REVIEW

Australian Energy Market Commission

ADVICE TO SCER

Consideration of Differences in Actual Compared to Forecast Demand in Network Regulation

26 April 2013

Reference: EPR0035

Advice to SCER

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About the AEMC

The Council of Australian Governments (COAG), through its then Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. In June 2011, COAG established the Standing Council on Energy and Resources (SCER) to replace the MCE. The AEMC has two principal functions. We make and amend the national electricity, gas and energy retail rules, and we conduct independent reviews of the energy markets for the SCER.

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Executive Summary

The Standing Council on Energy and Resources (SCER) has requested the Australian Energy Market Commission (AEMC) to provide advice on the implications of differences between actual and forecast demand within the operation of the economic regulatory frameworks applied to electricity network service providers (NSPs).

In the request for advice SCER noted that recent observations on demand suggest that there may be a sustained slowing of the growth in peak demand and a decline in average demand. SCER has requested the AEMC to provide advice on:

- whether any changes to the current National Electricity Rules (NER) are needed to ensure consumers receive the benefits of sustained reductions in demand; and
- how should the Australian Energy Regulator (AER) consider differences in demand when undertaking regulatory determinations.

There are a number of aspects of demand forecasts that influence the need for network capital expenditure (capex) including forecasts of peak demand, average demand and demand from new customer connections. Demand forecasts are not only important for expenditure decisions at the overall network level, but also at a more local level within each network where demand patterns may be different to the overall network demand trend. Recovery of network revenues will also be influenced by changes in demand within particular customer tariff classes. As a consequence, trends in overall system demand does not have a simple direct relationship with network expenditure and prices faced by consumers.

Following the recently made network regulation rule changes, the AEMC does not recommend further changes to the NER. The incentive based regulatory regime is now sufficiently flexible to allow the AER to put financial measures in place that encourage NSPs to adjust their capital programs in response to variations between actual and forecast demand within the regulatory control period. These adjustments will be reflected in prices during the subsequent regulatory control period. How consumer prices are affected during the current regulatory control period depends on whether the control mechanism is a revenue cap or a weighted average price cap (WAPC), which are the two most common forms of control mechanisms applied to NSPs.

Control mechanism and risk allocation

Under a revenue cap, consumers bear the risk of variations between actual and forecast demand within the regulatory control period. This is because the NSP is allowed to recover up to the revenue the AER allows irrespective of the actual level of demand. Any shortfall in revenue or excess revenue recovered by the NSP as a result of actual demand being different from forecast will be passed through to consumers and reflected in the following year's prices. Hence network prices will increase during the current regulatory control period when actual demand is *less* than forecast demand. Conversely, the network prices would fall when actual demand is *greater* than forecast in the previous year.

By contrast, under a WAPC form of control, NSPs face the risk of actual demand being different from forecast demand. This is because the NSP is subject to a maximum allowed average price rather than a maximum allowed revenue. This means that consumers face an average network price which is fixed over the regulatory control period.

Under a WAPC form of control, NSPs will earn higher revenues if actual demand in any year is *greater* than forecast. Conversely, network revenues would fall if actual demand is *less* than forecast. For consumers, the average network price is fixed for the current regulatory control period.

A revenue cap weakens the link between a NSP's revenue and actual demand. The NSP does not benefit from increasing volumes and hence reduces any disincentive for the NSP to promote demand side participation activities.

Current application of control mechanisms

The NER requires the use of revenue caps for all transmission network service providers (TNSPs). For distribution network service providers (DNSPs) the AER has the option, subject to considering relevant criteria, to apply control mechanisms from a range that includes a revenue cap, a price cap, a WAPC or an average revenue yield that controls the revenue on a per customer basis. In its recent decisions on the control mechanism, the AER has explicitly considered the different impact of these control mechanisms on volume risk and revenue recovery, incentives for demand management and price flexibility and stability.

DNSPs in New South Wales, Victoria and South Australia are under a WAPC control while Queensland and Tasmania are under a revenue cap. The Australian Capital Territory DNSP is the only business under an average revenue yield control mechanism. The AER has recently proposed to move the DNSPs in New South Wales onto revenue caps in their next regulatory determination commencing in 2014-15.

We consider that the AER should retain the option to consider the best control mechanism at the time of each revenue determination. This allows the AER to consider factors such as the predictability of demand when deciding the control mechanism and the risk sharing between consumers and NSPs. Therefore, we advise that the NER should continue to provide the AER with the option to determine the form of control mechanism to apply to DNSPs. As TNSPs charges are generally recovered by DNSPs on their behalf, the potential benefits of a WAPC control mechanism for TNSPs are more limited. Therefore, we do not consider it appropriate to change the use of revenue caps for TNSPs.

Incentive to over or under forecast demand

Capex to augment the capacity of the network relies heavily on peak demand forecasts, and is a large part of the capex programs in the current regulatory control period of NSPs. As a percentage of total capex, demand related capex is around 25 per cent for distribution networks, but much larger, at around 60 per cent, for transmission networks.

If demand growth is higher than the forecasts reflected in the regulatory determination, the NSP may need to incur additional capex. Likewise, expenditure might be set too high if actual demand turns out to be less than forecast demand.

All NSPs can have an incentive to over-forecast peak demand in their regulatory proposals as a means to protect them from the risk of incurring additional capex to meet higher demand than forecast. For NSPs under a WAPC control mechanism, there is also an incentive for them to under-forecast consumer numbers and average demand. This is because these values are used in setting the allowed prices over the regulatory control period.

