15 March 2013

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AEMC

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Dear Zaeen

SCER request for advice on differences between actual and forecast demand in network regulation

Thank you for the opportunity to respond to your workshop discussion paper following the request for the AEMC's advice on differences between actual and forecast demand in network regulation.

We will use this response to provide information that was requested of us during the forum held in Melbourne on 28 February, and also to reiterate the points that Bruce Mountain made on behalf of the EUAA at that Melbourne forum.

Firstly in response to the information request, Table 1 below shows our estimate of augmentation expenditure as a percentage of total capex for distribution and transmission in the NEM. The figure for distribution (in the second column) is the average annual allowed capex during the regulatory periods for all NEM distributors (excluding Aurora). The figure for transmission is the average annual *actual* capex (where known) and regulatory allowances (where actual data is not available) for the period 2003 to 2013 for transmission network service providers.

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Table 1. Average annual capex and augmentation capex per year

	Distribution (average allowed per year in current regulatory period) ($million)	**Transmission** (average per year 2003 to 2013) ($million)
Augmentation capex	$2,156	$739
Total capex	$8,192	$1,237
Augmentation capex as percentage of total capex	26%	60%

The results in Table 1 show that augmentation capex as a percentage of total capex is a little over 25% in distribution, but much larger (around 60%) in transmission. In addition, the percentage of augmentation capex in distribution (shown in Table 1) is likely to be an under-estimate as it shows augmentation capex as a percentage of total capex, which is before deduction of customer contributions for connections. Reliable data on customer contributions for connection was not available to us across all distributors in the NEM. However as an indication of what it might be, in Victoria assuming customer contributions covered forecast connection capex, the percentage of augmentation capex rises from 21% to 31%. As a broad estimate, we would therefore surmise that augmentation capital expenditure is around a third of (net) capex.

Our conclusion from this, as Bruce Mountain suggested at the forum, is that augmentation capital expenditure has been a significant proportion of total capex. This should be no surprise to many including the AEMC, considering the significant attention that has been paid to network augmentation as an explanation for higher expenditure and hence higher prices.

Now, to reiterate the EUAA's main points in response to the AEMC's workshop discussion paper, our perspectives are as follows:

1. Actual demand has been considerably lower than forecast demand in all regions of the NEM since 2009. This is true for peak demand as for average demand. We have attached (in Attachment A) a recent report by CME that examines this issue (amongst others) in transmission.
2. The EUAA has consistently brought to the AER's attention its concern that network service providers have proposed (and the AER accepted) excessively ambitious demand growth projections. The EUAA has done this through submissions to network service provider regulatory proposals and also AER draft decisions. The gap between actual demand and forecast demand is now significant. We have attached (in Attachment B) the EUAA's submission to the AER on its Draft Decision on allowed revenues for Electranet, as evidence of this gap in South Australia. Evidently the EUAA's concerns have been demonstrated to be well-founded.
3. Augmentation expenditure has been a significant proportion of total expenditure (as shown in Table 1).

Bringing these observations together we submit that, prima facie, there is evidence to suggest that there are large amounts of excess capacity in distribution and transmission in the NEM; that this has resulted in significant cost to users; and that this was avoidable.

Considering the evidence of excessive demand forecasts by NSPs and particularly that the EUAA has consistently brought this to the attention of the AER and network service providers, we think that adjustments should be made so that end users are not unfairly burdened through the recovery (including a financial return) of expenditure that has been inefficiently incurred. We submit that this is necessary to achieve the AEMC's instructions that "*… in considering potential amendments, the AEMC has regard to the need for actions to be proportionate, and not to compromise the ability of the regulatory frameworks to deliver the National Electricity Objective and meet the revenue and pricing principles".*

Such adjustments could take many forms including by placing the value of excessive investment in an escrow account and only allowing it to re-enter the regulated asset base (at its depreciated value) once it is used and useful. This is common practice in the regulation of utilities in North America.

Additional adjustments should be considered. This might include re-opening revenue and price control decisions so that end users obtain relief from demand forecasting errors sooner rather than later. Such revenue control re-opening might be avoided where governments continue to own NSPs, by the respective state governments instructing their representative NSP Boards to pass on savings that will be achieved as a result of lower demand than forecast.

We appreciate that the AEMC is constrained in its ability to analyse these issues in detail, in view of the urgency of its advice sought by SCER. On the basis of the available evidence we call on the AEMC to recommend to SCER that this issue be properly investigated having regard to adjustments such as we have proposed.

Finally, on the issue of differences between expected and actual revenue recovered in the case of DNSPs subject to price caps, we support a thorough investigation of this and call on the AEMC to advise SCER accordingly.

Yours sincerely

Brian Green
Chairman

Attachment A: CME, October 2012. *A comparison of outcomes delivered by electricity transmission network service providers in the National Electricity Market. A report for the Energy Users Association of Australia.*

Attachment B: EUAA, February 2013. *EUAA submission on Electranet 2013 to 2017 revenue determination.*

A comparison of outcomes delivered by electricity transmission network service providers in the National Electricity Market

A report for the Energy Users Association of Australia

carbon + energy markets

This project was partially funded by the Consumer Advocacy Panel (www.advocacypanel.com.au) as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas. The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission.

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EXECUTIVE SUMMARY

This document compares the outcomes delivered by transmission network service providers (TNSPs) operating in the National Electricity Market. It analyses publicly available data on revenue, expenditure, assets, demand and energy delivered.

The terms of reference for this study is to provide information that will be useful to energy users and other stakeholders in understanding the extent to which TNSPs are delivering outcomes that are in the long-term interests of energy users.

This paper follows on from our previous papers, "*Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors*" and "*Comparing electricity distribution network revenues and costs in New South Wales, Great Britain and Victoria*" (with Professor Stephen Littlechild) and adopts a similar analytical approach.

The TNSPs examined are Powerlink in Queensland, TransGrid in New South Wales, Electranet in South Australia, SP Ausnet (and VENCorp)[i] in Victoria and Transend in Tasmania. Each of these service providers have monopolies over the provision of transmission services in their states and territories. The Murraylink and Directlink TNSPs have not been included because they are single-asset service providers.

It should be stressed that this paper does not purport to be an econometric comparative assessment. Its analysis can not support precise conclusions on the relative efficiency and productivity of NSPs in the NEM.

The main findings in this paper are as follows:

1. In all regions of the NEM other than Victoria, regulated revenues of the transmission network service providers have increased at compound annual growth rates (in real terms) of at least 5% over the last decade.
2. In Queensland, operating expenditure has increased significantly, whereas the operating expenditure of the TNSPs in other states increased less significantly.
3. The main reason for the large (and growing) difference in regulated revenues is large (and growing) differences in the size of the regulated asset base. The main reason for the difference in the regulated asset base is much higher levels of capital expenditure in all regions of the NEM other than Victoria.
4. Other than in Queensland, non-load driven capex has not been particularly volatile. Even normalised by energy delivered, in Queensland non-load driven capex has been around twice as high as in the lowest states (New South Wales and Victoria).
5. There is a big gap in the performance of all TNSPs relative to Victoria in respect of load-driven capex. The average annual load-driven capex per MW of load growth over the period from 2005 to 2012 has been around $0.15m per MW in Victoria, around $2.5m/MW in Queensland, $0.9m / MW in South Australia, $1.8/MW in New South Wales and $5.6m / MW in Tasmania.

6. A significant part of the explanation for higher load-driven capex per MW of load growth appears to be demand forecasts that have consistently been higher than actual demand. Again this appears to be the case in all NEM regions except Victoria.

The conclusions that can be drawn from these observations are as follows:

- The provision of transmission network services in Victoria has been consistently better than in other states in respect of regulated revenues, the size of the regulated asset base, and the level of operating expenditure and capital expenditure. The most significant gap however is in respect of load-driven capex.
- Economies of scale (or more precisely higher through-put in the larger networks (in Victoria, NSW and QLD) may explain part of the gap with the networks in the smaller states (South Australia and Tasmania). But this does not explain why expenditure has risen so much in all states except Victoria.

This paper has not sought to explore exogenous factors (other than demand growth) that might explain the difference between Victoria and the TNSPs in other states. Some TNSPs have alluded to the legacy of historic investments in Victoria as explaining the difference between the apparently better performance of SP Ausnet.[ii] We have not attempted to test this claim rigorously. However, prima facie, it seems implausible.

In addition, generation expansion or closure would not seem to explain higher transmission expenditure. There has been limited new generation investment in the NEM over the period of this study. The largest generation expansion over the last decade – the Kogan Creek and Milmerran power stations – were commissioned at the start of this study period and hence transmission augmentations associated with this, will have been counted in previous periods. We understand that the Braemar 2, Darling Downs and Mount Stuart power stations have not of themselves required significant augmentation of the shared network. Similarly, wind farm development in South Australia and OCGT development in Western Victoria has not, we understand, necessitated substantial augmentation of the shared network. Investment in Open Cycle Gas Turbine capacity close to the regional reference nodes in most cases has not driven network augmentation. Neither has there been significant augmentation of interconnector capacity that might have necessitated significant intra-regional augmentation. As such, the broad conclusion seems to be that the limited generation expansion that has occurred in the NEM over the last decade does not seem to explain the transmission capex outcomes in aggregate or for individual TNSPs.

Ownership

In our report "*Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors*" we concluded that differences in ownership, and consequential impacts for investment incentives and regulation seemed to explain a significant part of the difference in the performance of the Distribution Network Service Providers (DNSPs).

The relative performance of transmission network service providers also seems to be drawn along ownership lines: transmission network service provision in Victoria is privatised and appears to have consistently delivered better outcomes than seems to be the case where governments own the network service providers.

On the other hand, the performance of Electranet, which is nominally privately owned, is comparable to the government-owned NSPs, rather than to SP Ausnet. This seems to undermine the conclusion that ownership is an explanatory factor for performance differences across the sector.

However Electranet's nominal classification as a privately owned TNSP does perhaps not fully reflect the incentives that its shareholders provide. Electranet's dominant shareholder (41% shareholding) is Powerlink, the Queensland transmission network service provider. Electranet's nine person Board is chaired by the previous Chief Executive of Powerlink. Three of the remaining eight Electranet Board members are employees of Powerlink including Powerlink's current Chief Executive Officer, its Chief Operating Officer and its Chief Financial Officer. So, although Electranet is nominally a private company, Powerlink's part ownership, and the presence of Powerlink's most senior past and present executives on its Board of Directors, calls into question whether Electranet has the same financial incentives as might be associated with a conventional, privately owned utility.

If Electranet is, de facto, to be classified as a government-owned NSP, then it would appear that government/private ownership differentiation of TNSPs as an explanation for comparative performance, conforms to the conclusions in our report *Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors* in relation to the impact of ownership on the outcomes delivered by DNSPs.

Planning

A second major area of differentiation between Victoria and the TNSPs in other states is in respect of the institutional arrangements and methodologies for network planning. AEMO is responsible for planning the augmentation of the Victorian transmission network, while planning is integrated with asset ownership for the other TNSPs. AEMO (and VENCorp before it) uses a different planning methodology – a cost/ benefit assessment – while other TNSPs use "deterministic" approaches, that do not systematically quantify benefits against costs in planning augmentations to the network.

There have been many debates amongst market participants, network service providers, regulators and market operators on the merits of the different planning methodologies and different institutional arrangements for network planning in the NEM.

The empirical assessment of outcomes over the last 10 years, as shown in this paper, suggests that the Victorian arrangements have delivered better outcomes for energy users. This is most clearly observable in lower augmentation expenditure and the evidence that demand forecasting errors in Victoria have not been as large as they appear to have been in New South Wales and Queensland.

It might be concluded that the Victorian planning arrangements, relative to those in New South Wales and Queensland, have reduced the prospect that energy users are charged for expenditure that evidently has not been required. Governments in other states might be encouraged to have closer regard to the Victorian arrangements.

Table of Contents

1 **Introduction** **10**

2 **Regulated revenue, operating expenditure, assets, capital expenditure** **11**

2.1 **Revenues** **11**

2.2 **Operating expenditure** **13**

2.3 **Assets** **14**

2.4 **Capital expenditure** **16**

2.4.1 Non load driven capex 17

2.4.2 Load driven capex 18

3 **Discussion** **21**

GLOSSARY

ACCC	Australian Competition and Consumer Commission
AER	Australian Energy Regulator
AEMC	Australian Energy Markets Commission
CAGR	Compound Annual Growth Rate
DNSPs	Distribution Network Service Providers
MW	Mega Watt
MWh	Mega Watt Hour
NEM	National Electricity Market
RAB	Regulated asset base
TNSP	Transmission network service provider

List of Figures

Figure 1. Maximum Allowed Revenues (2011$million) 11

Figure 2. Peak demand (MW) by NEM region (left hand); trend rate of growth in peak demand and average demand (MW) 12

Figure 3. Maximum Allowed Revenues (2011$ million) per MWh of energy delivered 12

Figure 4 Compound Annual Growth Rates of regulated revenue, and normalised for growth in delivered energy and peak demand from 2005 to 2013 13

Figure 5. Operating expenditure (2011$million) 13

Figure 6. Operating expenditure per unit of energy delivered (2011$thousands per MWh) 14

Figure 7. Regulated asset base (2011$millions) 14

Figure 8. Regulated asset base (2011$million) per MW of peak demand and per MWh of energy delivered 15

Figure 9. Compound annual growth rate of the regulated asset base of transmission service providers for the period 2005 to 2013 (2011$) (left chart); and trend growth in RAB divided by trend (annual) growth in peak demand from 2005 to 2012 (right chart) 15

Figure 10. Compound Annual Growth Rate of the RAB, and normalised for growth in energy delivered and peak demand, from 2005 to 2013 16

Figure 11. Capital expenditure (2011$thousands) 16

Figure 12. Average annual load-driven capex and non-load driven capex (2011$million) 17

Figure 13. Non-load driven capex (2011$million) 17

Figure 14. Average annual non-load driven capex divided by average annual energy 18

Figure 15. Load-driven capex (2011$million) 18

Figure 16. Average annual load driven capex divided by average annual demand growth 19

Figure 17. Average annual difference between projected and actual peak demand (MW) over the period from 2006/2007 to 2011/2012 20

1 Introduction

This document compares the outcomes delivered by transmission network service providers (TNSPs) operating in the National Electricity Market (NEM). It analyses publicly available data on revenue, expenditure, assets, demand and energy delivered.

