Σ ECONOMIC
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Memorandum

From: Denis Lawrence, Tim Coelli and John Kain **Date:** 4 November 2016

To: Su Wu, Andrew Ley and Joanne Ingham

CC: AER Opex Team

Subject: DNSP Economic Benchmarking Results for AER Benchmarking Report

Economic Insights has been asked to update the electricity distribution network service provider (DNSP) multilateral total factor productivity (MTFP) and multilateral partial factor productivity (MPFP) results presented in the Australian Energy Regulator's 2015 DNSP Benchmarking Report (AER 2015b). The update involves including data for the 2014–15 financial and 2015 calendar years (as relevant) reported by the DNSPs in their latest Economic Benchmarking Regulatory Information Notice (EBRIN) returns. It also includes a small number of revisions to DNSP data, mainly relating to further refinement of MVA factors for lines and cables.

We have also been asked to update the three sets of opex cost function econometric results presented in Economic Insights (2014, 2015a,b) to include 2014–15 or 2015 data for the Australian DNSPs, as relevant, and to update the New Zealand and Ontario data by another year.

MTFP specification used

The DNSP MTFP measure has five outputs included:

- Energy throughput (with 12.8 per cent share of gross revenue)
- Ratcheted maximum demand (with 17.6 per cent share of gross revenue)
- Customer numbers (with 45.8 per cent share of gross revenue)
- Circuit length (with 23.8 per cent share of gross revenue), and
- (minus) Minutes off–supply (with the weight based on current AEMO VCRs).

The DNSP MTFP measure includes six inputs:

- Opex (network services opex deflated by a composite labour, materials and services price index)
- Overhead subtransmission lines (quantity proxied by overhead subtransmission MVAkms)
- Overhead distribution lines (quantity proxied by overhead distribution MVAkms)
- Underground subtransmission cables (quantity proxied by underground subtransmission MVAkms)

- Underground distribution cables (quantity proxied by underground distribution MVAkms), and
- Transformers and other capital (quantity proxied by distribution transformer MVA plus the sum of single stage and the second stage of two stage zone substation level transformer MVA).

In all cases, the annual user cost (AUC) of capital is taken to be the return on capital, the return of capital and the tax component, all calculated in a broadly similar way to that used in forming the building blocks revenue requirement.

Data revisions

Data revisions have mainly focused on further refinements to estimated MVA factors for lines and cables. In some cases where DNSPs have provided revised MVA factors for 2015, these have also been applied to earlier years (eg AusNet Distribution). Some refinements have also been made to methods used to calculate line and cable lengths. Some changes have been made to RAB values in line with changes in guidelines and price determinations. These refinements and changes have generally had quite minor impacts on the economic benchmarking results. We have also decided to include the CAM change for ActewAGL.

Issues raised in DNSP submissions on Draft Benchmarking Report

ActewAGL submitted that no changes have been made to the data sources and modelling approach used in the AER's Draft 2016 Benchmarking Report compared to the two preceding years. ActewAGL further claimed that 'there are clearly superior models available, some of which were presented to the AER during the last regulatory determination'. Economic Insights (2015a) undertook a detailed review of the alternative models submitted during the ACT and NSW DNSPs' regulatory determinations and found that all of the models submitted contained significant flaws. ActewAGL also noted that parts of the Australian Competition Tribunal's decision on the ACT and NSW DNSPs' appeals against their final determinations were critical of the AER's reliance on economic benchmarking. The AER is currently appealing the decision of the Tribunal to the Federal Court. The AER intends to undertake consultation on ways in which its EBRIN data collection and economic benchmarking modelling can be further refined.

ActewAGL requested the AER to change to using data based on its revised Cost Allocation Methodology (CAM) which took effect from June 2013 and for which ActewAGL supplied backcast data for the years 2006–13 in March 2016. We note that ActewAGL's revised CAM took effect prior to the AER's November 2014 Draft Determination and the AER's initial Benchmarking Report (AER 2014b,a). It also potentially removes ActewAGL's capitalisation policy outlier status and the associated need for an operating environment factor (OEF) adjustment as discussed in AER (2015a). Economic Insights (2015b, p.3) recommended the AER require DNSPs to supply future EBRIN data on the basis of their CAMs in place in 2013 to minimise scope for potential gaming. Since ActewAGL's revised CAM meets this criterion, removes an anomaly and backcast data are now available, the revised CAM is used in the benchmarking results reported in this memo. The AER's approach to post–2013 CAM changes will be finalised after consultation on refinements to EBRIN data collection.

ActewAGL also made a number of observations regarding the MTFP methodology. It claimed that 'MTFP does not account for differences in network design or operating differences'. However, the MTFP and MPFP models do include allowance for the main network density differences (via the output specification – as do the econometric operating cost function models) and they also include allowance for the network design of some DNSPs having two step rather than single step transformation at the zone substation level. Network density differences are generally recognised as the most important OEFs to allow for in economic benchmarking studies. The MTFP and MPFP models also directly incorporate differences in network reliability. Additional OEFs could be allowed for by ex–post adjustment or, alternatively, by second stage regression analysis.

ActewAGL also claimed that it would require ‘completely unrealistic expectations of opex’ for the least efficient performers to equal the performance of the four most efficient performers. However, being a holistic model, it needs to be recognised that large changes in performance will take time to achieve as they are dependent on changes in capital quantities as well as changes in opex. Hypothetical calculations of the type quoted by ActewAGL are thus not meaningful.

Finally, ActewAGL claimed that the MTFP results were so sensitive to changes in specification as to limit their usefulness. It quoted changes in the way cable lengths are measured and how high voltage assets are treated in the model in support of this statement. However, examination of these issues shows ActewAGL’s claim is unfounded. The former claim appears to be based on earlier advice to ActewAGL from Huegin which purports to show that rankings change if lines and cables input are measured in kilometres instead of MVA–kilometres. However, measuring capital input quantity in this simplistic way is untenable as it implies that a kilometre of subtransmission line is exactly equivalent to a kilometre of suburban distribution line. It was further claimed that excluding ActewAGL’s 132 kV lines and associated opex would further improve ActewAGL’s ranking. However, for such an exercise to be meaningful, subtransmission lines and opex would have to be excluded for all DNSPs – not just selectively for one. And, in response to earlier submissions that the bulk of the MVA–kilometre measure was contributed by subtransmission lines, Economic Insights moved to separating lines and cables into subtransmission lines and distribution lines categories in recognition of the generally small share of subtransmission in total cost compared to distribution lines and cables. This change had little impact on the results.