Historical evidence on differences between NSPs' forecast and actual demand does not suggest clear evidence of a tendency to under or over forecast. This appears to be because there are a range of different factors, including those provided by the regulatory arrangements, reliability obligations and shareholder governance, which affect the forecasting incentives of NSPs.

Enhanced by the recent changes made in the *Economic Regulation of Network Service Providers* rule change, the AER has the capacity and powers under the NER to assess the NSPs forecasts and substitute its own forecasts where appropriate.

Reasoning

After our assessment of the current arrangements and views expressed by stakeholders in our consultation process, we are not recommending any new changes to the NER. A summary of our reasons is set out below.

Importance of network tariff structures

NSPs under a WAPC control mechanism can try to offset the risk to their revenues through decreasing their expenditure or changing their tariffs. However, there are the barriers to efficient pricing, and the AEMC has made recommendations in the *Power of Choice* review to address these barriers.

Without appropriate arrangements for efficient pricing there is a risk that some NSPs under a WAPC control mechanism will change their tariff structures in an attempt to pass on more of the demand risks onto consumers. This could be through changing their tariffs in a manner which either:

- recovers a greater proportion of revenue from consumers with higher demand growth than the average consumer, or
- through increasing its proportion of revenue to be recovered from charges not dependent upon volumes.

Such changes to tariff structures can disadvantage certain types of consumers as it affects the distribution of costs across the consumer base.

The adoption of the recommendations from the AEMC's *Power of Choice* review would provide increased guidance on setting efficient network pricing structures. It would also expand the determination process to also include consideration of and consultation on NSP's proposed tariff structures and increase the AER's role in the annual network tariff setting process.

These changes would also give the AER greater opportunity to take a holistic consideration of its decisions in relation to allowed revenues including its decision on the level of the rate of return, the choice between revenue caps and WAPC plus approval of network tariffs.

New framework for capex incentives

Following last year's amendments under the *Economic Regulation of Network Service Providers* rule change, the AER has a range of tools to incentivise NSPs to adapt their capex programs to changes in demand occurring during the regulatory control period.

In particular, the NER provides the AER with the ability to develop a capital incentive expenditure scheme. The AER is currently in the process of developing details of this scheme and released an Issues Paper in March 2013. Under the AER's proposal, NSPs would have a strong incentive not to spend any more capex than is necessary at any time during the regulatory determination and irrespective of whether the NSP's actual capex is higher or lower than the forecast reflected in the AER's determination. This is because the AER is proposing that NSPs would keep between 20 and 30 per cent of any capex it does not spend below the forecast reflected in the AER's determination and would bear 40 per cent of any capex above the forecast reflected in the AER's determination. To be fully effective these strong incentives will need to be reflected by shareholders in the incentives placed on the management of NSPs.

Assessment of alternative approaches

A number of stakeholders have proposed approaches that they consider could strengthen the link between incentives for efficient expenditure and changes in demand during the regulatory control period. These approaches attempt to reduce the time lag between approval of expenditure within revenue determinations and the timing of expenditure, or apply a reconciliation adjustment to prices to account for differences between forecasts and actual demand.

Following the network regulation rule changes the NER provides the AER with the ability to introduce a range of different incentive mechanisms of the type proposed by stakeholders. Therefore, introducing such new approaches into the NER is not required. Furthermore, changing the regulatory frameworks for revenue determinations again following significant changes made in 2012 may undermine investor certainty.

The proposed approaches that cannot be implemented by the AER under the NER involve a substantial expansion in the use of the contingent project mechanism or periodic reviews of whether assets installed previously remain economically useful.

Increasing the use of the contingent project mechanism would substantially increase the number of projects that the AER was approving on a 'project by project' basis rather than the AER setting an overall revenue for the NSP. Such approaches would not be consistent with incentive based regulation. They would undermine the accountability of the NSP for delivering a reliable supply. It would also reduce the incentives to minimise the costs of delivering each project.

Approaches that involve an increase in the use of contingent projects or a reconciliation based on differences between forecast and actual demand are also dependent upon being able to segment out the proportion of capex which is solely driven by forecast demand. This in part assumes there are no synergies for decision-making between demand driven capex and other capex and opex. We understand that many network investments are undertaken in response to several drivers such as replacement of assets and the need to meet reliability standards, which need not all be related directly to demand. It is common for NSPs to align the timing of replacement programs with demand augmentation projects.

The AEMC has previously considered a rule change request by the Major Energy Users group to allow the AER to do an ex post optimisation of NSPs asset base to reflect any underutilised assets. We did not make a rule because we considered that any benefits from removing underutilised assets from the asset base would be outweighed by additional costs faced by consumers because investors in the NSPs would require a higher rate of return to recognise the increased risk of not recovering the costs of previous investments.

Use of demand forecasts in investment planning

The requirement in the NER to apply the relevant regulatory investment test (ie the RIT-T or RIT-D) means proposed network investments are assessed and subject to public consultation, based on the most recent forecasts of future demand available at the time the test is applied. This is a public accountability mechanism that shows whether NSPs are using the most up-to-date information when making investment decisions part way through regulatory control periods.

The AEMC's reviews into distribution and transmission reliability standards could also address the need for reliability requirements to remain appropriate in light of changing demand.

Relationship between demand forecasts and network revenues

While capex driven by demand related growth (ie augmentation and customer connections growth) is a substantial proportion of an NSP's capital outlays, it has only a relatively small effect on network revenues in the regulatory control period. For example, demand related capex accounted for only around 6 per cent - 10 per cent of distribution network revenues over the current regulatory control periods.