The terms of reference for this study is to provide information that will be useful to energy users and other stakeholders in understanding the extent to which TNSPs are delivering outcomes that are in the long-term interests of energy users. This paper follows on from our previous papers, "*Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors*" and "*Comparing electricity distribution network revenues and costs in New South Wales, Great Britain and Victoria*" (with Professor Stephen Littlechild) and adopts a similar analytical approach.

The TNSPs examined are Powerlink in Queensland, TransGrid in New South Wales, Electranet in South Australia, SP Ausnet (and VENCorp)[iii] in Victoria and Transend in Tasmania. Each of these service providers have monopolies over the provision of transmission services in their states and territories. The Murraylink and Directlink TNSPs have not been included because they are single-asset service providers.

The Australian Energy Regulator (AER) and its predecessor, the Australian Competition and Consumer Commission (ACCC), regulated all the TNSPs in this study over the study period. In this analysis all financial figures are presented in constant currency (2011 dollars) and for financial years ending 30 June.

The next section examines regulated revenues, operating expenditure, assets and capital expenditure. The last section discusses the data and draws out relevant conclusions.

It should be stressed that this paper does not purport to be an econometric comparative assessment. Its analysis can not support definitive conclusions on efficiency and productivity, and it is not intended to do this.

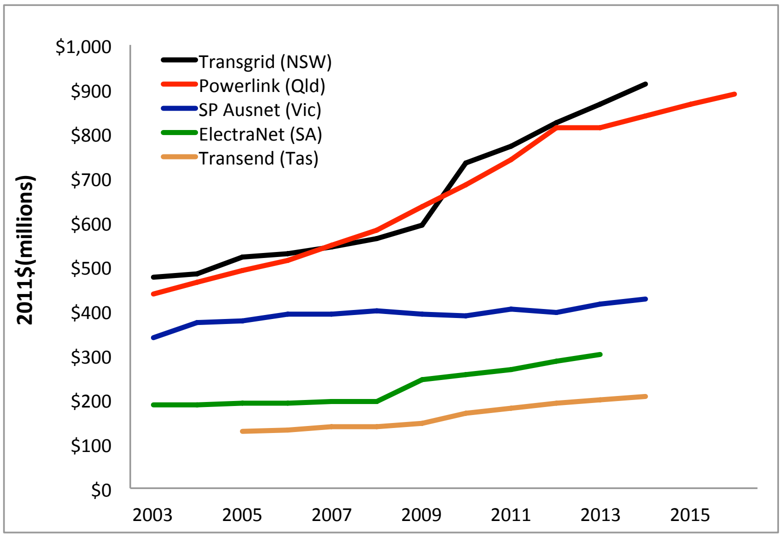
2 Regulated revenue, operating expenditure, assets, capital expenditure

In this section we compare the revenues, operating expenditure, assets and capital expenditure of the network service provides in the five NEM regions. The situation in Victoria is a little complicated in that AEMO (previously VENCorp) procures the augmentation of the network (and is the registered Transmission Network Service Provider for Victoria) while SP Ausnet operates and develops the remaining transmission assets. The regulated revenues that AEMO collects for this activity are known (the AER regulates them), but their actual expenditure in these activities is not publicly known, and neither are their assets or liabilities (the contracts that they have entered into). We have had to estimate this in order to complete this analysis. In the charts and figures that follow in this section, for the sake of brevity "SP Ausnet" also include the relevant amounts associated with AEMO's network expansion activities in Victoria. The need to estimate these AEMO data introduces some unavoidable error into this analysis. However this error is likely to be small considering the small size of AEMO's expansion procurement activities in Victoria compared to SP Ausnet or indeed of any of the TNSPs in other NEM regions.

2.1 Revenues

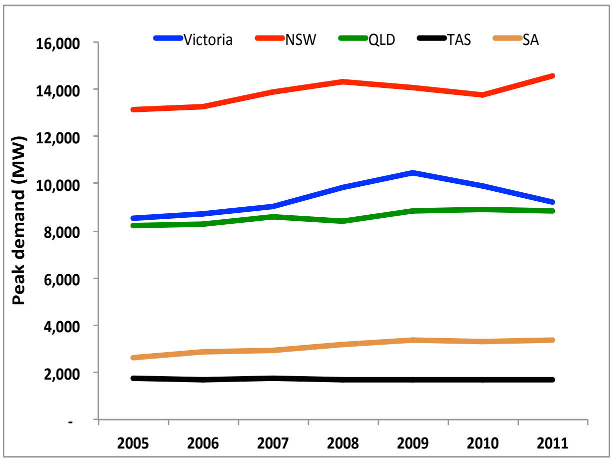
Figure 1 shows the maximum allowed revenues (as determined the ACCC/AER) for the five TNSPs over the period from 2003 to 2015. It shows that the annual revenues for TransGrid and Powerlink have roughly doubled, for Electranet and Transend they have increased by about 50% and for SP Ausnet about 20%.

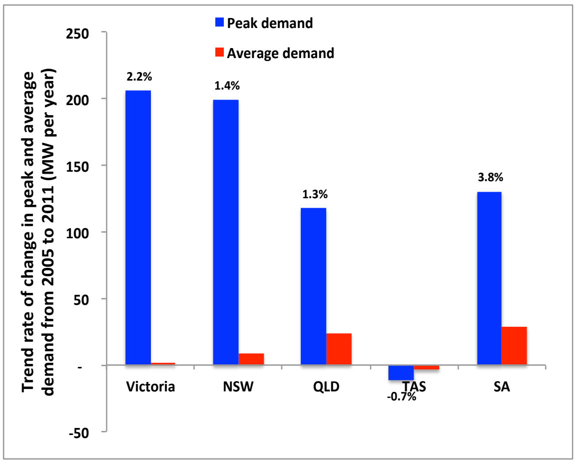
Figure 1. Maximum Allowed Revenues (2011$million)[iv]



The charts in Figure 2 show the trend of the peak demand (MW) in each region of the NEM, and trend rate of growth of peak and average demand. In the right hand chart, the data labels above the peak demand bars, is the peak demand growth as a percentage of the 2011 peak demand.

Figure 2. Peak demand (MW) by NEM region (left hand); trend rate of growth in peak demand and average demand (MW)

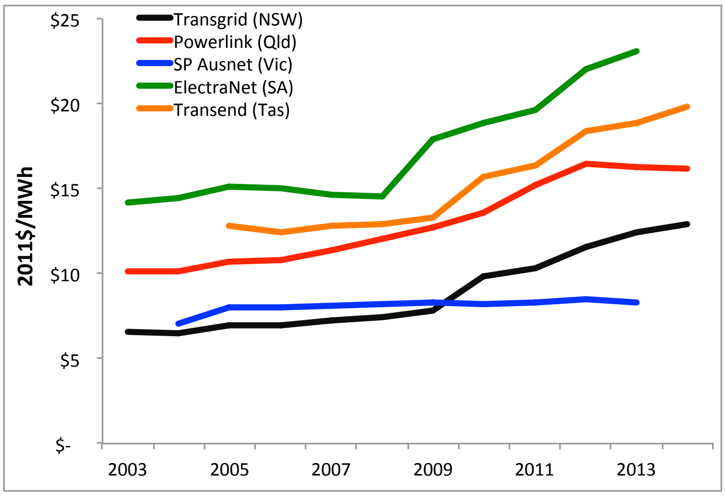




The chart in Figure 3 shows the regulated revenues normalised for energy delivered. It is clear from this that SP Ausnet recovers the lowest revenue per unit of delivered energy. At the other extreme, Electranet recovers more than three times as much revenue per MWh delivered, as SP Ausnet.

The gap between SP Ausnet and all other TNSPs has grown over this period. Also notable in this chart is that for all TNSPs there has been a step up in allowed revenues around 2008 and 2009. This reflects high allowed regulated revenues in the AER's most recent regulatory decisions, which took effect around that time.

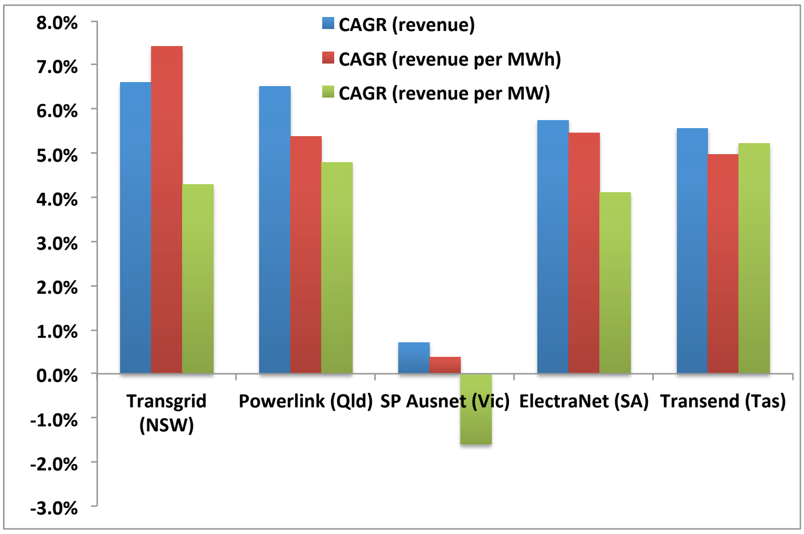
Figure 3. Maximum Allowed Revenues (2011$ million) per MWh of energy delivered[v]



The relative performance of the TNSPs can also be described by comparing the compound annual growth rates (CAGR) of their regulated revenues in absolute terms or normalised by energy delivered or annual peak demands. This is shown in Figure 4 for the period 2005 to 2013 (the period for which regulated revenue data is available for all TNSPs). The figure shows that TransGrid and Powerlink had the highest revenue growth rates, with TransGrid's Revenue Growth/MWh being the highest.

The green bars in Figure 4 shows the CAGR of revenue normalised for growth in demand.

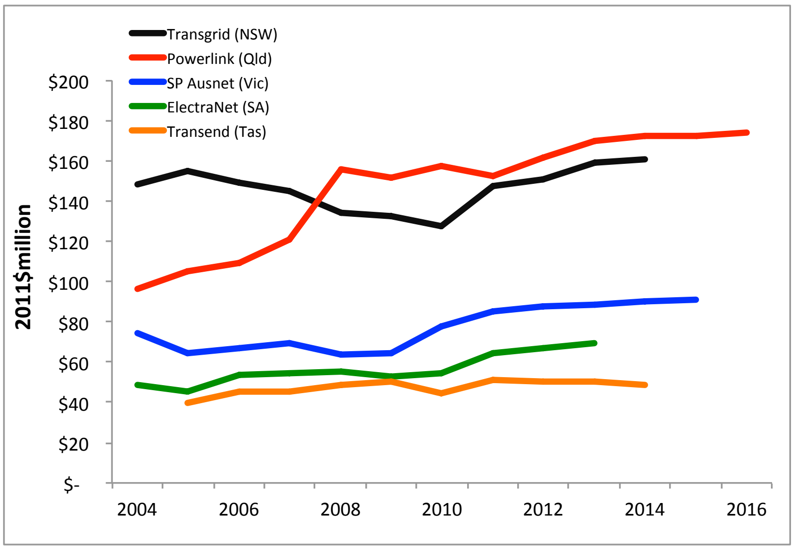
Figure 4 Compound Annual Growth Rates of regulated revenue, and normalised for growth in delivered energy and peak demand from 2005 to 2013[vi]



2.2 Operating expenditure

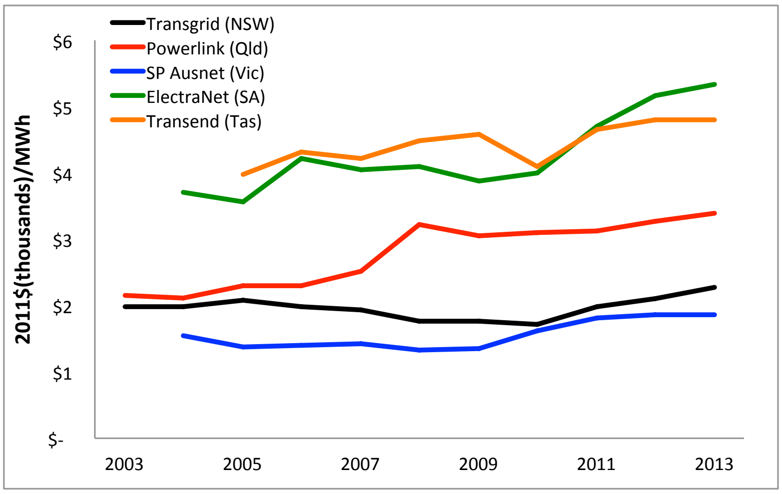
In the regulatory controls, the allowed revenue is the sum of an allowance for operating expenditure and allowances for depreciation of the Regulated Asset Base (RAB) and for a return on that RAB. The allowance for operating expenditure is shown in Figure 5. It is clear from this that, other than for Powerlink, operating expenditure has not grown significantly in real terms.