Ausgrid submitted constructive comments across three broad areas: recognising the value of outputs created by costs incurred and not just the costs themselves; comparing like with like; and, recognising step changes in productivity more quickly.

Ausgrid argued that while the cost of high levels of replacement capex (repex) are recognised in the MTFP modelling, resulting benefits will not necessarily be reflected in increases in the outputs included. It should be noted that repex has only quite a minor impact on the input side of the MTFP analysis by changing the weight given to capital inputs as asset values increase as a result of increased levels of repex. Because we use a physical quantity proxy approach to measuring input quantities, the effect will be minimal compared to the so-called 'monetary' approach to measuring capital input quantity where an increase in repex would translate directly to an increase in capital input quantity and an associated decrease in productivity.

Ausgrid questioned whether the possible link between asset age and productivity was taken into account in the economic benchmarking analysis. It drew the analogy of comparing the performance of a 15 year old car and a new car, with the older car requiring higher levels of maintenance. AER (2015a) undertook some analysis of differences in asset age between networks and found no evidence of identifiable differences. We also note that the relatively ‘one hoss shay’ physical depreciation characteristics of network assets mean that the increase in required maintenance as the asset ages is considerably less than is the case for plant and machinery assets such as cars. AER (2015a) assessed whether an OEF adjustment needed to be made for the impact of differences in network asset age on opex and found no evidence of a material relationship.

Ausgrid also argued that the impact of large abnormal costs should be excluded from the economic benchmarking analysis. In particular, it noted that Ausgrid had to deal with the aftermath of a large storm during the 2015 reporting year and incurred large voluntary redundancy costs as it substantially downsized its workforce during 2015. The EBRINs do not currently collect data on voluntary redundancy payments and storm costs. Since all DNSPs incur these costs at varying times and they are included in opex, we are not currently able to undertake economic benchmarking net of these abnormal costs. If they were excluded for one DNSP, they would have to be excluded for all DNSPs in all years.

The AER sought further information from Ausgrid on the size of its storm–related and voluntary redundancy payments. Ausgrid listed its abnormal storm–related costs during 2015 as being $34 million. Ausgrid indicated its voluntary redundancy costs allocated to Standard Control Services were: $12.7 million in 2012–13; $24.6 million in 2013–14; $107.2 million in 2014–15; and, $91.9 million in 2015–16.[1] If both abnormal costs were removed for Ausgrid only and for 2015 only, Ausgrid's opex partial factor productivity would be around 28 per cent higher in 2015, all else equal. Excluding just voluntary redundancy costs would lead to Ausgrid's opex partial factor productivity being around 20 per cent higher in 2015, all else equal. The AER may want to ask all NSPs to itemise redundancy costs and other abnormal items in their EBRINs in future.

On the issue of comparing like with like, Ausgrid questioned whether sufficient attention has been paid to ensuring DNSP cost allocation methods are comparable. Capitalisation policy differences have been examined in AER (2015a) and other recent determinations. ActewAGL was found to be the main outlier in these studies in terms of opex to totex ratios. As noted above, our adoption of ActewAGL's June 2013 CAM change addresses this issue.

Ausgrid also presented a graph purporting to show a negative relationship between the opex to totex ratio and MTFP scores across DNSPs in 2015. However, the data underlying this graph mistakenly includes feed–in tariff payments for some DNSPs and it would be inappropriate to place weight on single year results given the relative volatility of capex compared to opex. We furthermore note that MTFP results are driven by differences in capital stock quantities and asset values, not differences in capex.

While we are not convinced that capitalisation policy differences across DNSPs are currently a major issue and we have addressed the issue for the one DNSP where this did appear to be relevant in the accompanying modelling, we agree with Ausgrid that further analysis of this topic would be beneficial. In particular, the issue of whether future CAM changes will be allowed or whether economic benchmarking will continue to use the CAMs in place in 2013 will be considered by the AER. Our concern is that allowing future CAM changes for benchmarking potentially opens up significant gaming opportunities for DNSPs.

Ausgrid also raised concerns that it might be disadvantaged by its legacy system structure involving high voltage subtransmission assets and the proportion of total MVA–kilometres attributed to these lines. As noted above, we have moved to separating lines and cables into

[1] Email from Ausgrid to the AER dated 28 October 2016.

subtransmission lines and distribution lines categories in recognition of the generally small share of subtransmission in total cost compared to distribution lines and cables. This change had minimal impact on the results, except for TasNetworks Distribution which has complained that it is disadvantaged by having very little high voltage subtransmission lines and cables. And, as acknowledged by Ausgrid, we have excluded the first stage of two stage transformation at the zone substation level for those DNSPs, including Ausgrid, that have more complicated system structures. Further changes would require excluding subtransmission lines for all DNSPs – something that would be inappropriate since subtransmission is an integral part of DNSP operations. We also note that an OEF adjustment for differing levels of subtransmission intensity has been included in analyses used in Determinations (see, for example, AER 2015a).

Ausgrid noted that it has a mixture of customer densities in its service area and suggested that DNSPs be required to report costs by region such as CBD, urban, semi–rural and remote. We note that most Australian DNSPs cover a range of customer densities in their service areas and so Ausgrid is by no means unique in this regard. We also have some concerns that a requirement for more disaggregated cost reporting by geographic area would place a significant reporting burden on DNSPs and would involve a range of cost allocation challenges.

