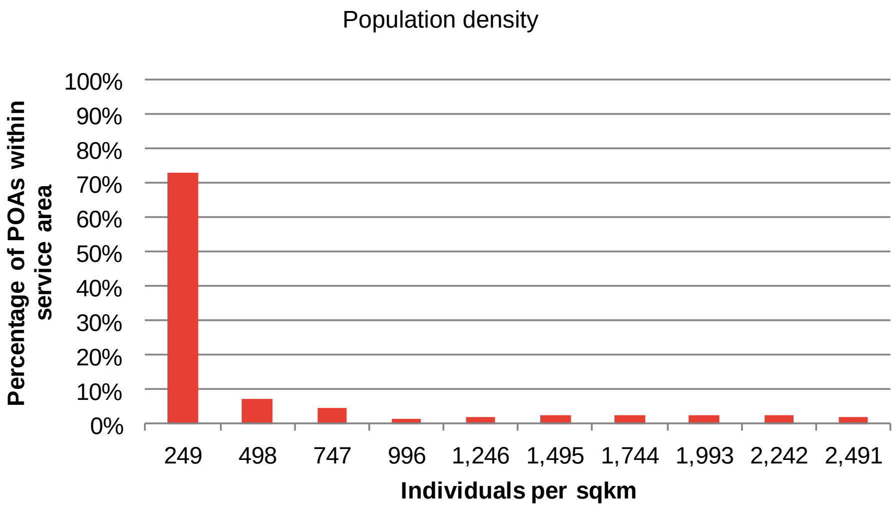


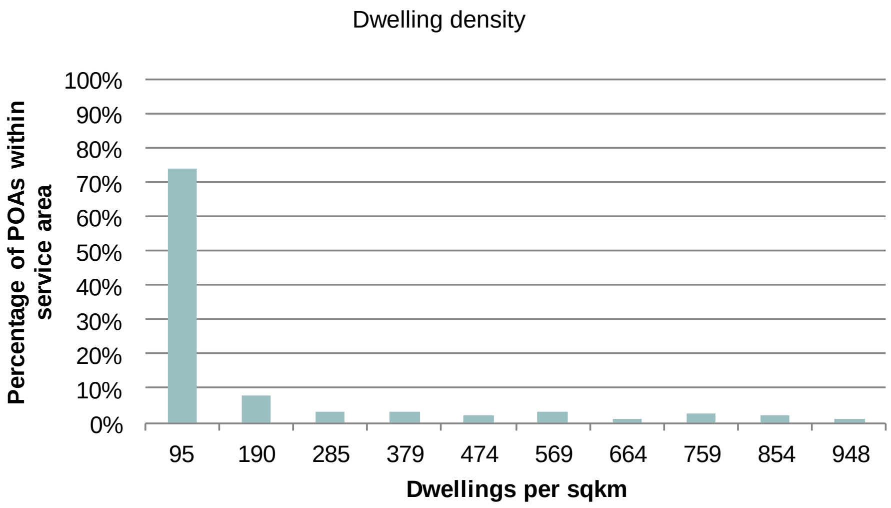


Source: Frontier analysis of ABS Census data

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

Figure 46: Density distributions – SP AusNet

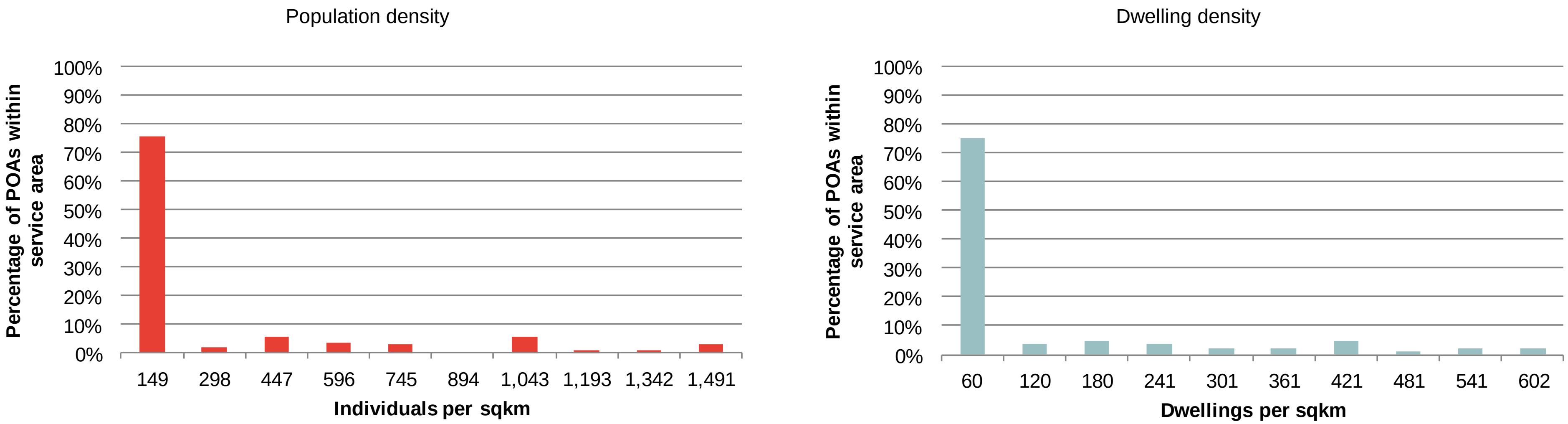




Source: Frontier analysis of ABS Census data

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

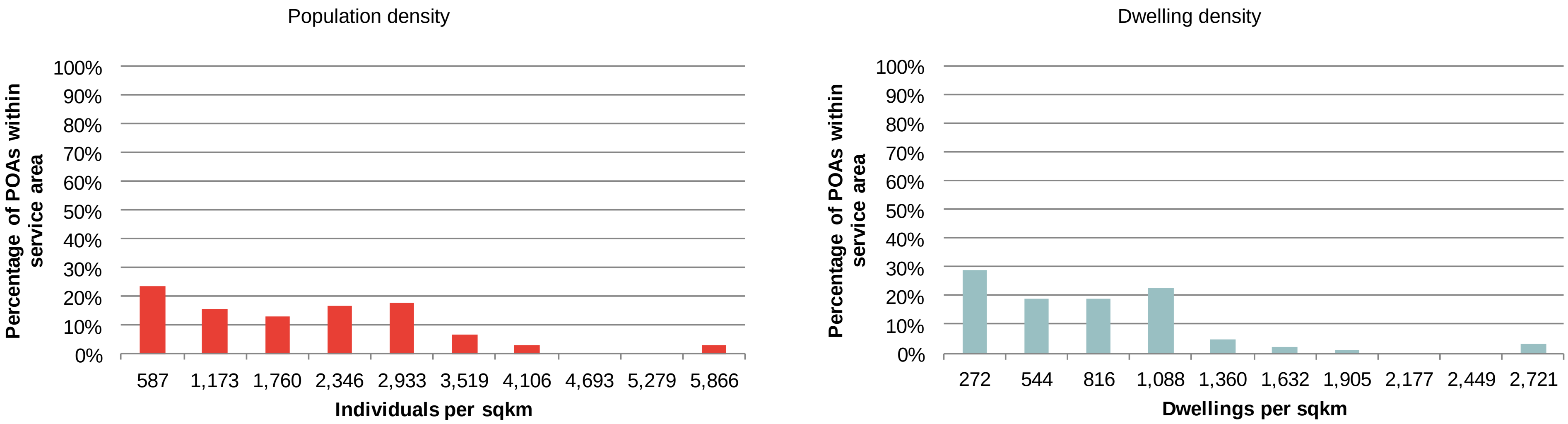
Figure 47: Density distributions – TasNetworks



Source: Frontier analysis of ABS Census data

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

Figure 48: Density distributions – United Energy



Source: Frontier analysis of ABS Census data

Appendix B – Density distributions using Postal Area and Census data within DNSP service areas

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