A large proportion of capital outlays is related to asset replacement and customer connections (for DNSPs), rather than to meet increases in peak demand. Going forward, if there is a significant growth in demand side participation and energy efficiency, the proportion of capex for demand driven augmentation could decline.

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1 Introduction

1.1 Scope of request for advice

The Standing Council on Energy and Resources (SCER) has requested the Australian Energy Market Commission (AEMC or Commission) to provide advice on the implications of differences between actual and forecast demand within the operation of the economic regulatory frameworks applied to electricity network service providers (NSPs).

Broadly, SCER has requested the AEMC to:

- investigate the implications of differences between actual and forecast demand within the operation of the economic regulatory frameworks applied to NSPs;
- provide advice on the merits of the AER considering differences between actual and forecast demand when undertaking network determinations in an incentive-based regulatory environment;
- assess how the risks associated with such differences are shared between the NSPs and consumers under the current regulatory frameworks;
- assess how the costs of managing such risks affect consumers and NSPs' incentives; and
- provide advice on whether any changes to the current National Electricity Rules (NER) are needed to ensure consumers receive the benefits of sustained reductions in demand, including but not limited to the AER's ability to consider previously approved capital expenditure (capex) and improvements to the NER around annual network tariff setting.

The Request for Advice states 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 as set out in the National Electricity Law.

This review covers both the electricity transmission and distribution networks sectors.

While the accuracy of peak and system demand forecasts are important, this issue and the process the AER employs in making demand forecast for network determinations are out of scope of the AEMC's advice to SCER.

Relevant considerations

In preparing our advice, we have had regard to:

- the long term interest of consumers consistent with promoting the achievement of the National Electricity Objective;
- the revenue and pricing principles as set out in the National Electricity Law; and
- incentives for efficient investment provided in the existing NER.

We have also had regard to a number of other pieces of work which relate to the issues raised in this review, including:

- AEMC's *Economic Regulation of Network Service Providers* Rule Determination made on 29 November 2012.[1] This rule determination made amendments to Chapters 6 and 6A of the NER (and corresponding sections of the National Gas Rules) which relate to the economic regulation of network services. The amendments provide the AER with additional strength and flexibility in setting revenues and prices for electricity (and gas) service providers.
- AEMC's *Optimisation of Regulatory Asset Base and Use of Fully Depreciated Assets* Rule Determination made on 13 September 2012.[2] The AEMC did not make a rule. The AEMC considered that the solution proposed by the proponent created risks and could be effectively addressed as part of a broader set of capital expenditure incentive issues and solutions examined as part of the Economic Regulation of Network Service Providers rule change request.
- The AEMC's *Distribution Network Planning and Expansion Frameworks* Rule Determination made on 11 October 2012.[3] This rule determination introduced, amongst other things, the regulatory investment test for distribution (RIT-D) NSPs.
- AEMC's *Power of Choice review*.[4] This review made a series of recommendations aimed at the responsiveness of the demand side to evolving market, technological developments and changing consumer interests over the next 15 to 20 years. SCER agreed to a number of these recommendations at its 14 December 2012 meeting and is currently progressing its implementation.
- AEMC's reviews into *transmission and distribution reliability standards*. The AEMC is currently investigating how to develop a nationally consistent frameworks and methodology for developing, describing and reporting on electricity network reliability and associated standards in the National Electricity Market (NEM).
- AER's *Better Regulation Program.* The AER is making a series of guidelines to set out their approach to regulation under the amendments made in the *Economic Regulation of Network Service Providers* Rule Determination and is also establishing a Consumer Challenge Panel to provide an independent consumer perspective to challenge the AER and NSPs during determination processes.

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1 AEMC, *Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services*, Final Rule Determination, 29 November 2012.

2 AEMC, *Optimisation of Regulatory Asset Base and Use of Fully Depreciated Assets*, Final Rule Determination, 13 September 2012.

3 AEMC, *Distribution Network Planning and Expansion Framework*, Final Rule Determination, 11 October 2012.

4 AEMC, *Power of choice review - giving consumers options in the way they use electricity,* Final Report, 30 November 2012.

- Australian Energy Market Operator's (AEMO) *National Electricity Forecasting Report 2012*.[5] In this report, AEMO has for the first time, developed an independent set of electricity forecasts for each region of the NEM to capture and assess the notable changes in demand taking place.
- Productivity Commission's draft report on its inquiry into *Electricity Network Regulatory Frameworks*.[6] The Productivity Commission made a number of recommendations to strengthen the AER's ability to put in place strong incentives for NSPs to make efficient expenditure decisions.

Consultation with stakeholders

As required by the Request for Advice, the AEMC has consulted with a range of stakeholders in developing its advice. To give interested stakeholders appropriate opportunity to present their views on the questions, we held a stakeholder workshop on the 28 February 2013 and circulated a short discussion paper.

Following the workshop, we received nine submissions from stakeholders including NSPs, AEMO and consumer representative groups.[7]

1.2 Context to our advice

1.2.1 Peak demand and energy consumption trends

SCER noted in its Request for Advice recent observations on demand which suggest that, for the first time, there may be a sustained slowing of the growth in peak demand and an absolute decline in average demand.[8]

The long term trend of annual energy growth in the Eastern states appears to be decreasing, as shown in Figure 1.1, although there is a high degree of volatility between the years. Financial year 2002-03 saw the first 12 month period of negative growth in annual energy consumption, which was followed by negative growth years in 2004-05, 2007-08 and 2010-11.