Finally, with regard to recognising step changes in improvements, Ausgrid argued there should be more emphasis placed on more recent performance results so that efforts to significantly reduce costs are recognised more quickly. The AER's partial indicator analysis presents average results for the last five years and the MTFP and MPFP analyses present yearly results. The econometric operating cost function models present average results for the whole period from 2006 onwards. This is a requirement of the econometric models estimated. The combination of period average results, average results for the last five years and yearly results for the different analyses presented provide a full picture of DNSP performance. A more relevant question is whether 'abnormal' costs such as voluntary redundancy payments and major storm event recovery should be excluded. As discussed above, the AER intends to consult on this issue and possibly seek this information from all DNSPs.

Ausgrid also suggested that consideration be given to including DNSPs' forecast costs as well as historic costs in the benchmarking analyses. We note that the British regulator Ofgem currently does this. However, all British DNSPs are reviewed at the one time whereas reviews of the Australian DNSPs occur at different times. This would make inclusion of forecast costs problematic in Australia. Furthermore, such an approach would be at odds with the base/step/trend method used in Australia to assess DNSP forecasts.

The submission from **AusNet Services Distribution** (AND) advocated inclusion of community safety as a distribution output in the MTFP model. AND argued that if this is not done, the model penalises networks that have significant expenditure due to legislative obligations aimed at minimising the risk of bushfire ignition. It quoted the example of its obligation to roll–out Rapid Earth Fault Current Limiters (REFCLs) which will increase its capex by $200 million over 2016–21. We recognise the importance of public safety as an output for DNSPs. But we also recognise the challenges in developing a consistent and meaningful way of forming and measuring a safety output for all included DNSPs. This would be a useful topic for consultation with DNSPs in the AER's forthcoming review of the economic benchmarking data and methodology.

AND noted that it had included debt raising costs in its EBRIN opex for 2015 but not for earlier years. AND's debt raising costs have now been excluded for 2015. These costs are generally very small compared to total opex. The appropriate treatment of debt raising costs – which are a cost associated with capex but included with opex for some regulatory purposes – will be the subject of future consultation with DNSPs.

AND also commented that its customer density figure for 2015 in the AER's economic benchmarking database did not appear to be consistent with its 2015 data. However, the figure is a five–year average rather than an annual one.

Endeavour Energy made a number of complaints in its submission, some of which were similar to those made by ActewAGL. Endeavour claimed it had had insufficient time to interrogate the economic benchmarking data and check for errors. We note that the process of data collection and verification has now been underway for over three years and the 2015 data has been in the public domain for several months. The AER has undertaken extensive checking of the data and the DNSPs have had three weeks to review the draft benchmarking results with extensions being granted where requested.

Endeavour submitted that little change or evolution had occurred to the data sources and modelling approach used in the AER's Draft 2016 Benchmarking Report compared to the two preceding years. Endeavour further claimed that 'demonstrably superior' econometric models have been presented to the AER during regulatory determinations. As noted above, Economic Insights (2015a) undertook a detailed review of the alternative models submitted during the ACT and NSW DNSPs' regulatory determinations and found that all of the models submitted contained significant flaws. We again note that the AER intends to undertake consultation on ways in which its EBRIN data collection and economic benchmarking modelling can be further refined once all relevant appeals and associated legal proceedings are concluded.

Endeavour complained that inadequate emphasis is given to benchmarking results for the latest year and that too much emphasis is given to an 'ever–expanding averaging period'. As noted above, the AER's partial indicator analysis presents average results for the last five years and the MTFP and MPFP analyses present yearly results. The econometric operating cost function models present average results for the whole period from 2006 onwards. This is a requirement of the econometric models estimated. The combination of period average results, average results for the last five years and yearly results for the different analyses presented provide a full picture of DNSP performance.

Endeavour comments that the Ontario data used in our econometric modelling 'has not been added to since 2012'. This is incorrect. The New Zealand and Ontario data have both been updated by the same number of years as the Australian data in the last two Benchmarking Reports, thus maintaining a balanced panel for estimation.

Endeavour claims that the outputs and inputs and their respective weightings used in the MTFP model were 'arbitrarily selected'. This is incorrect. The development of the MTFP specification is the culmination of over two decades' development by a range of analysts in Australasia and North America. The Ontario Energy Board uses a similar output specification developed originally by Pacific Economics Group and the Commerce Commission in New Zealand uses models with similar output and input specifications. The output and input specifications were the subject of extensive consultation with stakeholders during workshops held in 2013. Background and details on the development of the specifications and their rationale can be found in Economic Insights (2013a,b,c,d,e and 2014a). While most DNSPs sent representatives to most of the workshops, a few DNSPs chose not to constructively engage with the process.

Endeavour also complains that it will be disadvantaged by having high voltage subtransmission lines and cables. As discussed above, we have moved to separating lines and cables into subtransmission lines and distribution lines categories in recognition of the generally small share of subtransmission in total cost compared to distribution lines and cables. This change had minimal impact on the results, except for TasNetworks Distribution which has complained that it is disadvantaged by having very little high voltage subtransmission lines and cables.

Endeavour argues that more extensive allowance should be made in the Benchmarking Report for the incorporation of OEFs in the results presented. As already noted, the MTFP, MPFP and operating cost function results presented incorporate allowance for the key OEFs of customer, energy and demand network densities. The AER's partial performance indicator analyses also allow for the key network density differences. As analysis for additional OEFs is refined and completed, consideration will be given to presenting results adjusted for the effects of a wider range of OEFs.

Endeavour claimed it was inappropriate for the AER to comment on relative DNSP efficiency in its Benchmarking Reports at this point in time. However, the purpose of the Benchmarking Reports was made clear by the AEMC (2012, p.vii) which stated that:

> 'The AER will be required to publish annual benchmarking reports, setting out the *relative efficiencies* of NSPs *based on the information available to it*.' (emphasis added)

Finally, Endeavour complained of an initial 'counter–intuitive' decline in its MTFP between 2014 and 2015. Further investigation by Endeavour revealed this was due to an error in data supplied. The AER had in fact drawn Endeavour's attention to this issue prior to circulating the draft benchmarking report. Endeavour's EBRIN error has been corrected in the accompanying analysis.