Figure 5. Operating expenditure (2011$million)[vii]



When normalised for energy delivered, as shown in Figure 6, the growth in operating expenditure by Powerlink is offset slightly by growth in energy delivered, while the growth in operating expenditure per unit of energy delivered is highest for Electranet. SP Ausnet has the lowest operating expenditure per unit delivered, at around a third per MWh delivered, as the highest.

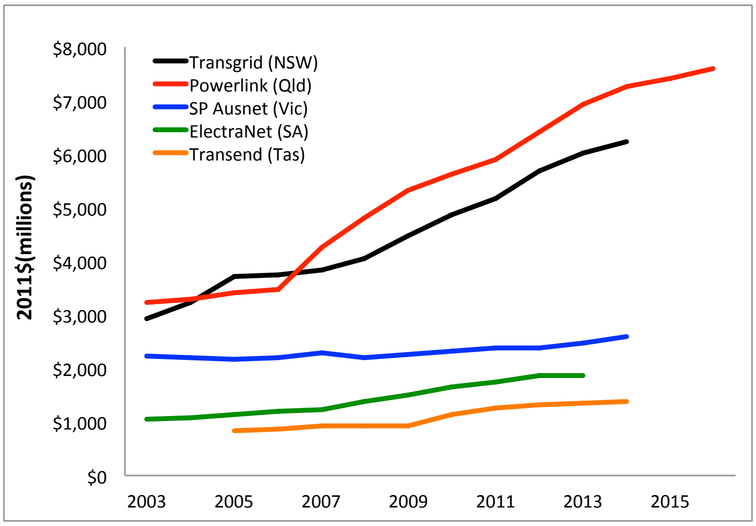
Figure 6. Operating expenditure per unit of energy delivered (2011$thousands per MWh)[viii]



2.3 Assets

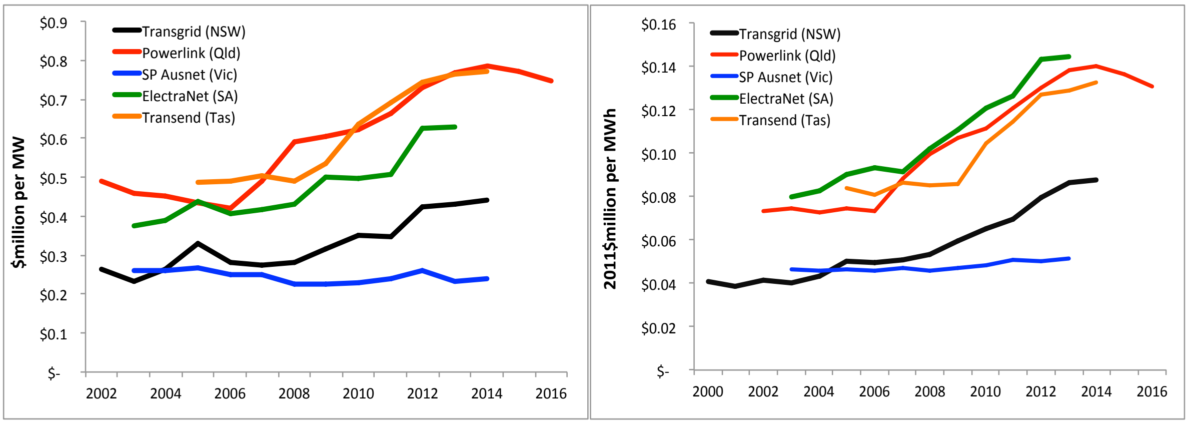
Figure 7 shows the change in the regulated asset base (RAB). The allowances for the return on assets are proportionate on the size of the RAB. This return on assets, plus the depreciation of the RAB, account for around three quarters of TNSP regulated revenues. Other than for SP Ausnet, there has been a significant increase in the RAB for all TNSPs. The RAB for TransGrid and Powerlink has approximately doubled, and for Electranet and Transend it has increased by around 50%.

Figure 7. Regulated asset base (2011$millions)[ix]



The charts in Figure 8 show the change in the RAB normalised for changes in the peak demand and delivered energy. SP Ausnet has the lowest RAB per unit of demand and per MWh delivered. By contrast, the RABs for all other TNSPs have grown significantly (approximately doubled for Electranet, TransGrid and Powerlink).

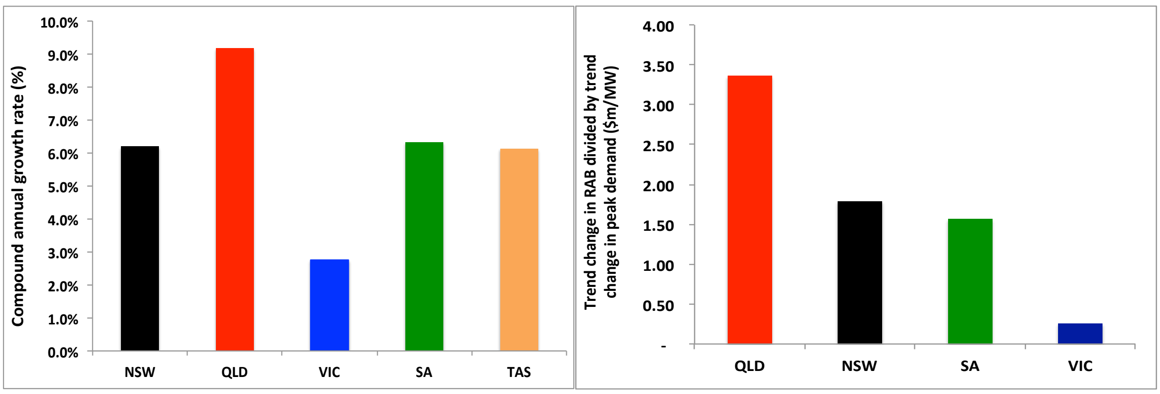
Figure 8. Regulated asset base (2011$million) per MW of peak demand and per MWh of energy delivered[x]



The left hand chart in Figure 9 is the compound annual growth rate from 2005 to 2013 of transmission service provider RABs[xi]. Over this period, the RAB grew around four times as quickly in QLD as in VIC, and the remaining transmission service providers had comparable rates of growth, roughly three times the rate in VIC.

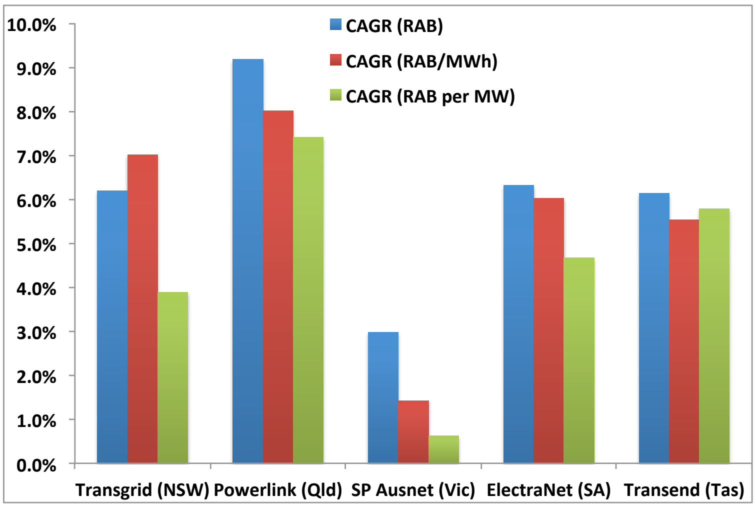
The right hand chart in Figure 9 is the trend change in the RAB from 2005 to 2012, divided by the trend change in the actual peak demand over this period. It shows that the differences between VIC and the other states are even greater when normalising the growth in the RAB for the growth in peak demand[xii].

Figure 9. Compound annual growth rate of the regulated asset base of transmission service providers for the period 2005 to 2013 (2011$) (left chart); and trend growth in RAB divided by trend (annual) growth in peak demand from 2005 to 2012 (right chart)



A summary table of the CAGR of the RAB and normalised for growth in peak demand and energy delivered for the period from 2005 to 2013 is shown in Figure 10. It is clear from this that the RAB for Powerlink has grown more strongly than for any of the other TNSPs in absolute terms, and after normalisation for energy delivered or annual peak demands. At the other end of the spectrum, the growth in the RAB for SP Ausnet has been the lowest in absolute terms and particularly after normalisation for growth in demand.

Figure 10. Compound Annual Growth Rate of the RAB, and normalised for growth in energy delivered and peak demand, from 2005 to 2013[xiii]



The main reason for the rapid expansion in the RAB for all TNSPs except SP Ausnet, has been increased capital expenditure. This increase has far exceeded the rate of depreciation of the RAB.

2.4 Capital expenditure

Figure 12 shows the capitalised expenditure for each TNSP from 2003 to 2013. It shows that SP Ausnet, Electranet, and Transend have each spent similar amounts. TransGrid and Powerlink have also spent similar amounts and on average about three to five times as much as SP Ausnet, Electranet, and Transend.

Figure 11. Capital expenditure (2011$thousands)[xiv]

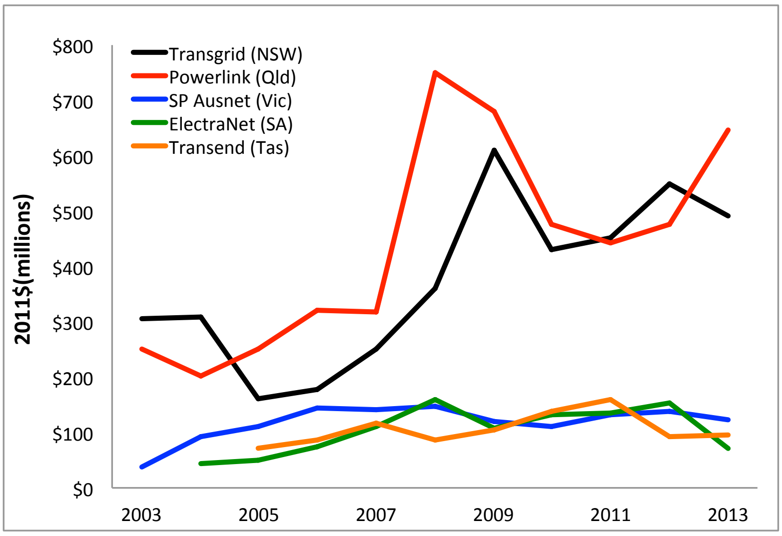
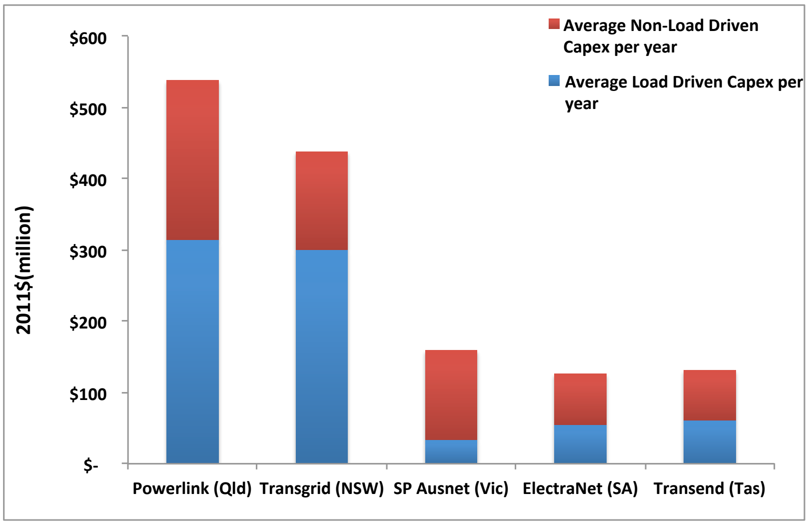


Figure 11 shows the split between average annual "load driven" capex and "non-load driven" capex, based on the proposals that TNSPs made to the AER at the time of their revenue control decisions.

Load driven capex is capitalised expenditure that arises through augmentation of the network (expanding the capacity of existing assets and/or building new ones) in order to meet actual or expected demand growth. "Non-load driven" capex covers expenditure on asset renewal, asset replacement (due to ageing or redundancy), security/compliance, IT, commercial buildings, motor vehicles, moveable plant and business support.

As a proportion of its total capex, SP Ausnet has the highest proportion of load driven capex. TransGrid has, proportionate to its total capex, the highest load-driven driven capex. As an average across the industry, around 40% of capex is not load-driven, and the remaining 60% is load driven.

Figure 12. Average annual load-driven capex and non-load driven capex (2011$million)[xv]



2.4.1 Non load driven capex

Figure 13 shows non load driven capex over the period from 2003 to 2015. Powerlink stands out from the other TNSPs, since 2007. Their non load driven capex also shows the greatest inter-annual variation – roughly a factor of nine difference between 2004 and 2012.