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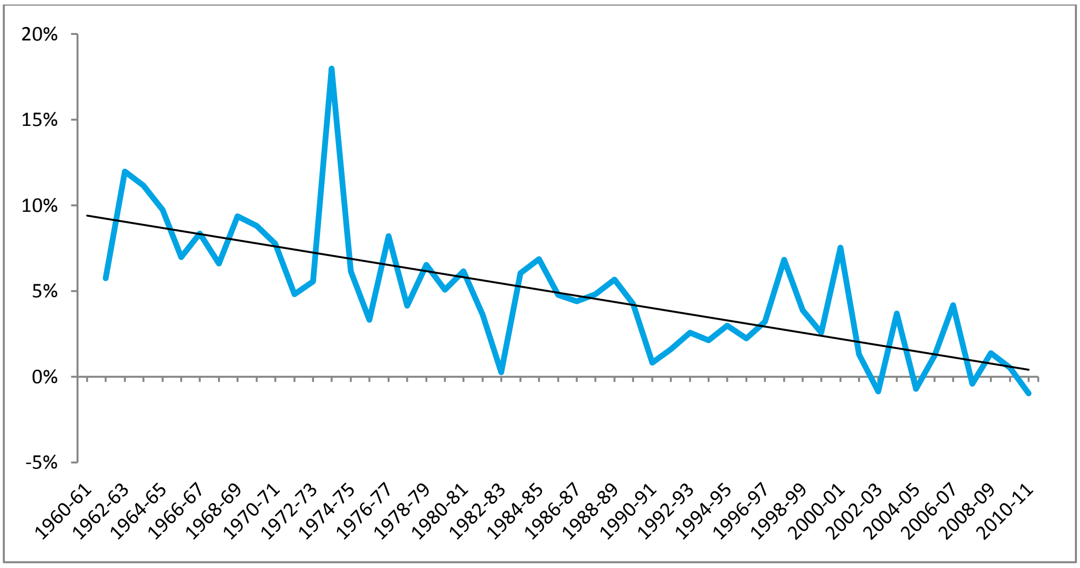
5 AEMO, *National Electricity Forecasting Report 2012*, 29 June 2012.

6 Productivity Commission, *Electricity Network Regulatory Frameworks*, Draft Report, 18 October 2012.

7 Details of the workshop discussion and presentations plus the stakeholders submissions are available on the AEMC website at: http://www.aemc.gov.au/Market-Reviews/Open/differences-between-actual-and-forecast-demand-in-network-regulation.html.

8 The growth rate of average demand has been slowing over many decades, so an absolute decline is a continuation of this longer term trend.

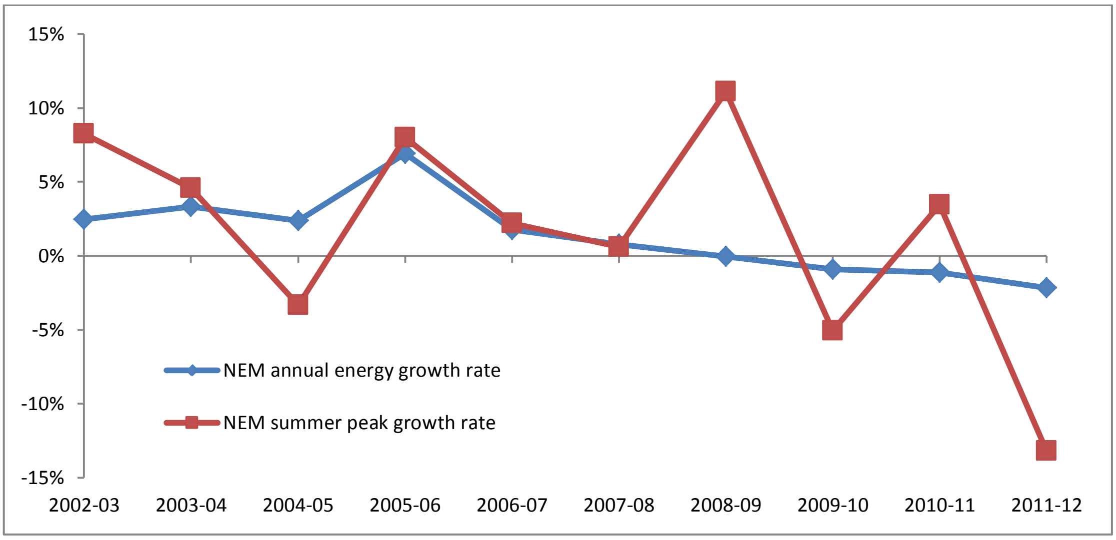
Figure 1.1 **Eastern states annual energy consumption growth rate 1960-61 to 2010-11 (with trend line)**[9]



Source: BREE 2012, Table I, AEMC analysis.

Consistent with the overall historical trend in the Eastern states, growth in annual energy consumption across the NEM has been consistently falling as shown in Figure 1.2. Summer peak demand has been more variable over the same period, with negative growth in 2009-10 and 2011-12.

Figure 1.2 **NEM annual energy consumption and summer peak demand growth rates 2002-03 to 2011-12**[10]



Source: AER performance of the energy market data, AEMC analysis.

Investment in transmission and distribution network infrastructure is primarily driven by local and regional economic factors. Appendix A provides an analysis of energy and peak demand forecasts for each region in the NEM.

9 Includes NEM and off-grid consumption.

10 Note that Tasmania joined the NEM in 2005. As a result, the annual energy growth rate for 2005-06 is inflated.

1.2.2 Use of demand forecasts in network determinations

There are a number of aspects of demand forecasts that influence the need for network capex including forecasts of peak demand, average demand and demand from new customer connections. Demand forecasts are not only important for expenditure decisions at the overall network level, but also at a more local level within each network where demand patterns may be different to the overall network. Recovery of network revenues will also be influenced by changes in demand within particular customer tariff classes. As a consequence, trends in overall system demand does not have a simple direct relationship with network capex and prices faced by consumers.