The **Ergon Energy** submission raises a number of the same issues raised by ActewAGL and Endeavour. These include limited change in the economic benchmarking data and methodology used compared to the previous two Benchmarking Reports, the change in opex required to reach the upper levels of MTFP performance, the relationship between opex to totex ratios and MTFP scores, CAM changes, the impact of having high voltage subtransmission lines and cables on MVA–kilometre measures, the extent to which OEFs are allowed for and the time period concentrated on. These issues have been addressed above and the commentary will not be repeated here.

In response to questioning over its large reported network services opex increase for 2015, Ergon attributed its opex rise in 2015 to a number of reasons, including lower than normal preventative maintenance costs in 2014, higher opex due to weather and storm events in 2015, and writing–off non–proceeding capital works in 2015. As noted above, the treatment of 'abnormal' opex will be the subject of consultation going forward. Annual fluctuations in opex due to such factors lend support to basing efficiency comparisons on average results rather than annual results.

Ergon also notes the potentially problematic issue of how to incorporate reliability as an output in the MTFP analysis. It notes that storm events that fall just short of being classified as major event days (MEDs) can still impose significant costs on the network while also currently incurring an output penalty while no output penalty would be incurred for a storm event that might be only slightly worse (but just over the MED threshold). Furthermore, Ergon notes that increases in customer numbers can currently result in a reliability output penalty if SAIDI remains constant (because the negative reliability output is the product of SAIDI and customer numbers). We acknowledge that the incorporation of reliability as an output in productivity studies presents considerable challenges, as discussed in Economic Insights (2013a,c,e) and that no measure is likely to be perfect. The current negative reliability output measure is judged to be the most tractable method currently available. Further refinements will be considered as part of the review of economic benchmarking to take place once relevant appeal and associated legal proceedings are completed.

The **Essential Energy** submission also raises a number of the same issues raised by ActewAGL, Endeavour and Ergon. These include limited change in the economic benchmarking data and methodology used compared to the previous two Benchmarking Reports, the change in opex required to reach the upper levels of MTFP performance, CAM changes, the extent to which OEFs are allowed for and the time period concentrated on. These issues have been addressed above and the commentary will not be repeated here.

Essential noted that rural DNSPs sometimes have to install assets with greater capacity than would otherwise be the case to allow for voltage drop over large distances and because the minimum size asset available may be larger than that required to service the small number of customers on some rural lines.

Essential claimed that the use of circuit length as an output would advantage urban DNSPs by making them ‘appear larger’ than they really are. We disagree with this. It needs to be recognised that multi–circuit lines can deliver more electricity then single circuit lines. Not recognising this would be analogous to saying a kilometre of a country lane was equivalent to a kilometre of a multi–lane freeway.

Essential noted that DNSP costs had increased as a result of increasing solar photo–voltaic penetration and changes in state licensing conditions. AER (2015a) examined the issue of increasing solar penetration and found broadly similar rates of solar penetration across NSW and Victorian DNSPs. These penetration rates were just under half those found in Queensland and South Australia. Essential also noted that customer numbers may be less important to sparse rural DNSPs than network length.

In its submission **TasNetworks Distribution** (TND) supported the AER’s cautious approach towards using benchmarking results deterministically.

As noted above, TND indicated that it appeared to be disadvantaged in MTFP measurement by not having high voltage subtransmission assets. As discussed in more detail in Economic Insights (2015b), this effect arises from the relatively higher weight given to TND’s distribution lines compared to other DNSPs under the current input specification. Because TND serves a dispersed customer base with relatively small numbers of customers in a range of rural areas, it will likely have to build lines that have excess capacity to reach a small number of outlying customers. TND requested that the qualification regarding its outlier status in terms of system structure contained in AER (2015b) be repeated in this year’s Benchmarking Report. Economic Insights supports this request.

TND also noted that, given its dispersed customer base, it will have some degree of excess capacity in its use of transformer assets which, in some cases, might only serve one remote customer. This may place it at a disadvantage in MTFP comparisons.

Updated MTFP and MPFP results

DNSP MTFP, opex MPFP and capital MPFP results are presented in figures 1 to 3.

Figure 1 **DNSP multilateral total factor productivity indexes, 2006–2015**

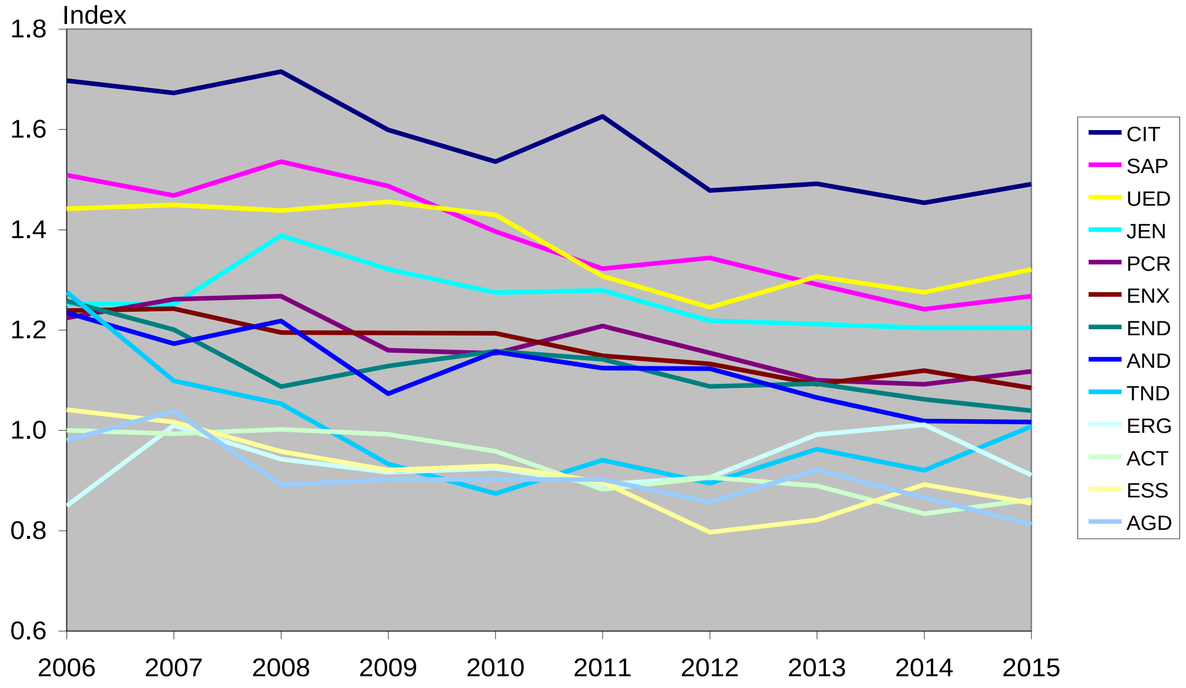


Figure 2 **DNSP multilateral opex partial factor productivity indexes, 2006–2015**