Figure 13. Non-load driven capex (2011$million)[xvi]

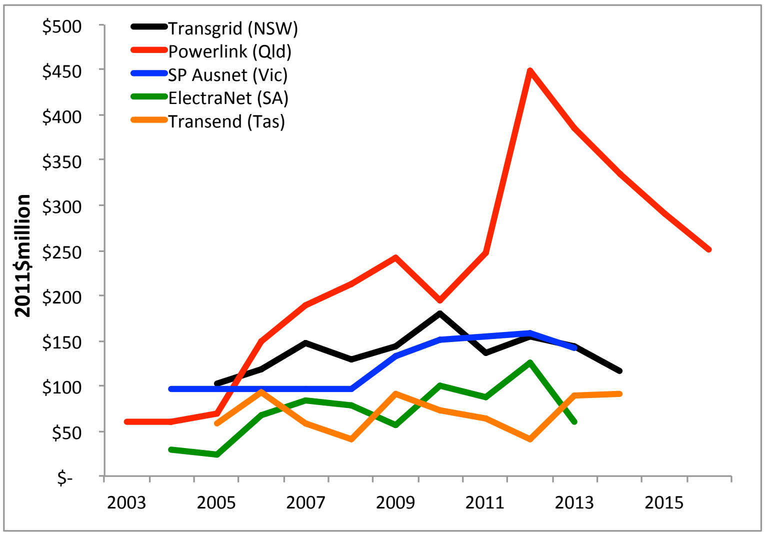
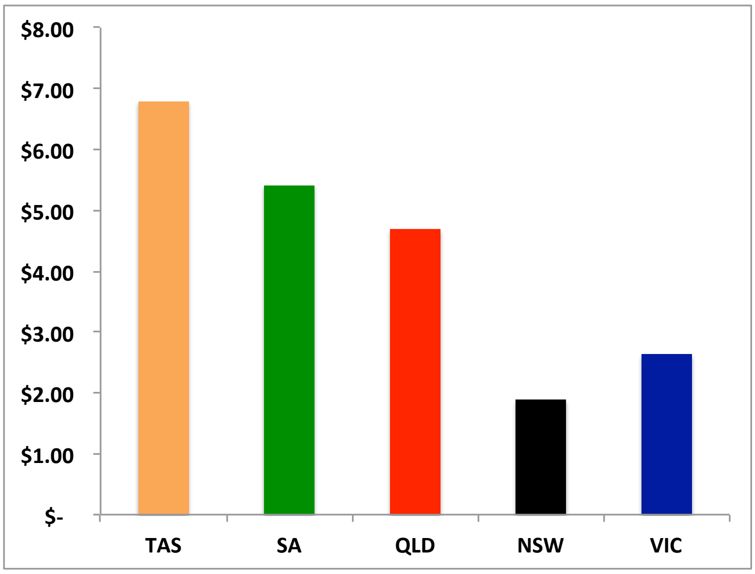


Figure 14 presents an analysis of the average annual non-load driven capex divided by average annual energy transmitted. It suggests economies of scale might explain the relatively higher ratios for Transend and Electranet (the networks with the lowest energy through-put). If the argument of economies of scale is used to explain the higher outcomes for Transend and Electranet, then this same argument suggests that Powerlink and SP Ausnet, with similar energy through-put (delivered energy) should have comparable levels of non-load driven capex, yet Powerlink's average annual non-load capex is more than double the level for SP Ausnet.

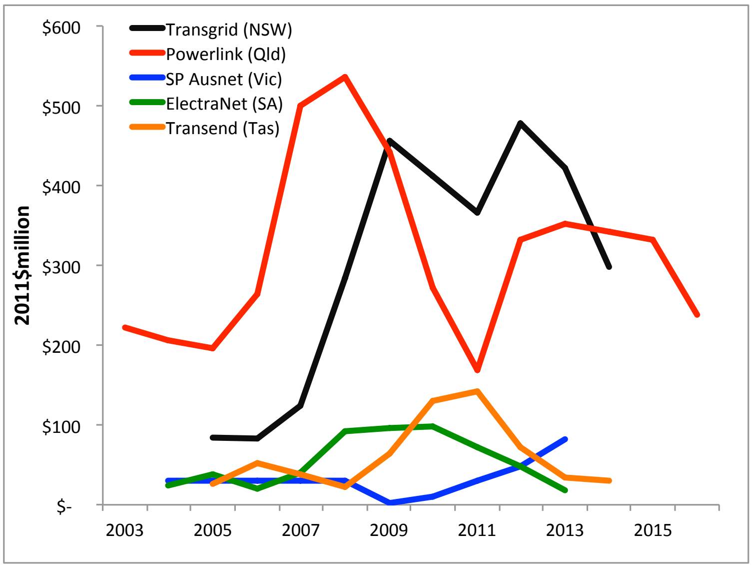
Figure 14. Average annual non-load driven capex divided by average annual energy[xvii]



2.4.2 Load driven capex

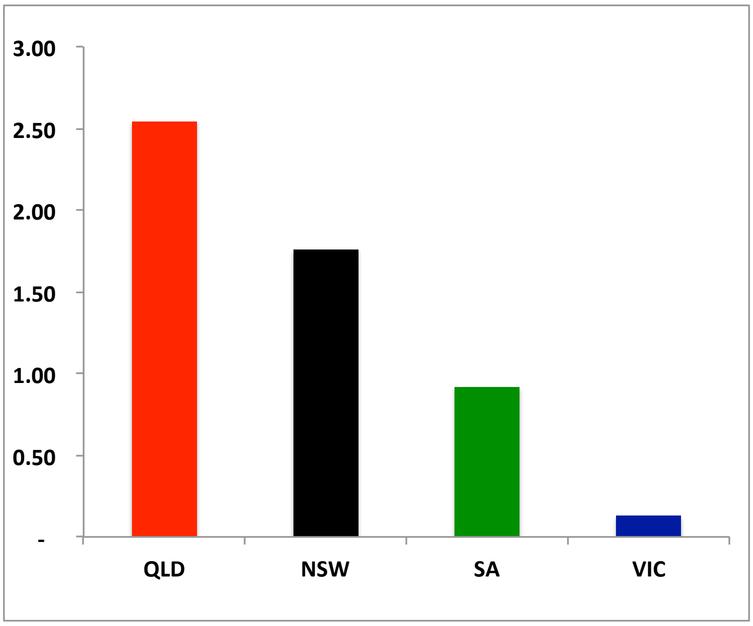
Figure 15 shows the load driven capex between 2003 and 2015.

Figure 15. Load-driven capex (2011$million)[xviii]



We have analysed the load driven capex in the context of the load growth over the period from 2005/6 to 2011/12 (the period for which load driven capex data is available and actual peak demand is known). The result of this analysis is shown in Figure 16. The outcome of this analysis is the average annual load-driven capital expenditure expressed as a ratio of the average annual load growth. Transend is not shown in this chart because it has had significant load-driven capital expenditure but almost no growth in the load and hence its ratio ($12m per MW of load growth) would distort the comparison of the remaining TNSPs if shown on the same chart. Figure 16 shows that Powerlink had the highest and Victoria by far the lowest, load driven capex per MW of actual load growth over this period.

Figure 16. Average annual load driven capex divided by average annual demand growth[xix]



The analysis in Figure 16 reflects the average annual load driven capex per unit of *actual* load growth, not the load growth projected by the TNSPs at the time they decided to incur the expenditure. The load-driven expenditure per unit of load growth would be different if *projected* load growth, rather than *actual* load growth, was used.

It should be recognised, as we alluded to in the introduction to this section, that there are some definitional and data challenges in these comparisons. For all TNSPs other than SP Ausnet, the annual load driven capex is based on actual load driven capex (to the end of their previous regulatory period) and the proposed load driven capex (for the current regulatory period), based on the information that the TNSPs' provided in their revised revenue proposals to the AER.

For SP Ausnet, the load driven capex is the augmentation capex that has been planned and procured by VENCorp (now AEMO). There may be definitional differences between what is classified as "augmentation capex" in Victoria and what the other TNSPs call "load driven capex".

As such, more effort in common data definitions may suggest that the differences between SP Ausnet and the other TNSPs may not actually be as large as shown in Figure 16, or indeed they may be larger. However, the gap between SP Ausnet and the others seems to be so large that even substantial definitional differences are unlikely to undermine the observation that the Victorian arrangements appear to have delivered much lower capex per MW of additional demand, than seems to be the case for any of the other TNSPs.

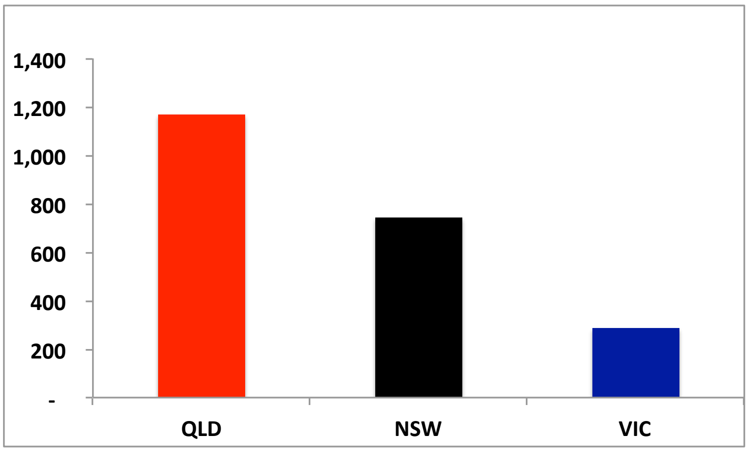
The size of the gap begs the question whether part of it can be attributed to demand forecasting errors - has VENCorp/ AEMO forecast demand more accurately than other TNSPs, and hence delivered lower capex per MW of demand ?

We analysed this, comparing the outcomes in Victoria with the outcomes in the other two major NEM regions – NSW and QLD. The results are presented in Figure 17. It shows the average annual difference, during the current regulatory period of each TNSP, of:

a) the annual peak demands that were projected by the TNSPs (using their medium growth 50% Probability of Exceedance projections) in their 2006/7 annual planning reports for the period from the year ending June 2007; and
b) the actual peak demand (up to the year ending 30 June 2012).

The result shows that the TNSPs in Queensland and New South Wales projected actual peak demand to be, on average, around 1,200 MW and 740 MW higher than it has been over this period, respectively. In Victoria, peak annual demand was on average 287 MW higher than the actual demand.

Figure 17. Average annual difference between projected and actual peak demand (MW) over the period from 2006/2007 to 2011/2012



The comparative demand forecasting inaccuracy in NSW and QLD, relative to VIC, would therefore explain part of the reason for their higher load driven capex per MW in NSW and QLD, compared to VIC.

3 Discussion

The main observations from the data in this paper can be summarised as follows:

1. In all regions of the NEM other than Victoria regulated revenues have increased strongly over the last decade: compound annual growth in real terms of at least 5% in absolute terms and per MWh delivered or per MW of peak demand.
2. In Queensland operating expenditure increased significantly, whereas the operating expenditure of the TNSPs in other states remained reasonably constant. Per MWh delivered, there is a significant difference between the lowest (in Victoria) and the highest (in South Australia and Tasmania). Economies of scale may explain part of this difference. However even for TNSPs with comparable levels of delivered energy, operating expenditure per MWh differs significantly. For example in Queensland twice as much operating expenditure per MWh delivered is recovered than in Victoria.
3. The main reason for the large (and growing) difference in regulated revenues is large (and growing) differences in the size of the regulated asset base. There is currently a factor of three difference between the value of the regulated asset base per MWh delivered for the lowest (in Victoria) and the highest (South Australia, Tasmania and Queensland). While economies of scale might explain some of the gap between Victoria on the one hand, and South Australia and Tasmania on the other, it does not seem to explain the large gap between Victoria and Queensland. Neither do economies of scale explain the widening gap between Victoria (whose RAB per MWh delivered has not increased significantly) and the other TNSPs (whose RAB per MWh have increase significantly).
4. The main reason for the large (and growing) difference in the regulated asset base is much higher levels of capital expenditure by some TNSPs than others. Capital expenditure in Tasmania and South Australia is split approximately evenly between load-driven and non-load driven categories. In both New South Wales and Queensland the TNSPs spend (on average) a greater proportion of their capital expenditure on non-load driven capex than they do on load driven capex. In Victoria proportionately more is spent on non-load driven capex than load-driven capex.
5. Other than in Queensland, non-load driven capex has not been particularly volatile. Even normalised by energy delivered, in Queensland non-load driven capex has been around twice as high as in the lowest states (New South Wales and Victoria).
6. There is a big gap in the performance of all TNSPs relative to Victoria in respect of load-driven capex. The average annual load-driven capex per MW of load growth over the period from 2005 to 2012 has been around $0.15m per MW in Victoria, around $2.5m/MW in Queensland, $0.9m / MW in South Australia, $1.8/MW in New South Wales and $5.6m / MW in Tasmania (which has incurred substantial load driven capital expenditure but where there has been negligible load growth).
7. A significant part of the explanation for higher load driven capex per MW of load growth appears to be demand forecasts that have consistently been higher than

actual demand. Over the period from 2006/7 to 2011/12, Victoria's demand forecasting error appears to have averaged around 290 MW per year. It was more than twice this in NSW and more than four times higher in QLD.