Comparing key drivers of particular sub-categories of capex is difficult as there is not strict definition of what constitutes network capex categories among NSPs.[11] There are generally three broad sub-categories of capex that contribute to overall network capex. These include growth capex, augmentation capex and replacement capex. In this Advice, unless stated otherwise:

- growth capex refers to new customer connection requests and upgrading of the network to facilitate new connection net of customer contributions;
- augmentation capex refers to capex needed to install or upgrade assets to increase network capacity in response to growth in peak demand; and
- replacement capex refers to capex required to replace ageing assets

It has been estimated by one stakeholder that augmentation capex as a percentage of total capex is around 26 per cent in the distribution sector, but much larger, at around 60 per cent, in transmission sector.[12] Growth capex appears to be significant part of distribution NSPs' capex programs and can be difficult to forecast. For example, in Victoria, forecast growth capex ranged from 14 per cent to 32 per cent of total capex across the DNSPs in the 2011-2015 regulatory determination.

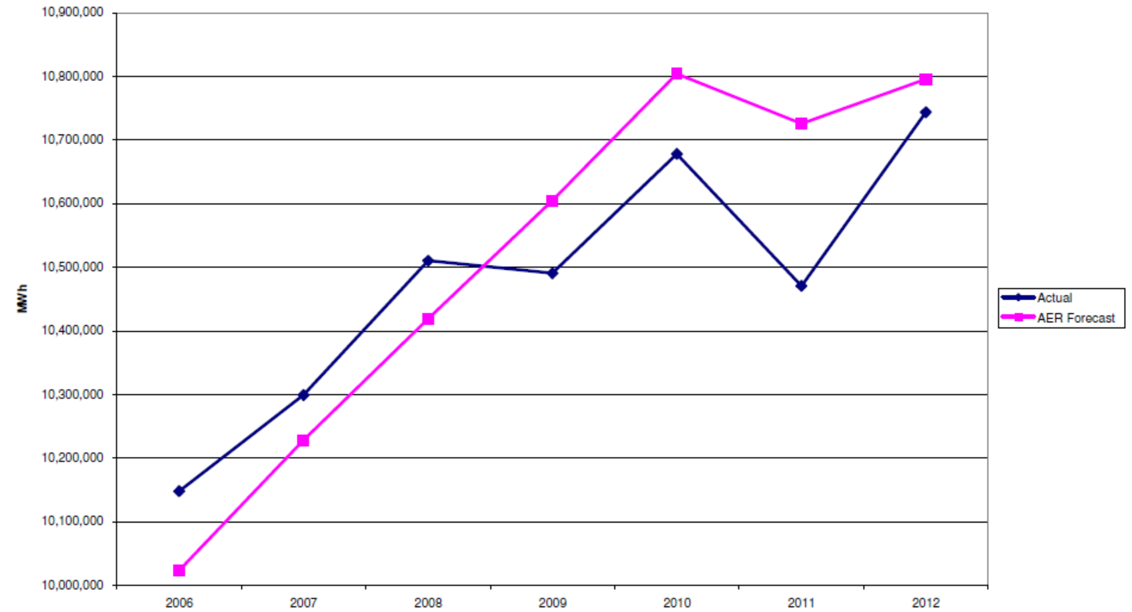
However, as a percentage of consumer retail prices, growth capex for DNSPs account for only around 4 per cent in Queensland to less than 1 per cent in Victoria. Inclusion of transmission related augmentation capex is unlikely to significantly increase this figure given the small proportion of retail prices attributed to transmission (less than 10 per cent) and the large proportion of TNSP revenue that is recovering the capital invested in previous expenditure.

There appear to be a range of factors that affect the incentives in NSPs to forecast demand levels, with some incentives encouraging higher forecasts and some lower forecasts. There have been a number of instances where the approved demand level has under-forecasted actual demand as shown Figures 1.3 and 1.4 below.

11 The AER is currently consulting on how best to categorise NSP proposed expenditures as part of its Better Regulation program of work.

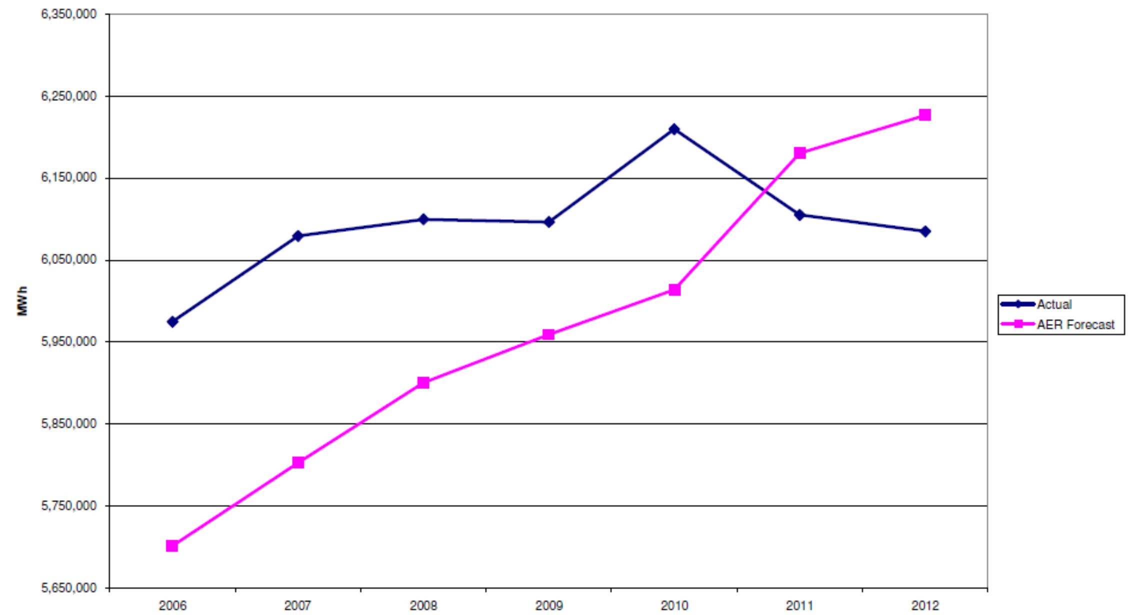
12 EUAA submission. p.2.