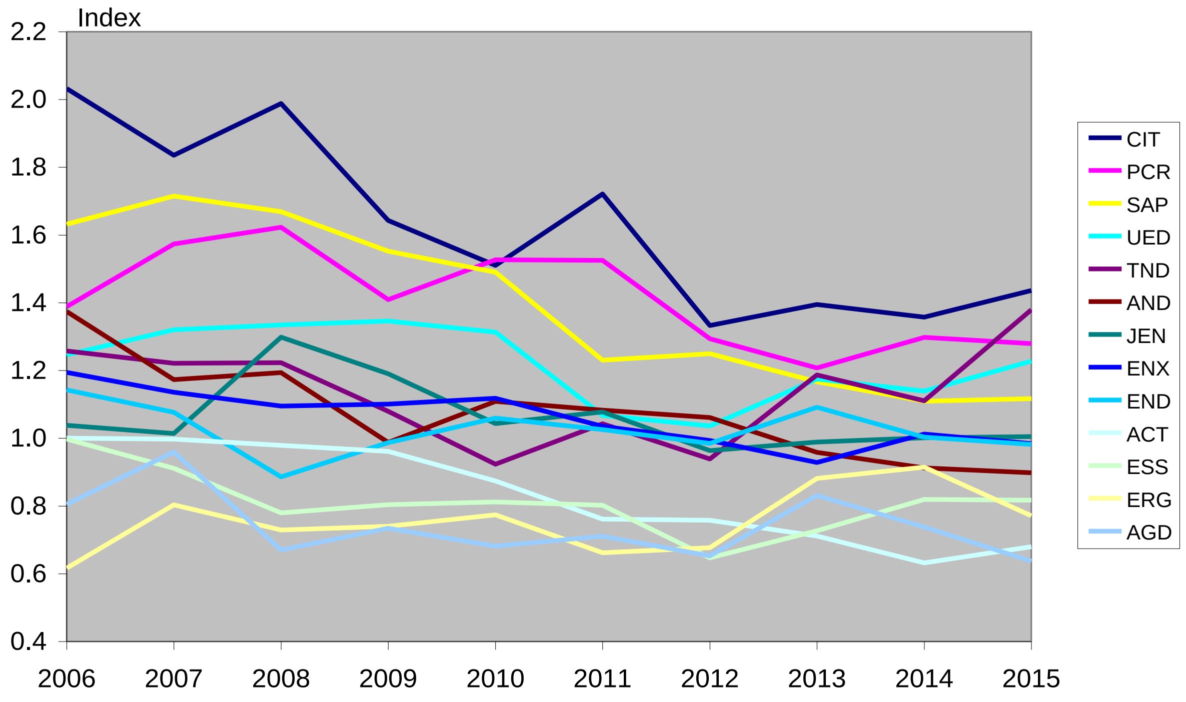
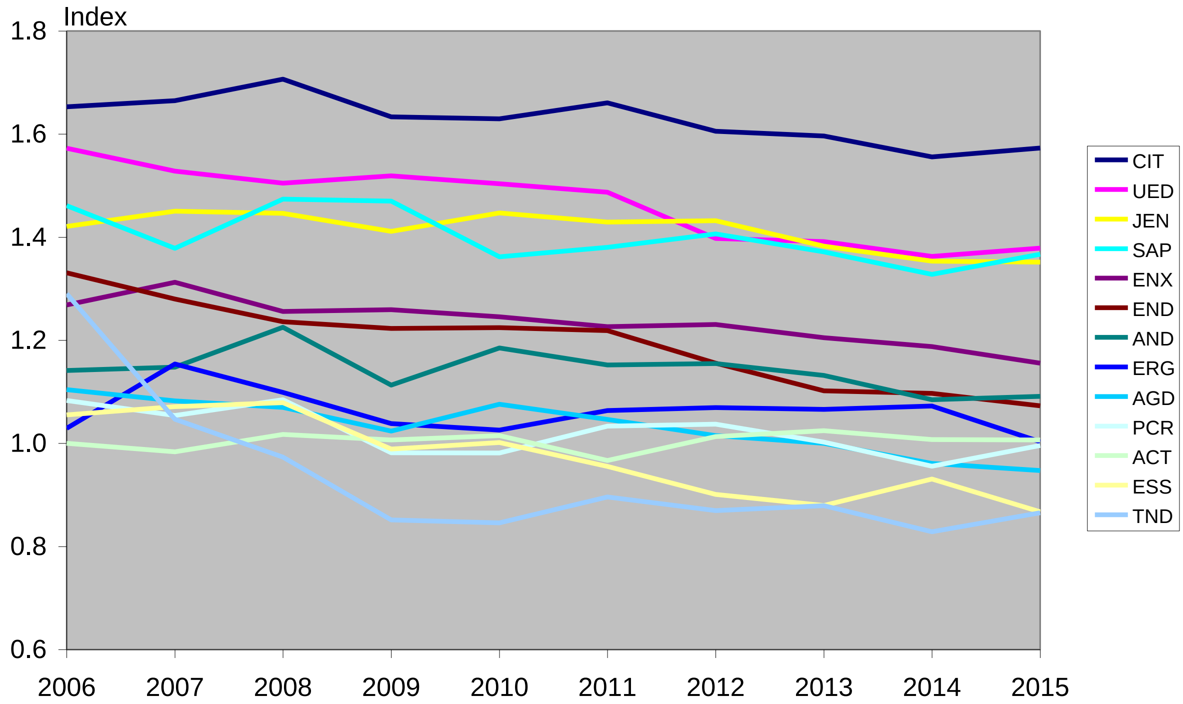


Figure 3 **DNSP multilateral capital partial factor productivity indexes, 2006–2015**



Distribution industry level output, input and TFP indexes and state level multilateral TFP indexes are presented in figures 4 and 5, respectively.