The conclusions that can be drawn from these observations are as follows:

- The provision of transmission network services in Victoria has been consistently better than in other states in respect of regulated revenues, the size of the regulated asset base, and the level of operating expenditure and capital expenditure. The most significant gap however is in respect of load-driven capex.
- Economies of scale (or more precisely higher through-put in the larger networks in Victoria, NSW and QLD) may explain part of the gap between Victoria, South Australia and Tasmania but this does not explain the growing gap between Victoria and the TNSPs in the other regions.

This paper has not sought to explore exogenous factors (other than demand growth) that might explain the difference between Victoria and the TNSPs in other states. Some TNSPs have alluded to the legacy of historic investments in Victoria as explaining the difference between the apparently better performance of SP Ausnet.[xx] We have not attempted to test this claim rigorously. However, prima facie, it seems implausible. If Victoria has a legacy of higher investment in the distant past, then while this may explain lower augmentation expenditure in the recent past the legacy of this higher historic investment should be reflected in a higher value of the regulatory asset base in Victoria than elsewhere. It is not: even in 2003, per MW, SP Ausnet appears to have had one of the lowest RABs.

Furthermore legacy factors would not seem to explain lower operating expenditure in Victoria, and is unlikely to explain lower non-load driven capex in Victoria. Finally legacy factors would not explain the demand forecasting errors of TNSPs, other than in Victoria, that seems to explain a part (possibly a large part) of their higher load driven capital expenditure.

The analysis so far has not considered the effect on transmission investment of new generation, or additional costs that might be associated with the closure of existing generation. There has been limited new generation investment in the NEM over the period of this study. The largest generation expansion over the last decade – the Kogan Creek and Milmerran power stations – were commissioned at the start of this study period and hence the associated transmission augmentations will have been counted in previous periods. We understand that the Braemar 2, Darling Downs and Mount Stuart power stations have not of themselves required significant augmentation of the shared network. Similarly, wind farm development in South Australia and OCGT development in Western Victoria has not, we understand, necessitated substantial augmentation of the shared network. Investment in Open Cycle Gas Turbine capacity close to the regional reference nodes in most cases has not driven network augmentation Neither has there been significant augmentation of interconnector capacity that might have necessitated significant intra-regional augmentation. As such the broad conclusion seems to be that the limited generation expansion that has occurred in the NEM over the last decade does not seem to explain the transmission capex outcomes in aggregate or for individual TNSPs.

Ownership

The discussion to this point seems to suggest that endogenous factors (those factors within the control of TNSP management or their owners) play a larger part in explaining the relative differences amongst the TNSPs, than exogenous factors. In our report "*Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors*" we concluded that differences in ownership, and consequential impacts for investments incentives and regulation explained a significant part of the difference in the performance of the Distribution Network Service Providers (DNSPs). To what extent does this conclusion also apply here?

SP Ausnet is privately owned while the other TNSPs (except Electranet) are owned by their respective jurisdictional governments. In this sense, the differences in performance of the government-owned Powerlink, TransGrid and Transend compared to the privately-owned SP Ausnet agrees with the government/private performance differences that are observed in distribution networks.

However, in many respects the performance of Electranet, which is nominally privately owned, is comparable to the government-owned NSPs, rather than to SP Ausnet. This seems to undermine the conclusion that ownership is an explanatory factor for performance differences across the sector.

However, closer inspection suggests that Electranet may not be appropriately classified as a privately owned TNSP. Electranet's ownership is split between Powerlink (41% shareholding), YTL (a Malaysian infrastructure investment company) (33% shareholding) and two Australian superannuation funds (sharing the remaining 26%). Powerlink, which is wholly owned by the Queensland Government, acquired its share in Electranet in around 2001. It is the largest single shareholder in Electranet. Electranet's nine person Board is chaired by the previous Chief Executive of Powerlink. Three of the remaining eight Electranet Board members are employees of Powerlink including Powerlink's current Chief Executive Officer, its Chief Operating Officer and its Chief Financial Officer. Although Electranet is nominally a private company, Powerlink's part ownership role, and the presence of Powerlink's most senior past and present executives on its Board of Directors, calls into question whether Electranet is actually subject to the same incentives and disciplines that might be associated with a conventional, privately owned utility.

If Electranet is, de facto, to be classified as a government-owned NSP, then it would appear that government/private ownership differentiation of TNSPs as an explanation for comparative performance, conforms to the conclusions in our report *Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors* in relation to the impact of ownership on the outcomes delivered by DNSPs.

Planning

A second major area of differentiation between Victoria and the other TNSPs is in respect of the institutional arrangements and methodologies for network planning. AEMO is responsible for planning the augmentation of the Victorian transmission network, while planning is integrated with asset ownership for the other TNSPs. AEMO (and VENCorp before it) uses a different planning methodology – a cost/ benefit assessment – while other TNSPs use "deterministic" approaches, that do not systematically evaluate benefits against costs in planning augmentations to the network.

There have been many debates amongst market participants, network service providers, regulators and market operators on the merits of the different planning methodologies and different institutional arrangements for network planning in the NEM. The empirical assessment of outcomes over the last 10 years, as shown in this paper, suggests that the Victorian arrangements have delivered considerably better outcomes for energy users. This is most clearly observable in the evidence that demand growth has not been over-estimated in Victoria to the same extent that appears to be the case in NSW and QLD. We concluded that this forecasting error has contributed to the explanation for higher network augmentation expenditure per unit of actual demand in NSW and QLD than in VIC.

END NOTES

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[i] To be precise, SP Ausnet is not a Transmission Network Service Provider as this term is defined in the National Electricity Rules. The Australian Energy Market Operator (and before it VENCorp) is the TNSP in Victoria. AEMO plans the augmentation of the transmission network in Victoria and procures for its expansion. In this paper, the figures for revenues and expenditure for SP Ausnet

[ii] For example at a meeting of the AEMC's Transmission Frameworks Review Consultative Committee on 27 January 2011 Peter McIntyre, CEO of TransGrid, suggested that Victoria has many more 500 kV circuits than in New South Wales and that this endowment explained the lower augmentation expenditure in Victoria.

[iii] To be precise, SP Ausnet is not a Transmission Network Service Provider as this term is defined in the National Electricity Rules. The Australian Energy Market Operator (and before it VENCorp) is the TNSP in Victoria. AEMO plans the augmentation of the transmission network in Victoria and procures for its expansion. In this paper, the figures for revenues and expenditure for SP Ausnet also include the opex, capex and revenues determined by the AER for VENcorp.

[iv] Source: AER regulatory decisions

[v] Source: AER regulatory decisions, AEMO figures on energy and demand, as published in "National Electricity Forecasting Report, 2012"

[vi] Source: AER regulatory decisions, AEMO figures on energy and demand, as published in "National Electricity Forecasting Report, 2012". CME Analysis

[vii] Source: AER regulatory decisions, actual opex for historic data used where data available.

[viii] Source: AER regulatory decisions, actual opex for historic data used where data available, AEMO figures on energy and demand, as published in "National Electricity Forecasting Report, 2012".

[ix] Source: AER regulatory decisions, actual RAB for historic data used where data available. Note that transmission augmentations procured by VENCorp are not reflected in SP Ausnet's RAB. As such, a comparison of the transmission RAB in Victoria with the transmission RAB elsewhere also needs to account for the portion of the cost of augmentations procured by Vencorp (and now AEMO) which has not yet been recovered through regulated charges. These are not known with certainty (a VENCorp/AEMO "RAB") is not published by the AER. However on the basis of actual and allowed augmentation capex (in the first and second, and third regulatory control periods respectively), we would expect that adding around $300m to SP Ausnet's RAB in 2014 would account for the outstanding unrecovered cost of transmission assets produced by VENCorp/AEMO.

[x] Source: AER regulatory decisions, actual RAB for historic data used where data available, AEMO figures on energy and demand, as published in "National Electricity Forecasting Report, 2012".

[xi] AEMO's 50% probability of exceedance forecast of peak demand in 2013 is used.

[xii] Tasmania is not shown in this chart because its RAB has risen significantly while its peak demand has been declining, and the result distorts the comparison of the other NSPs.

[xiii] Source: AER regulatory decisions, AEMO figures on energy and demand, as published in "National Electricity Forecasting Report, 2012". CME Analysis

[xiv] Source: AER regulatory decisions, AEMO figures on energy and demand, as published in "National Electricity Forecasting Report, 2012". CME Analysis

[xv] Source: TNSP revenue proposal documents

[xvi] Source: TNSP revenue proposal documents

[xvii] Source: TNSP revenue proposal documents, AEMO figures on energy and demand, as published in "National Electricity Forecasting Report, 2012". CME Analysis.

[xviii] Source: TNSP revenue proposal documents

[xix] References

[xx] For example at a meeting of the AEMC's Transmission Frameworks Review Consultative Committee on 27 January 2011 Peter McIntyre, CEO of TransGrid, suggested that Victoria has many more 500 kV circuits than in New South Wales and that this explained the relatively better performance in Victoria.

Submission to the AER on Electranet Revenue Draft Determination 2013/14 to 2017/18

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The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission.

EXECUTIVE SUMMARY

This document is the EUAA's submission to the AER in relation to the AER's determination of the regulated revenues for Electranet over the period 2013/14 to 2017/18.

Our members have significant electrical demand in South Australia. Transmission charges, whilst not the largest element in their bills, does matter to them. Our members have had to suffer very large price increases in South Australia over the last decade. ElectraNet's revised revenue proposal would result in prices increasing about 5% above 2011/12 levels, by 2017/18.[1] For the reasons set out in this submission we do not support Electranet's proposal (or their revised proposal) for higher expenditure.

The AER's Draft Decision will result in average transmission prices increasing from $21.04 per megawatt hour (MWh) in 2013/14 to $23.31 /MWh in 2017/18 (in 2012$), an increase of 11 percent over the 5 year regulatory period[2]. However, prices decrease in the first year of the regulatory period from $24.35 / MWh in 2012/13 to $21.04/MWh in 2013/14, so that over the full period from 2012/13 to 2017/18 prices are expected to reduce slightly in real terms. Actual price changes will depend on demand – the AER set allowed revenues and hence lower demand will result in high prices (in order to recover the regulated revenue).

While we agree with the direction of the AER's Draft Decision we believe the AER should go further than it has in order to deliver a decision that meets the long term interests of energy users.

Our assessment is that Electranet's performance in terms of the level of operating expenditure, non-load capital expenditure and load driven capital expenditure compares unfavourably with that of its peers. Electranet also seems to have a long track record of forecasting demand to be significantly higher than it has actually turned out to be. Indeed the level of error in 2012 seems to be around 50%. This is a substantial error and suggests that, assuming Electranet built its network to meet its demand projections this would have resulted in significantly greater capacity than is needed.

Indeed, this is reflected Electranet's regulated asset base, per MWh transported, which is higher than that of all transmission network service providers in the NEM. Prima facie, therefore, we question the need for continued significant capital expenditure as Electranet has proposed. Some specific comments we have in relation to the AER's Draft Decision on capex are as follows:

[1] Based on AEMO's low energy growth forecast from the 2012 Electricity Statement of Opportunities (ESOO).

[2] Based on AEMO's low energy growth forecast from the 2012 Electricity Statement of Opportunities (ESOO).

- We do not think the argument that there is an asymmetric risk to under-forecast capex is valid. The system of revenue cap regulation provides Electranet with strong incentives to over-estimate its expenditure. Accordingly we can see no merit in allowances for conjectured asymmetric under-estimation risks.

- The AER's consultants expressed considerable doubt about the need for, or accuracy of, the expenditure on SA Water's replacement assets. This is a substantial proportion of Electranet's capex and so we suggest it be treated as a contingent project so that proper consideration can be given to the need for this project.

- We do not think Electranet's case for substantially higher expenditure on easements can be justified, taking account of expected negligible demand growth, and Electranet's track record of actual expenditure on easements during the current regulatory period.

On Electranet's opex, our analysis shows that Electranet also compares unfavourably with its peers in terms of opex per MWh transported, and the trend of substantially higher opex growth. Our specific comments on the AER's Draft Decision in this area is as follows:

- We do not believe that escalation of opex to reflect an increase in the value of the RAB can be sustained. It is reasonable, we think, to suggest that opex might rise if the network expands, but RAB changes are not a suitable proxy for network expansion.

- We agree with the AER that the base year for its calculation of opex 2011/12 (as proposed by Electranet) is not appropriate. But similarly we are not necessarily convinced that 2010/11 is better. We suggest the use of an average based on the audited data on opex during the previous regulatory period.

- We agree with the direction of the AER's thinking on condition-assessment opex. However we suggest that off-setting reductions (savings) should equal at least the level of the additional expenditure.

Finally, on service standard incentives, we note that Electranet could achieve additional revenues more than $35m over the coming regulatory period under the market impact incentive. We think this is excessive not least because the incentive does not even represent the economic costs of transmission connection to energy users (or indeed to wholesale market participants). We have therefore recommending adjusting the incentive to correct for this.