Figure 1.3 Actual demand versus AER forecast demand for CitiPower over 2006 to 2012



Source: CitiPower and Powercor submission, p.3.

Figure 1.4 Actual demand versus AER forecast demand for Powercor over 2006 to 2012



Source: CitiPower and Powercor submission, p.3.

1.3 Structure of our advice

This advice is structured as follows:

- **Chapter 2** assesses the impact of demand risk on consumers and NSPs from the choice of control mechanism applied to NSPs to recover its allowed revenues and evaluates whether any changes are warranted.
- **Chapter 3** sets out our assessment of the risks from changes in demand on the incentives for NSPs to undertake efficient network expenditure to reflect the changes in demand. It also sets out our evaluation of whether any changes are needed in the regulatory frameworks.

This advice also contains the following appendices that supplement our assessments and recommendations in chapters 2 and 3:

- **Appendix A** – examines the historical trends in average and peak demand, investigates the difference between forecast demand and actual trend and assesses the materiality of the link between changes in demand and consumer prices.
- **Appendix B** – provides a detailed explanation of how the current provisions in Chapters 6 and 6A of the NER deal with changes in demand.
- **Appendix C** – presents an assessment of four approaches that we have considered to further increase the link between link between differences in demand and NSPs allowed revenues.

2 Demand risk and control mechanism

Summary

- The choice of control mechanism determines how the risk of differences between forecast and actual demand impact consumers. The current NER requires the use of revenue caps for TNSPs while the AER has a choice in relation to DNSPs that range from a revenue cap to a WAPC.
- Under a revenue cap, consumers bear the risk of any divergence in actual demand from forecast demand within the current regulatory control period. The average network price for consumers will increase (or decrease) during the current regulatory control period under a revenue cap where actual demand is less than (or greater than) forecast demand.
- Under a WAPC, NSPs face the risk of actual demand being different from forecast demand. Where actual demand in any year is less than (or greater than) initially forecast, NSPs will earn less than (or greater than) the revenue estimated by the AER. For consumers, the average network price remains fixed during the current regulatory control period.
- The NER should continue to provide the AER with the choice to determine the form of control mechanism to apply to DNSPs. This will allow the AER to consider factors such as the predictability of demand when deciding the control mechanism and the risk sharing between consumers and DNSPs.
- As TNSPs charges are generally recovered by DNSPs on their behalf, the potential benefits of a WAPC control mechanism for TNSPs are more limited. Therefore the use of revenue caps for TNSPs remains appropriate.
- Overall, the current frameworks provides the AER with the ability to consider the risks and impacts on consumers and NSPs in relation to variations in demand – including rate of return, the control mechanism and the approval of tariff structures across a range of decisions to ensure that the long term interest of consumers are taken into account.
- The adoption of the recommendations from the AEMC's *Power of Choice* review can be expected to assist by expanding the regulatory determination process to also include explicit consideration of and consultation on NSP's proposed tariff structures for the forthcoming regulatory control period, and increasing the AER's role in the annual network tariff setting process. This will help ensure that the regulatory frameworks appropriately manage the risks in relation to differences between actual and forecast demand in the long term interest of consumers.

2.1 Control mechanisms under current frameworks

The NER currently requires TNSPs to be subject to a revenue cap control mechanism. In contrast, the NER allows the AER to determine the control mechanism to be applied to DNSPs from a range that includes a revenue cap, a price cap, a WAPC or some other alternative – having regard to criteria set out in the NER. The criteria include:

- the need for efficient tariff structures;
- effects on administrative costs;
- the regulatory arrangements in the prior regulatory control period; and
- the desirability for consistency between the regulatory arrangements for similar services.[13]

In the past, the AER has also considered the implied risk to revenue recovery, as well as the incentives for demand management, in making its decision on the appropriate control mechanism for DNSPs.

DNSPs in New South Wales, Victoria and South Australia are under a WAPC form of price cap while Queensland and Tasmania are under a revenue cap. The Australian Capital Territory DNSP is the only NSP under an average revenue yield form of control mechanism.

Table 2.1 Form of control mechanisms by jurisdiction

State	Control mechanism	
	Distribution	**Transmission**
ACT	Revenue Yield (average revenue cap)	Revenue Cap
NSW	WAPC – current. Revenue Cap proposed from start of the 2014 regulatory control period	Revenue Cap
QLD	Revenue Cap	Revenue Cap
SA	WAPC	Revenue Cap
TAS	Revenue Cap	Revenue Cap
VIC	WAPC	Revenue Cap

A revenue cap works by allowing network prices to change annually over the current regulatory control period in order recover the annual revenues determined for an NSP at the start of the current regulatory control period. Therefore an NSP under a revenue cap is guaranteed its revenue in the current regulatory control period.