Figure 4 **Industry–level distribution output, input and total factor productivity indexes, 2006–2015**

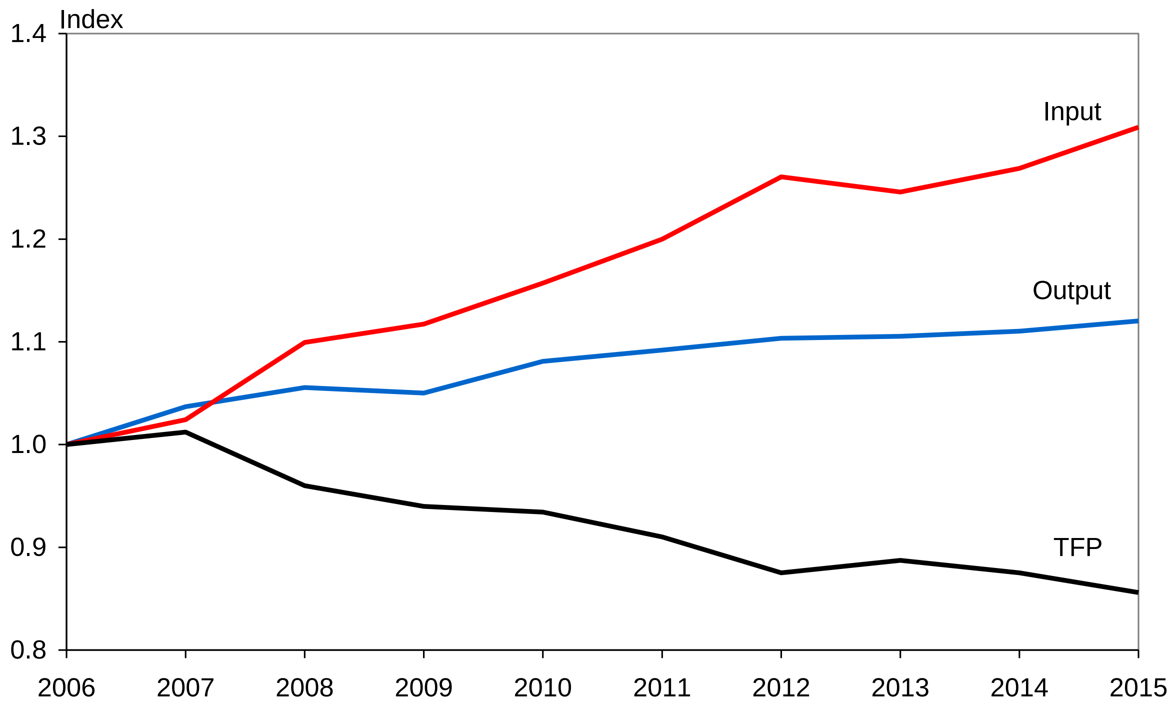
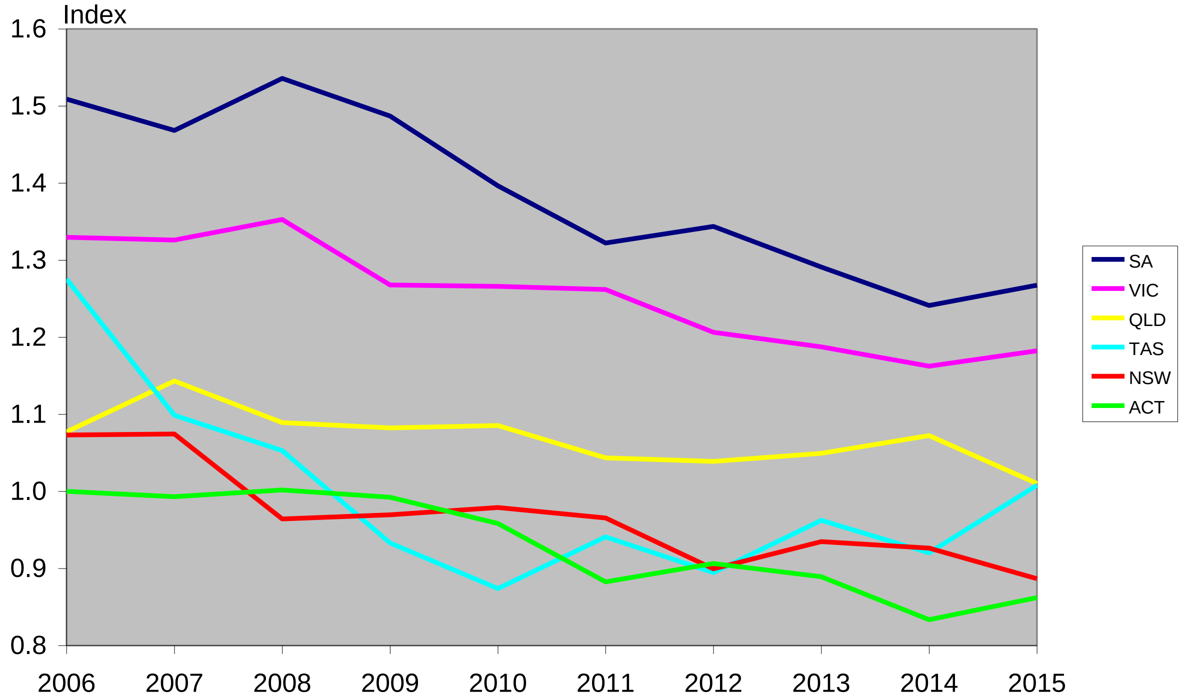