Table of Contents

1. INTRODUCTION **7**

2. ELECTRANET'S SUBMISSION IN CONTEXT **8**

2.1. SOUTH AUSTRALIAN ELECTRICITY PRICES 8
2.2. TRANSMISSION NETWORK SERVICES PRICES 9
2.3. PEAK AND AVERAGE DEMAND 10
2.4. OPEX 11
2.5. CAPEX 12

3. COMMENT ON DEMAND FORECASTS **14**

4. COMMENT ON ALLOWANCES FOR OPEX **16**

5. COMMENTS ON ALLOWANCE FOR CAPEX **18**

6. COMMENT ON COST OF CAPITAL **23**

7. COMMENT ON SERVICE STANDARDS INCENTIVES **24**

LIST OF FIGURES

Figure 1. Demand-weighted average spot prices in the NEM ($/MWh) 8

Figure 2 Average price of transmission services in the NEM (2012$ per MWh) 9

Figure 3. Trend rate of decline in average demand 2007 to 2012 10

Figure 4. Trend rate of growth/decline in annual peak NEM demand 2007 to 2012 11

Figure 5. Opex per MWh of transmission network service providers in the NEM..................11

Figure 6. Opex compound annual growth rate since 2005 12

Figure 7. Growth in the RAB per MWh transported..13

Figure 8. Electranet demand: actuals to 2012 and forecasts to 2018....................................14

Figure 9. Electranet opex: actuals, proposals and draft decision..16

Figure 10. Actual, proposed and Draft Decision capex...18

Figure 11. Average non-load driven capex divided by average energy..................................22

Figure 12. WACC in AER decisions compared to that of other regulators..............................23

1. Introduction

This document is the EUAA's submission to the AER in relation to the AER's determination of the regulated revenues for Electranet over the period 2013/14 to 2017/18.

Our members have significant electrical demand in South Australia. Transmission charges, whilst not the largest element in their bills, does matter to them. Our members have had to suffer very large price increases in South Australia over the last decade. We therefore do not support Electranet's proposal (or their revised proposal) for higher expenditure, which would result in price rises if not for the reductions in the allowed return as a result of lower risk free rates.

While we agree with the direction of the AER's Draft Decision we believe the AER should go further than it has in order to deliver a decision that meets the long term interests of energy users.

In preparing this submission, we have had regard to Electranet's proposal, the AER's Draft Decision and Electranet's revised proposal. Section 2 of this submission provides some context to Electranet's proposals and the AER's Draft Decision by examining end-user and transmission prices and NEM demand in South Australia. It also compares Electranet's actual and proposed opex and capex to that of its peers. The sections that follow set out our comments on demand forecasts, opex, capex, cost of capital and service standards incentives.

2. Electranet's submission in context

The AER's Draft Decision will result in average transmission prices increasing from $21.04 per megawatt hour (MWh) in 2013/14 to $23.31 /MWh in 2017/18 (in 2012$), an increase of 11 percent over the 5 year regulatory period[3]. However, prices decrease in the first year of the regulatory period from $24.35 / MWh in 2012/13 to $21.04/MWh in 2013/14, so that over the full period from 2012/13 to 2017/18 prices will reduce in real terms. By contrast ElectraNet's revised revenue proposal would result in prices increasing about 5% above 2011/12 levels, by 2017/18.[4] Actual price changes will depend on demand – the AER set allowed revenues and hence lower demand will result in high prices (in order to recover the regulated revenue).

2.1. South Australian electricity prices

South Australia's household electricity prices are on average the highest in the NEM, and even before the 18% increase from 1 July 2012, were the third highest on average in comparison to 91 other developed countries and regions of the world[5]. Comparative international data on business and industrial users' prices is not available.

This is a very bad outcome. Wholesale prices in the NEM in South Australia have played a part. As shown in Figure 1, the demand-weighted average spot price in South Australia has been higher than in other NEM regions particularly over the period 2008 to 2010, due to the exercise of market power by AGL at its Torrens Island Power Station[6] although there has been much greater spot price convergence since 2011.

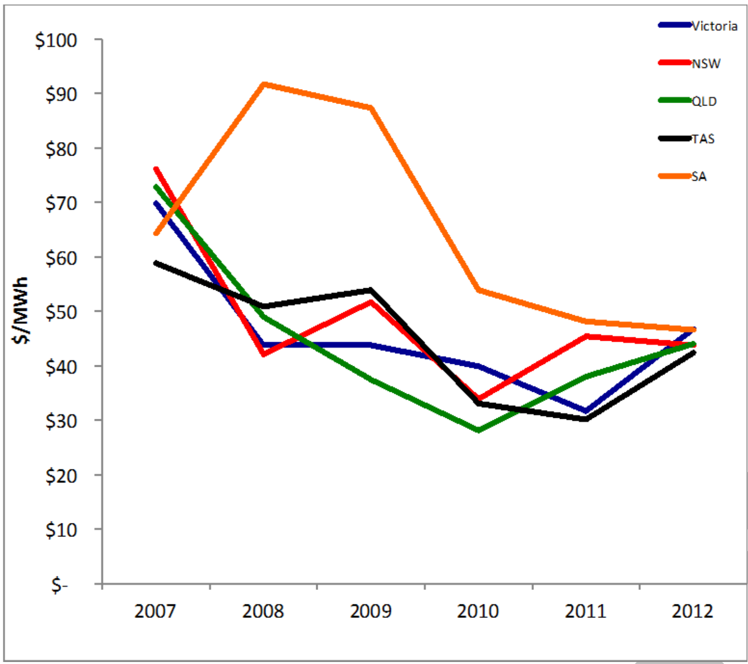
Figure 1. Demand-weighted average spot prices in the NEM ($/MWh)

[3] Based on AEMO's low energy growth forecast from the 2012 Electricity Statement of Opportunities (ESOO).

[4] Based on AEMO's low energy growth forecast from the 2012 Electricity Statement of Opportunities (ESOO).

[5] Mountain, B. 2012. *Electricity Prices in Australia: An International Comparison*. A report to the Energy Users Association of Australia.

[6] Mountain, B. 2012. *Market Power in South Australia.* A report to the Energy Users Association of Australia.



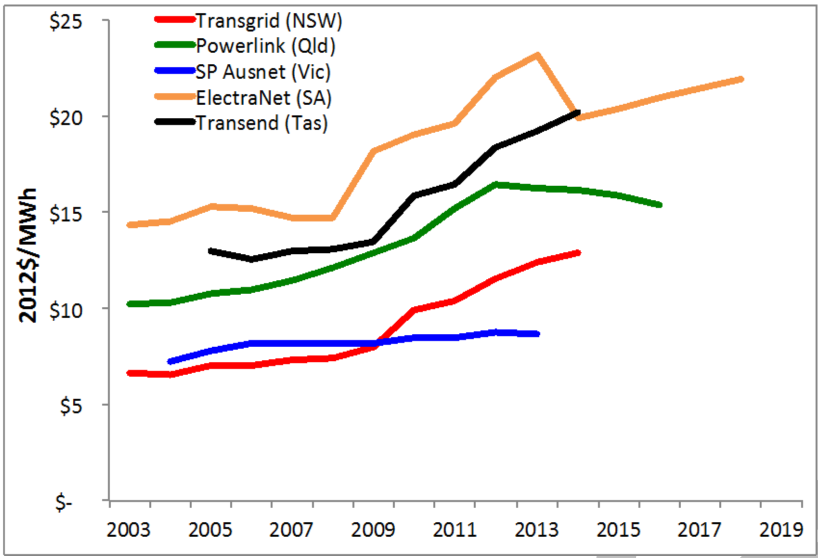
Source: EUAA analysis using metered demand data from NEMReview.

However the biggest factor in end users price rises in South Australia has been the price rise of network service providers, both Networks South Australia and Electranet.

2.2. Transmission network services prices

Electranet has made a contribution to South Australia's unwelcome distinction as the highest price region in the NEM. In 2012 it had the highest price of transmission services per MWh transported of all network service providers in the NEM. The AER's draft decision will reduce the gap in 2013, before prices rise again as shown in Figure 2. The most significant reason for the drop in prices in 2013 is however a reduction in the risk free rate – a factor over which the AER has no control.

Figure 2 Average price of transmission services in the NEM (2012$ per MWh)

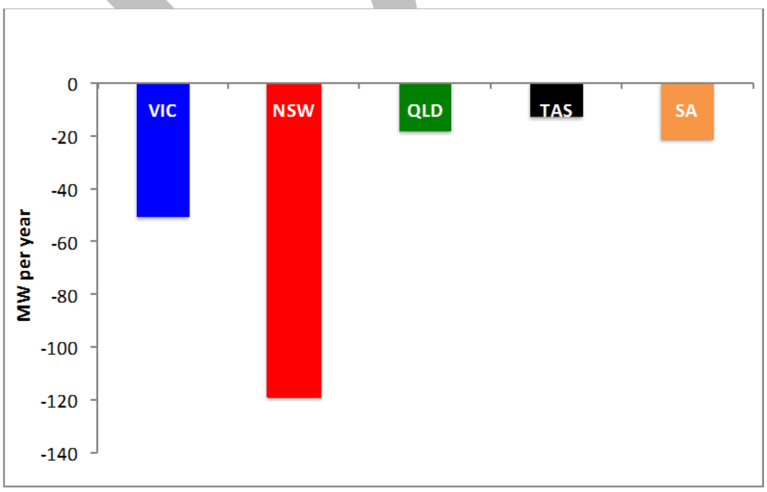


Source: EUAA analysis of AER and ACCC regulatory determinations

2.3. Peak and average demand

What is the broad context to Electranet's application? Electranet provides two services. It collects electrical current from grid-connected generators and delivers it to distributors and a small handful of end users that are connected to the high voltage transmission system. It also designs and operates a transmission system that is needed to meet the expected peak demand. So, how has the average and peak demand changed? Figure 3 shows the trend rates[7] of decline in average demand from 2007 to 2012. In South Australia over this period, average demand has declined by around 20 MW year-on-year. As a proportion of the annual average demand in South Australia this is the most rapid rate of decline of all NEM regions.

Figure 3. Trend rate of decline in average demand 2007 to 2012

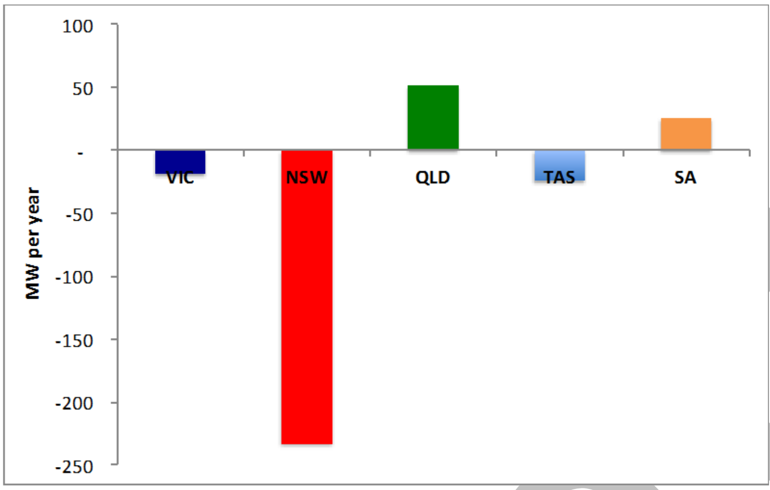


[7] The gradient of the linear regression of annual data.

Source: EUAA analysis using metered demand data from NEMReview.

Figure 4 shows the trend rate of growth/decline in annual peak (NEM) demand over the period from 2007 to 2012. It shows that as a trend rate, peak demand has risen in South Australia by 25 MW per year.

Figure 4. Trend rate of growth/decline in annual peak NEM demand 2007 to 2012



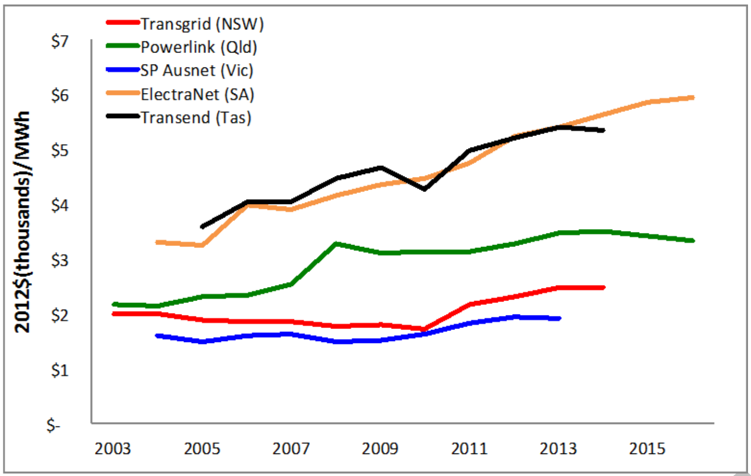
Source: EUAA analysis using metered demand data from NEMReview.

The observations to draw from these data is that over the last six years the demand for the services provided by Electranet, is at best declining slowly (average demand) or growing slowly (peak demand).

2.4. Opex

How does the level of opex and its growth by Electranet compare to its peers in the NEM? Figure 5 shows the latest available data on actual opex, and regulatory allowances where actual data is not available for all TNSPs operating in the NEM. It shows that per MWh transported, Electranet has the highest level of operating expenditure of all the TNSPs in the NEM. The data on opex for Electranet from 2013 is the AER's draft decision and shows that the gap between Electranet has grown wider relative to Powerlink and also relative to the other TNSPs unless the AER approves substantial increases in the level of their expenditure in future.