Figure 5 **State–level DNSP multilateral total factor productivity indexes, 2006–2015**



As noted in the preceding section, the current analysis uses data for ActewAGL based on its June 2013 revised CAM. This removes the outlier status of ActewAGL's previous capitalisation policy. The effect of this is to improve ActewAGL's relative performance on both MTFP and opex MPFP and to remove the need for a subsequent OEF adjustment as ActewAGL's capitalisation policy is now more in line with those of other DNSPs. It should be noted, however, that for presentation purposes all other scores are calibrated relative to the 2006 ActewAGL score which is set equal to one (as it is the first observation in the database). Hence, if ActewAGL's 2006 performance improves relative to what it was before while the performance of all other DNSPs remains the same as it was previously, ActewAGL's score will still be set equal to one and, because all other DNSPs' scores are calibrated relative to this now higher value, they will now receive lower scores. However, the relativities between all other DNSPs remain the same. It is only the relationship between each of the other DNSPs and ActewAGL that changes.

In the preceding section we also discussed the potential impact of removing Ausgrid's abnormal storm–related and voluntary redundancy costs in 2015. If these abnormal costs were only removed for Ausgrid and only for 2015, Ausgrid's opex MPFP score in figure 2 would increase from its current value of 0.64 to 0.81. This would move its ranking from last place to around equal tenth in 2015. However, as noted, a complete analysis would require these abnormal costs to be removed for all DNSPs and in all years.

Updated opex cost function results

As well as calculating MTFP and opex MPFP index–based efficiency results, Economic Insights (2014, 2015a,b) also estimated three econometric opex cost function models to examine DNSP opex efficiency. The three models estimated were:

- a least squares econometrics model using the Cobb–Douglas functional form (LSECD)
- a least squares econometrics model using the more flexible translog functional form (LSETLG), and
- a stochastic frontier analysis model using the Cobb–Douglas functional form (SFACD).

Unlike the non–parametric index–based MTFP and opex MPFP methods, econometric opex cost function models are able to allow for statistical noise in the data and produce confidence intervals.

A technical description of the models can be found in Economic Insights (2014). DNSP–specific dummy variables are included in the LSE models and opex efficiency scores are derived from these. In the SFA models opex efficiency scores are calculated in the model relative to the directly estimated efficient frontier.

Because there is insufficient time–series variation in the Australian data and an inadequate number of cross–sections to produce robust econometric results, we include data on New Zealand and Ontario DNSPs. We include country dummy variables for New Zealand and Ontario to pick up systematic differences across the jurisdictions, including particularly differences in opex coverage and systematic differences in OEFs, such as the impact of harsher winter conditions in Ontario. Because we include country dummy variables, it is not possible to benchmark the Australian DNSPs against DNSPs in New Zealand or Ontario. Rather, the inclusion of the overseas data was used to increase the number of observations in the sample to improve the robustness and accuracy of the parameter estimates.

The models include three outputs – ratcheted maximum demand, customer numbers and circuit length – along with the proportion of undergrounding and a time trend.

In this exercise we update the models in Economic Insights (2015b) to include data for 2014–15 (or 2015, as relevant) for the Australian and New Zealand DNSPs and 2014 data for the Ontario DNSPs. These models differ from the models in Economic Insights (2014, 2015a) in using non–coincident maximum demand as the basis for forming the ratcheted maximum demand output for all included DNSPs whereas the earlier models used coincident maximum demand in the calculation for Australian and New Zealand DNSPs. The effect of this change on efficiency scores was generally not material as there were offsetting changes in the country dummy variables.

The EBRIN data are used to update the database for the Australian DNSPs.

The parameter estimates and statistics for the updated SFACD, LSECD and LSETLG models are presented in tables 1, 2 and 3, respectively.

Average opex efficiency scores for the three opex cost function models are presented in figure 6 and table 4. Average opex MPFP efficiency scores are also included in the figure and table for reference.

Table 1 **SFA Cobb–Douglas cost frontier estimates using 2006–2015 data**

Variable	*Coefficient*	*Standard error*	*t–ratio*
ln(Custnum)	0.772	0.074	10.380
ln(CircLen)	0.093	0.039	2.360
ln(RMDemand)	0.128	0.065	1.950
ln(ShareUGC)	–0.142	0.032	–4.490
Year	0.020	0.001	13.370
Country dummy variables:			
New Zealand	0.074	0.094	0.780
Ontario	0.229	0.082	2.780
Constant	–30.027	2.959	–10.150
Variance parameters:			
Mu	0.377	0.064	5.890
SigmaU squared	0.034	0.008	4.235
SigmaV squared	0.010	0.001	17.469
LLF			470.230

Table 2 **LSE Cobb–Douglas cost function estimates using 2006–2015 data**

Variable	*Coefficient*	*Standard error*	*t–ratio*
ln(Custnum)	0.722	0.062	11.710
ln(CircLen)	0.106	0.028	3.720
ln(RMDemand)	0.174	0.060	2.890
ln(ShareUGC)	–0.181	0.021	–8.400
Year	0.021	0.002	8.480
Country dummy variables:			
New Zealand	–0.422	0.059	–7.180
Ontario	–0.228	0.057	–4.010
DNSP dummy variables:			
AGD	–0.053	0.113	–0.470
CIT	–0.782	0.087	–9.020
END	–0.350	0.077	–4.520
ENX	–0.414	0.067	–6.200
ERG	–0.292	0.099	–2.950
ESS	–0.431	0.104	–4.150
JEN	–0.520	0.083	–6.290
PCR	–0.895	0.083	–10.810
SAP	–0.689	0.082	–8.400
AND	–0.658	0.082	–7.990
TND	–0.658	0.096	–6.880
UED	–0.737	0.080	–9.150
Constant	–31.249	4.887	–6.390
R–Square			0.994

Table 3 **LSE translog cost function estimates using 2006–2015 data**

Variable	*Coefficient*	*Standard error*	*t–ratio*
ln(Custnum)=x1	0.615	0.070	8.800
ln(CircLen)=x2	0.100	0.029	3.440
ln(RMDemand)=x3	0.258	0.061	4.190
x1*x1/2	–0.259	0.308	–0.840
x1*x2	0.185	0.096	1.910
x1*x3	0.095	0.235	0.400
x2*x2/2	–0.015	0.038	–0.390
x2*x3	–0.160	0.076	–2.100
x3*x3/2	0.119	0.188	0.630
ln(ShareUGC)	–0.164	0.025	–6.450
Year	0.021	0.002	8.910
Country dummy variables:			
New Zealand	–0.503	0.059	–8.480
Ontario	–0.335	0.057	–5.880
DNSP dummy variables:			
AGD	–0.292	0.123	–2.380
CIT	–0.825	0.084	–9.830
END	–0.520	0.080	–6.480
ENX	–0.614	0.077	–8.020
ERG	–0.378	0.117	–3.230
ESS	–0.576	0.124	–4.630
JEN	–0.466	0.090	–5.180
PCR	–0.997	0.085	–11.680
SAP	–0.832	0.088	–9.500
AND	–0.724	0.086	–8.420
TND	–0.663	0.094	–7.060
UED	–0.741	0.093	–7.980
Constant	–32.375	4.778	–6.780
R–Square			0.994

There are several important differences across the various models. The opex cost function models include allowance for the key network density differences and the degree of undergrounding. The opex MPFP model includes allowance for the key network density differences but not the degree of undergrounding. The opex cost function models include three outputs whereas the opex MPFP model includes five outputs (the same three as the opex cost function models plus energy delivered and reliability). The opex cost function models use parametric methods whereas the opex MPFP model uses a non–parametric method. The LSE opex cost function models use least squares (line of best fit) estimation whereas the SFACD model uses frontier estimation methods. The LSE opex cost function models include allowance for heteroskedasticity and autocorrelation whereas the SFACD model does not. Despite all these differences in model features, the opex efficiency scores produced by the four models are broadly consistent with each other. They are also close to the results presented in Economic Insights (2015b) for the period up to 2014. ActewAGL's efficiency scores increase somewhat with the removal of its anomalous capitalisation policy with adoption of its June 2013 revised CAM.

Figure 6 **DNSP average opex cost efficiency scores, 2006–2015**

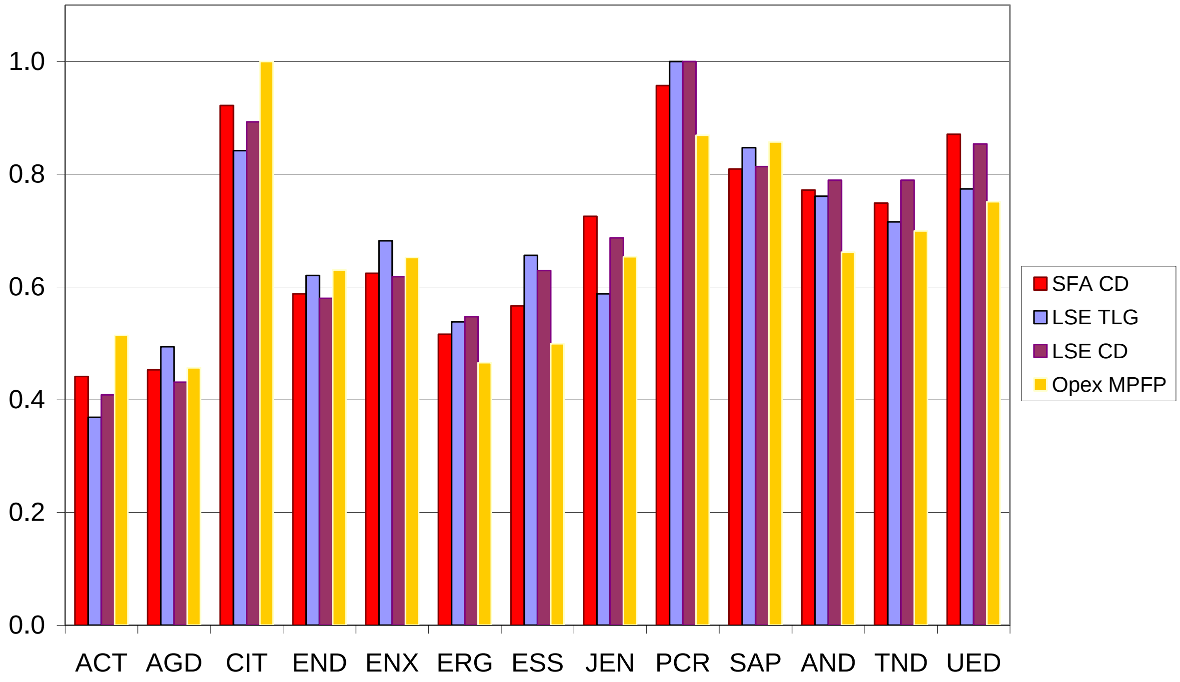


Table 4 **DNSP average opex cost efficiency scores, 2006–2015**

DNSP	*SFACD*	*LSETLG*	*LSECD*	*Opex MPFP*
ACT	0.441	0.369	0.409	0.514
AGD	0.453	0.494	0.431	0.457
CIT	0.922	0.842	0.893	1.000
END	0.588	0.620	0.580	0.630
ENX	0.624	0.682	0.618	0.652
ERG	0.516	0.538	0.547	0.466
ESS	0.566	0.656	0.629	0.499
JEN	0.725	0.588	0.687	0.653
PCR	0.957	1.000	1.000	0.869
SAP	0.810	0.847	0.814	0.857
AND	0.772	0.761	0.789	0.662
TND	0.749	0.716	0.789	0.699
UED	0.871	0.774	0.854	0.751

As noted above – and consistent with the approach adopted in Economic Insights (2014, 2015a) – allowance would have to be made for additional OEFs not included directly in the models and a margin for residual data and modelling limitations included before regulatory decisions can be made based on the analyses.

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