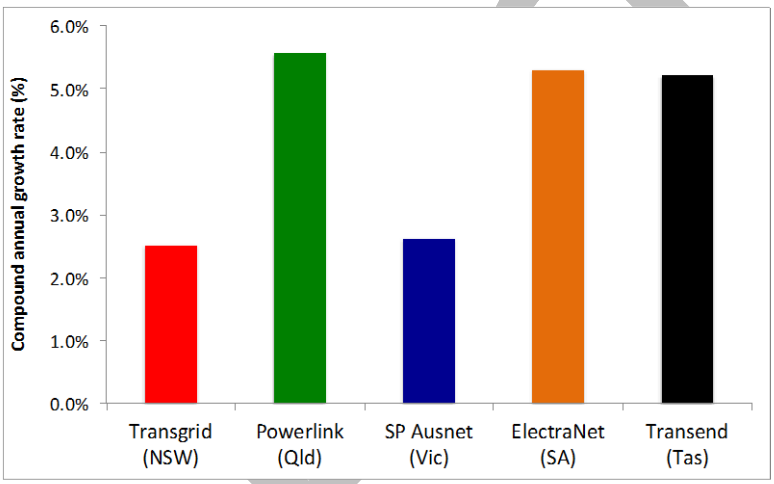
Figure 5. Opex per MWh of transmission network service providers in the NEM



Source: EUAA analysis of AER and ACCC regulatory determinations

Figure 6 shows the compound annual growth rate in opex since 2005 of TNSPs in the NEM, using the same data as show in Figure 6. It shows that as a compound annual growth rate, based on the AER's decision Electranet will have increased opex by a little over 5% per year, only a little bit slower than Powerlink.

Figure 6. Opex compound annual growth rate since 2005[8]



Source: EUAA analysis of AER and ACCC regulatory determinations

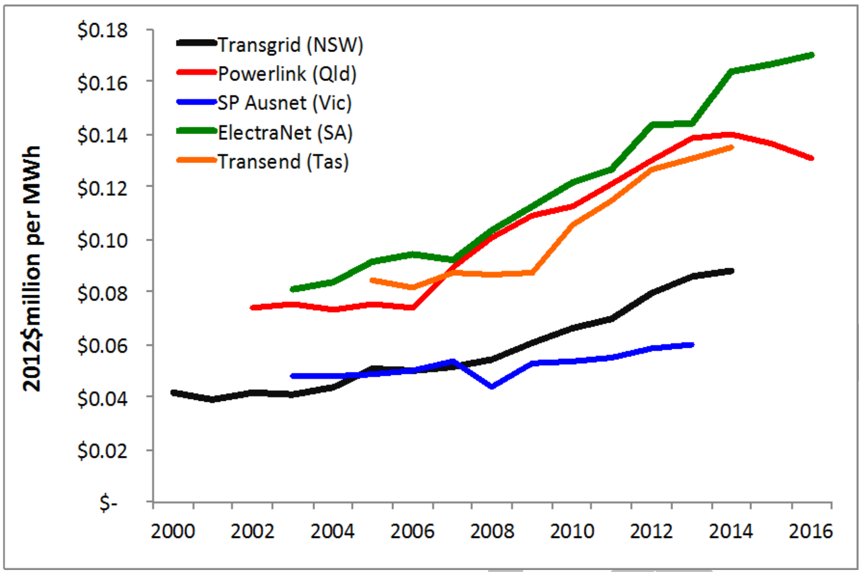
2.5. Capex

Capital expenditure results in an expansion of the regulated asset base (RAB). Figure 7 shows the change in RAB per MWh transported in the NEM, and uses the projection of Electranet's RAB based on the AER's Draft Decision. It shows that Electranet has a RAB that has grown

[8] Calculation in constant 2012$. Takes account of most recent data on actual opex, or regulatory allowances where actual data not available. Data for TransGrid and Transend to 2014, SP Ausnet to 2015, Powerlink to 2016 and Electranet (using AER's Draft Decision) to 2018.

around 2.5 times from 2003 to 2018. It already has a significantly larger asset base per MWh than any of the other TNSPs, and unless the AER allows significantly greater expenditure for other NSPs, Electranet's RAB per MWh transported will continue to be the highest in the NEM.

Figure 7. Growth in the RAB per MWh transported

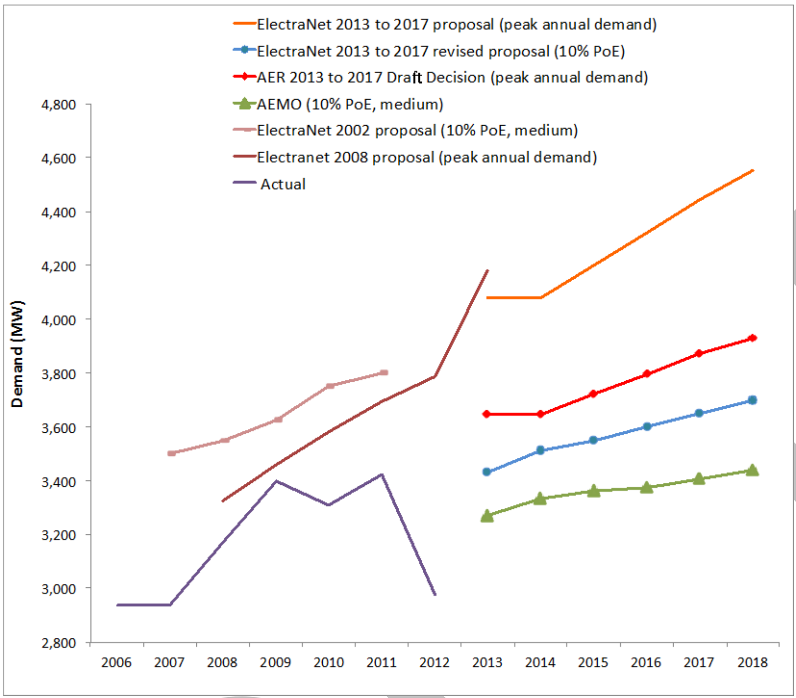


Source: EUAA analysis of AER and ACCC regulatory determinations

3. Comment on demand forecasts

We have examined the demand forecast that Electranet has made, and compared it to the AER's Draft Decision, and previous forecasts that Electranet has produced. The results are shown in Figure 8 below.

Figure 8. Electranet demand: actuals to 2012 and forecasts to 2018



Source: EUAA analysis of AER and ACCC regulatory determinations and network service provider proposals

Figure 8 shows that Electranet's initial 2013 to 2017 proposal was essentially a continuation of the rapid demand growth projections that it made in its previous two revenue control periods. Electranet's revised demand projections were significantly lower (800-900 MW) than their initial proposal, although the two projections are not directly comparable since the former is a projection of peak demand, while the latter is a projection of demand that has a 10% probability of exceedence.

These comparisons show that Electranet seems to have had a long history of projecting demand to be significantly higher than it has turned out to be. The error (difference between forecast and actual demand) in 2012 was about 1,700 MW i.e. projected peak demand was about 50% higher than actual peak demand in 2012. The error in 2013 is yet to be known, but may well prove to be significantly higher than this.

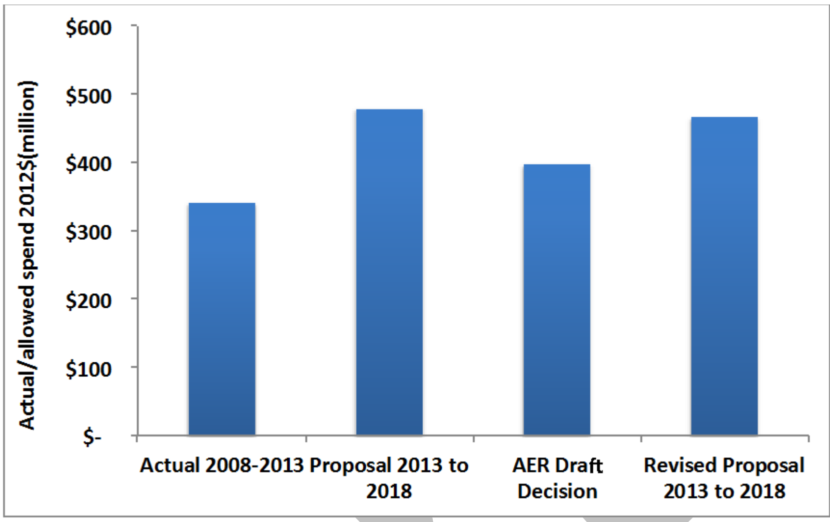
Electranet's revised proposal demand forecast is significantly lower, but still substantially above – for all years of the regulatory control period - the level of actual peak demand.

We accept that it is difficult to relate demand projections to capital expenditure. Our main concern is that, as we noted earlier, as a trend rate, peak demand has grown by around 25 MW per year in South Australia. Electranet has historically forecast much higher rates of demand growth and presuming it believed its forecasts, will have the augmented capacity of its network accordingly. This therefore suggests that there is significant spare capacity on the Electranet network. We would have expected that this would have resulted in significantly lower capital expenditure in future whereas this is not the case based on Electranet's proposal and the AER's Draft Decision. We take this point in more detail in our discussion on capex.

4. Comment on allowances for Opex

We noted in Section 2 that Electranet's opex per MWh transported is the highest in the NEM. To some degree this may be explained by scale economies – a relatively large network in South Australia in comparison to the volume of energy through-put. However, Electranet's opex has also grown very strongly relative to other TNSPs. This, along with declining average demand is resulting in higher operational charges per MWh delivered. Against this context, Electranet has sought a significant expansion in opex, and although their revised proposal is lower than their initial proposal, the gap is small. This is summarised in Figure 9 below.

Figure 9. Electranet opex: actuals, proposals and draft decision



Source: EUAA analysis of AER and ACCC regulatory determinations

We support many aspects of the AER's Draft Decision on opex, although there are few issues that we suggest might be revised.

Opex escalation based on the change in the RAB

We do not think that opex should be escalated based on RAB escalation. Electranet has proposed relatively low expenditure on network augmentation and relatively much more asset replacement. During the regulatory period, the RAB will therefore be expanding as a result mainly of asset replacements. In general new assets will have a lower maintenance and operational expenditure requirement than the old assets that they replace. This should therefore result in a decrease in the allowance for opex, not an increase.

To the extent that any allowance is to be made for increased opex as a result of increased network capacity, we suggest that the AER develops on index that accounts for changes in network length and transformation capacity.

Condition assessment opex

We support the AER's approach to the substantial increase in opex to account for expenditure that Electranet has proposed, to improve its field maintenance / condition assessment systems. Electranet has not taken account of the savings that such higher expenditure will deliver, rather it has alluded to savings arising, possibly, in future regulatory periods.

We suggest this is unrealistic. If our members sought approval for such large increases in their operating costs, they can be expected to have to justify it by demonstrating savings that exceed the cost of the investment. Electranet has not done this. Noting again, the evidence of comparatively high operating costs and sustained increases to-date, we can not support further substantial increases in the absence of off-setting savings of at least the level of the increase attributable to the investment in field maintenance / condition assessment systems.

Opex efficiency factors

The AER has decided a 2.5% efficiency adjustment to the trend of Electranet's historic expenditure. We note that Electranet is "deeply concerned" about this. In its revised proposal it suggests that such adjustments are contrary to the incentive regime that the AER is required to implement. We disagree with Electranet's response. The issue here is what level of efficiency improvement should be expected as a matter of course, and what should be expected to be result from above-average effort. The AER's 2.5% adjustment is, we consider, too low. After inflation, expected at 2.5%, Electranet's real opex will essentially remain constant. By comparison, across the Australian economy real productivity improvements of 1-2% can be expected as a matter of course, with significantly greater improvements expected and achieved in various industries for long periods. In other words, just to keep up with the base level of productivity improvement across the economy, the AER's opex efficiency factor should be in the range of 3.5% to 4.5%, not 2.5%.

We suggest that opex efficiency improvements greater than a reasonable expectation of the economy-wide improvement in productivity should be reflected in the AER's opex efficiency factor. The incentive scheme operated by the AER should only reward Electranet for improvements beyond a reasonable base level. Accordingly we propose that the AER increase its opex efficiency factor from 3.5% to 4.5%.

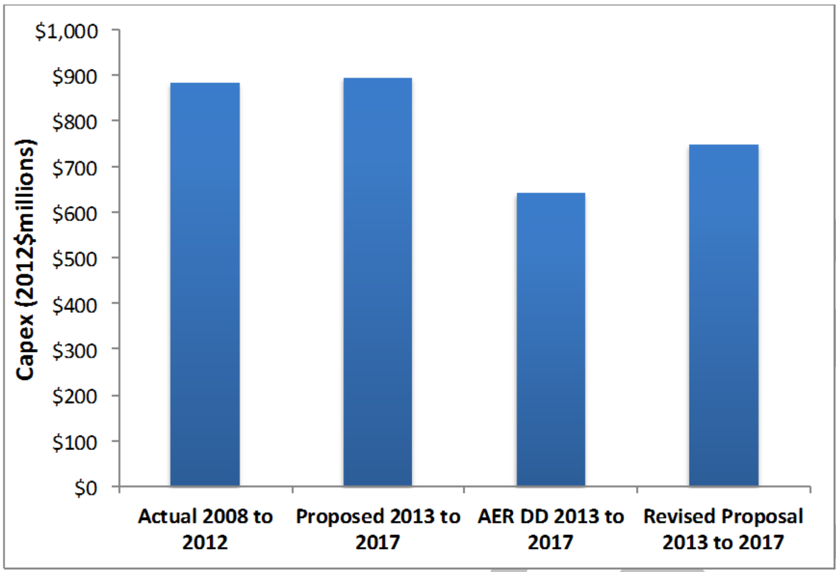
Choice of base year

We agree with the AER that Electranet's proposed base year 2011-12 is not appropriate. However, we are not convinced that 2010/11 is necessarily the right answer either. We suggest that the AER averages the opex for all years in the current regulatory period for which audited actual data is available, in setting the base year for the opex allowance for the next control period. Electranet's annual opex seems to exhibit some significant inter-annual variance and the choice of an average of the outcome in the regulatory period would seem to be an appropriate way to deal with this uncertainty.

5. Comments on allowance for capex

Electranet's total actual opex compared to its proposal, revised proposal and the AER's Draft Decision is set out in Figure 10.

Figure 10. Actual, proposed and Draft Decision capex



Source: EUAA analysis of Electranet proposals and AER Draft Decision

In the rest of this section we set out some of our comments on the proposals and the Draft Decision.

Cost estimation risk factors

We disagree with the AER's allowance for any upward adjustment to take account of what Electranet calls "cost estimation risk". Electranet's arguments on this is based on a report by Evans and Peck, to the effect that there is an asymmetric risk (outturn costs are more likely to be higher than lower). The Evans and Peck analysis is just an assertion – there is no reliable evidence that project costs, as defined at a particular point and after taking account of changes in specification, changes in project scope and so on are likely to turn out to be asymmetrically higher rather than lower.

On the other hand, the regulatory control provides Electranet very powerful incentives to over-inflate their expenditure projections in their proposals to the AER. To the extent to which they are able to convince the AER to allow higher expenditure than they need, they benefit from this financially. This is a very real incentive and is likely to more than neutralise any possibility that outturn costs will be higher rather than lower.

Accordingly we cannot support the AER's decision to make an allowance for "cost estimation" risk.

SA Water replacement assets

ElectraNet has proposed $398 million for replacement capex up from $237.4 million during the current period (an increase of 68% from the current period). The AER draft decision provides $261 million, an increase of 10.2% from ElectraNet's expenditure in the current period. Approximately 31% (or $123.4 million) of the total replacement capex comes from the replacement of substations supplying electricity to SA Water's pumping stations .

The AER has included the full amount of the upgrade into ElectraNet's proposed replacement capex despite some serious concerns expressed by its consultants.

EMCa expressed concern that only a high level concept planning and cost estimation had been implemented and that the documentation provided by ElectraNet did not have condition assessment reports supporting ElectraNet's beliefs (EMCa report p. 95). EMCa also stated that they had concerns over the "reasonableness of the expenditure in the timeframe and the lack of justification, including options and risk assessment, relevant to the level of the proposed expenditure." (p. 95). They also had issues with the age profile of some of ElectraNet's assets, EMCa stated that overall the age profile of the substations assets was relatively young, despite the existence of older transformers (p. 112).

EMCa could not conclude that the pumping station replacement capex represented efficient costs and the AER should not accept those costs as part of the capex proposal without a justified business case (p. 96). The National Electricity Rules (NER 6A.6.7(c)) state that the AER cannot accept costs that are inefficient.

Given the concerns expressed by its consultants, we suggest that the AER should not accept the $124 million replacement of the substations and the AER should review its draft decision accordingly.

Concerns about the arrangements for prescribed transmission services

Under the current arrangements if a user of the transmission system or group of users request changes to the services for infrastructure that provides prescribed transmission services they would be required to pay for the upgrade. If SA Water had requested a change in service that required the substations to be upgraded then it would incur the cost of the replacement of the substations.

ElectraNet argued that the plant and equipment at the substations were at the end of their technical and economic life and need to be replaced, subsequently the AER sent a letter to SA Water requesting further information and SA Water stated that they had not requested a change in service i.e. they have not requested an upgrade and had no plans to increase the pumping requirements for the pumping stations (SA Water letter from Peter Seltzikis to Warwick Anderson at the AER dated 12 October 2012).

The EUAA shares the concerns expressed by EMCa that the current arrangements for prescribed transmission services are flawed. EMCa state that:

> *The current arrangement for grandfathering and prescribed transmission services disincentivises SA Water from notifying ElectraNet from any change in the services (i.e. pumping stations) that SA Water may require as the current grandfathering arrangements would fall away requiring require SA Water to pay the full cost of change in services.* (p. 96).

EMCa point out that:

> *'Replacement of assets on a like for like basis assumes that the required service for water pumping will not have changes for 100 years (55 years to date plus 45 years future). It is considered that the required service will not have changed over this time. This does not appear to be a reasonable assumption given the development of water dependent consumers in the region.'*

The EUAA is also concerned that there is nothing preventing SA water requesting a service upgrade after the installation of the new substations as it would only be required to pay for any upgrades related to the change in service required by the customer (i.e. avoiding a cost of $123.4 million for a potentially lower cost). We also suspect that SA Water could receive additional benefits from the substation replacement as technology in substations has likely improved from when they were first installed.

We concur with EMCa that the current arrangements need to be reviewed as they have the potential to push costs for changes in services requested by certain customers onto others who will not derive any benefit.

The AER has said it is bound by the Rules and has agreed that this Rule should be reviewed. We agree with the AER and in view of the doubt expressed by the AER's consultants, about this substantial expenditure, we call on the AER not to make any allowance for this capital expenditure in its Draft Decision, but rather to identify this expenditure as a Contingent Project so that it can be reviewed in greater detail during the regulatory period. In the mean time we call on the AER to propose a change to the rules on this issue, as a matter of priority.

Easements

We support the AER's Draft Decision on easements. We note that Electranet has reduced its easement claim in its revised proposal, but we remain unconvinced that the budget that Electranet has sought is reasonable.

In this regard we note that in its last determination, Electranet had applied to spend around $20m on easements in the first three years of the current regulatory period, whereas its records show it has spent just $2.7m. In its submission Electranet has projected that it has spent/ will spend another $27m between 2011 and 2013. We do not find this convincing given their track record of a significant difference between what they have claimed and what they have actually done.

Again, in the context of a network whose demand is growing very slowly, if it all, we fail to see how Electranet's substantial easement expenditure can be justified.

Load driven capex

Electranet's load driven capital expenditure proposal has reduced by $100m to $216m in their revised proposal compared to from $316m in their initial proposal. This compares to a reduction in their demand between their initial and revised proposal of about 700 MW. In their revised submission they suggest that load driven capex has reduced by $113m due to their lower revised demand projection. This implies avoided costs of $0.11million per MW.

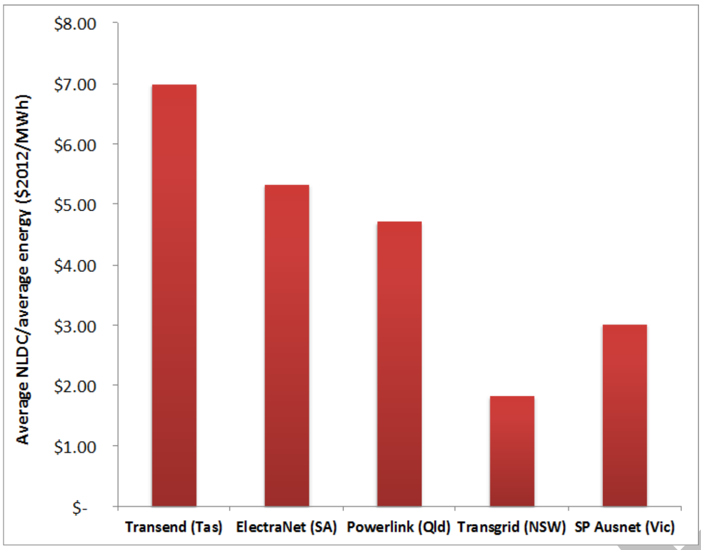
This begs the question: if Electranet's revised proposal was an increase in demand of 700 MW, would they have only sought an additional $100m to meet that demand, or would they have sought substantially more? CME analysed this marginal cost in their report "A comparison of outcomes delivered by electricity transmission network service providers in the National Electricity Market" which is available on our website and was released last year. This found a marginal cost of load driven expenditure of around $0.85m per MW of demand growth, roughly 8 times higher than Electranet has suggested by comparing their initial and revised proposals.

The AER's load driven capex reflects the AER's demand forecasts, which are higher than Electranet's revised forecasts. We call on the AER to revisit this load driven capex allowance to take account of the lower demand forecasts and also the apparent disparity between the marginal avoided cost of lower demand forecasts and the higher marginal additional cost associated with higher demand forecasts.

Non-load driven capex comparisons

Electranet's average non-load driven capex – from 2005 and up to the end of the 2012/13 regulatory period, compared to its peers in shown in Figure 10 below. It shows that Electranet compares poorly to its peers, being the second-highest compared to Transend.

Figure 11. Average non-load driven capex divided by average energy



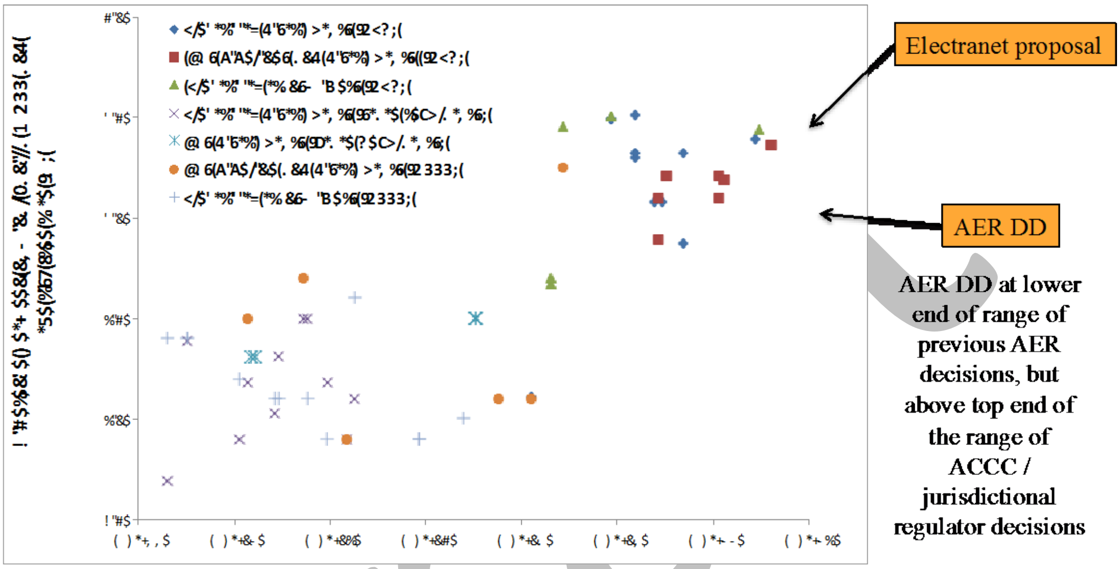
The AER's Draft Decision is to allow Electranet even more non-load driven capex over the coming regulatory period, than it has spent over the previous periods. To the extent that non-load driven capex of its peers does not rise to the same extent, Electranet's non-load driven capex would therefore be even less competitive.

We therefore fully support the AER's reduction of Electranet's non-load driven capex to account for the increase in the opex allowance that Electranet has sought for its condition assessment systems. We question however, why a saving *greater* than the cost is not reflected in the AER's assessment.

6. Comment on cost of capital

The AER's Draft Decision has resulted in a cost of capital that is comparable to the level it has set in recent decisions[9], although at the lower end of the range of these decisions, as shown in Figure 12.

Figure 12. WACC in AER decisions compared to that of other regulators



We reluctantly support the AER's Draft Decision. With regard to the debt risk premium we note the AER's concern about the extrapolation of the Bloomberg fair value curve, and the Australian Competition Tribunal's recommendation to complete a public consultation process before considering any alternative methods.

As the AER is well aware the EUAA has been critical of the calculation of the debt risk premium in particular. This criticism is now well accepted in the industry. Energy users are continuing to pay a price for this, and the EUAA looks forward to a speedy resolution of this in the development of the AER's cost of capital guidelines.

[9] The comparison is of vanilla WACC less the risk free rate.

7. Comment on service standards incentives

We support the AER's decision on all aspects of the service standard incentive with the exception of the market impact measure. With the market impact incentive, Electranet can earn an additional $34.5m over the regulatory period. To earn this, it simply needs to ensure that the cumulative number of dispatch values who marginal network value exceeds $10/MWh is less than the five year average. We suggest that this is a poorly designed incentive. Marginal value of network constraints ignore the volume of redispatch that might have arisen as a result of the congestion. It is the volume of the redispatch cost, not just a marginal price of 5-minute congestion that matters. The AER's incentive creates a significant risk that Electranet will charge consumers far more than the economic cost of the constraint (or the market value of the constraint to buyers and sellers in the NEM). We appreciate there is no scope to redesign the scheme now, but we suggest as an interim measure that either:

- the percentage of MAR at stake in the market impact measure be reduced from 2% to 0.2%; or
- the incentive sets a much tougher target before additional revenue is awarded. This could be for example by setting a target number of dispatch intervals at a quarter or a third of the current level.