A WAPC works by constraining changes in average annual network prices determined at the start of the current regulatory control period. Revenues of an NSP under a

13 NER clause 6.2.6.

WAPC can therefore fluctuate from year to year within its current regulatory control period.

An average revenue yield control works by placing a cap on the average revenue per unit of electricity sold in the current regulatory control period. An NSP on average revenue yield control can experience annual fluctuations in revenues earned as in the case of a WAPC.

The various control mechanisms permitted in the NER is discussed in more detail in Appendix B.

The AER has recently indicated that it proposes to move the DNSPs in New South Wales onto revenue caps in their next regulatory determination commencing in 2014-15.[14] The AER is concerned that the DNSPs in New South Wales have changed prices in a way that has not promoted more efficient pricing structures.[15]

2.2 Impact of control mechanisms

The AER uses forecasts of demand levels in determining the efficient amount of expenditure, and then converts that into a either a revenue cap or WAPC for the business. This forward looking assessment will reflect assumptions about expected future demand levels both at a network and local level plus customer connections.

The choice between revenue and WAPCs determines how the risk of differences between forecast and actual demand impact consumers and NSPs within the current regulatory control period. The impacts are summarised in Table 2.2.

14 AER, *Stage 1 Framework and approach paper - Ausgrid, Endeavour Energy and Essential Energy*, March 2013.

15 Id., p.10.

Table 2.2 Demand risk impacts under different control mechanisms

Demand risk under revenue cap control mechanism		
	Impact on NSPs	**Impact on Consumers**
Actual Demand higher than forecast	Revenues are fixed. Profits are lower if additional capex is required	Average price decreases to reflect additional revenue earned from higher demand
Actual Demand lower than forecast	Revenues are fixed. Profits are higher if capex is deferred	Average price increases to reflect loss of revenue caused by lower demand
Demand risk under WAPC control mechanism		
	Impact on NSPs	**Impact on Consumers**
Actual Demand higher than forecast	Additional revenue earned increases as volume sales exceeds forecast. Impact on profit depends upon tariff structure	Average price remains unchanged although tariff rebalancing may occur.
Actual Demand lower than forecast	Lower revenue earned as volume sales are lower than forecast. Impact on profit depends upon tariff structure	Average price remains unchanged although tariff rebalancing may occur

2.2.1 Revenue cap

Under a revenue cap, the NSP will earn the same amount of revenue during the current regulatory control period regardless of whether demand is higher or lower than that forecast at the time of the regulatory determination. This is because the tariffs proposed by the NSPs in each year of the regulatory control period will only be approved where demand forecasts at the time the tariffs are being assessed mean that the expected revenue is less than or equal to the revenue cap.

The actual revenue recovered by the NSP during the year will depend on actual demand, which may be more or less than forecast demand. However, the NSP's maximum allowable revenue in future years will be adjusted for any difference between the expected and actual revenue of previous years using an "unders" and "overs" account.

The demand risk arising from any changes in forecast demand is therefore borne by consumers rather than the NSP. As a result, revenue caps do not undermine an NSP's incentives to undertake demand management since it not exposed to any revenue risk from changes in demand.

2.2.2 Weighted average price cap

A WAPC exposes NSPs to a greater degree of risk where demand differs from forecast. NSPs have an incentive to propose conservative (low) demand volumes at the time of the determination. The lower the assumed volumes, the higher are the tariffs required in order to result in the same expected tariff revenue, and therefore the lower the price path over the regulatory control period.

Under a WAPC, the actual revenue received by the NSP will depend on the actual quantities it sells at each tariff component, and there is no later adjustment to account for revenues being above or below the revenue expected at the time of the regulatory determination. If actual demand turns out to be higher than forecast, the NSP will receive more revenue and if demand is less than expected, the NSP will receive less revenue. However the impact on the NSP's profits will depend on the extent to which its costs also change with revenues as a consequence of higher/lower demand.

2.3 Consumer prices and NSP profitability

The control mechanism adopted for price changes during a regulatory control period affects the volume risk and subsequent profitability risk faced by NSPs and consumers, where actual demand outcomes during the period differ from forecast demand.

Figure 2.1 below illustrates schematically the effects of differences between forecast demand and actual demand on average consumer prices as well as on NSP profits under a revenue cap or a WAPC. Figure 2.1 covers scenarios of actual demand being both lower and higher than forecast demand. It shows:

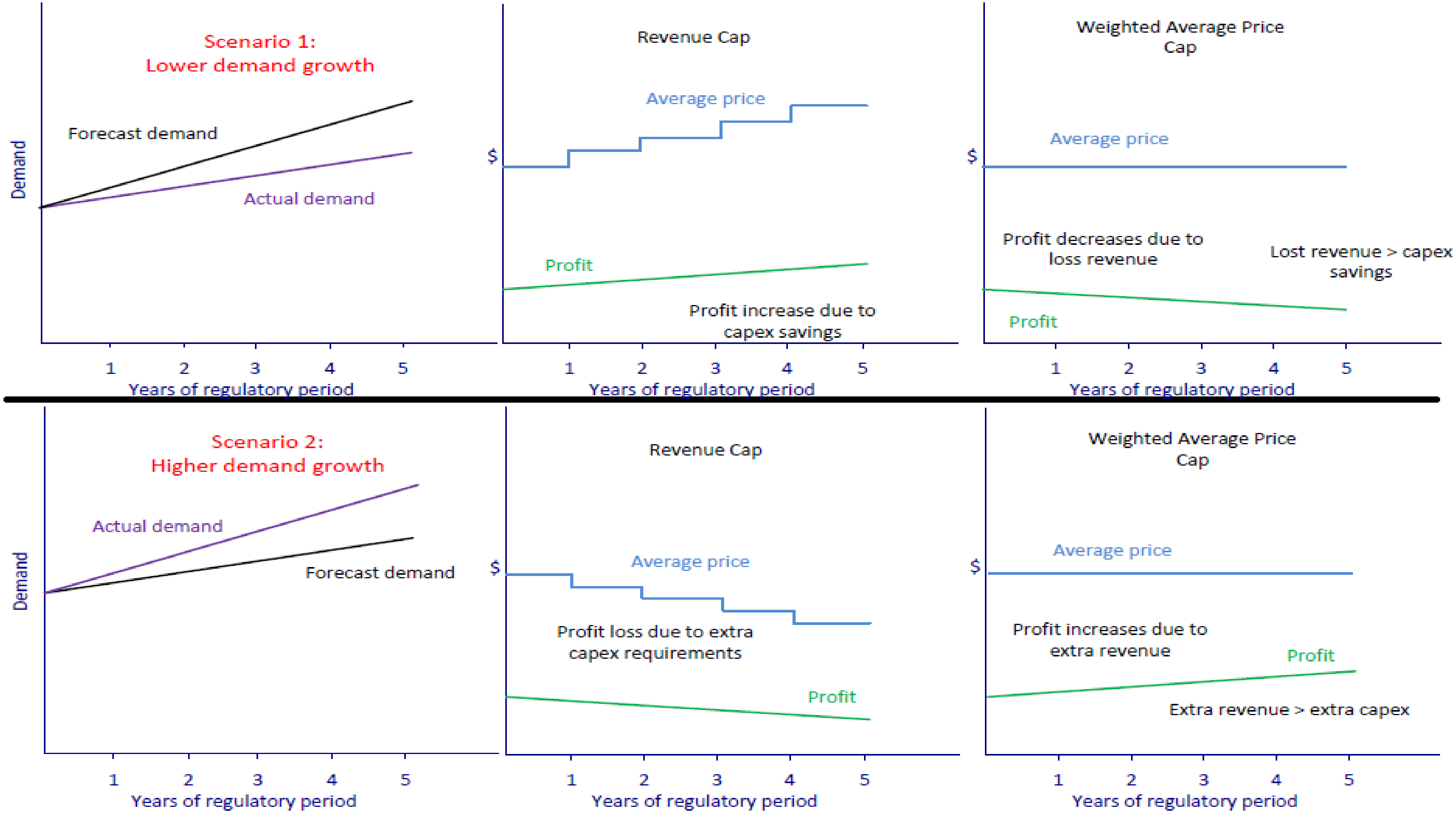
- In a scenario of lower demand than forecasted, a revenue cap protects a NSPs profit as the NSP is able to increase average prices to account for any loss of revenue caused by the lower demand. An NSP under a revenue cap would see its profit increase due to costs savings from falling demand. Under a WAPC, average price remains unchanged but the NSP profit falls.
- In the scenario where actual demand is higher than forecast, a revenue cap will result in average price falling while a WAPC will keep average prices constant. The NSPs profit is higher under the WAPC because it is able to earn more revenue due to the higher demand which should be more than any increase in costs caused by the higher demand, under current tariffs.

At the end of the five year period, prices are reset to account for actual demand.

For consumers as a whole, one advantage of a WAPC is that average network prices will not change if actual demand is different from forecast. As network costs can account for up to 50 per cent of retail prices, this can be a material benefit.

Appendix B provides a more comprehensive overview of how revenue caps and WAPCs work.

Figure 2.1 Impact on average consumer prices and network profit from differences in forecast and actual demand



2.4 Incentives for efficient tariff structures

Under a revenue cap, NSPs do not have an incentive to set efficient prices which reflect the underlying costs of supply, given that they receive the same, fixed amount of revenue over the regulatory control period irrespective of the prices they set.

A revenue cap may also provide incentives to adopt inefficient tariff structures where the NSP can increase its profits by increasing prices on tariffs of price-sensitive consumers in order to induce demand reduction. Reduced demand from price-sensitive consumers will mean that the NSP can make savings on its costs of supply to those consumers while still recovering its fixed revenue over the regulatory control period.

In contrast to revenue cap, under a WAPC the actual revenue earned by the NSP will depend on actual quantities sold under each tariff component. This means that the revenue earned by the NSP within the regulatory control period is affected by changes in demand such that where demand is greater than (or less than) initially forecast, NSPs will earn greater than (or less than) the revenues determined under the building block cost build-up. How this affects NSPs' profits will depend on the extent to which their tariffs are cost reflective.

Under a WAPC, if tariffs are not cost reflective (ie fixed and variable cost components are not proportionally recovered by fixed and variable charges), then changes in demand may result in over or under recovery of costs, and therefore changes in NSPs' profitability. Where a portion of fixed costs are being recovered by variable charges, the NSP will under recover its overall costs when demand falls. Under recovery occurs even when network investment falls concurrently with falling demand, as NSPs must still recover the fixed cost of the existing network.

An ongoing reduction in demand may lead NSPs to seek to modify non cost reflective tariff structures so that fixed costs continue to be recovered. This may be accomplished by rebalancing fixed and variable tariff components so that they accurately reflect the underlying breakdown between the NSP's fixed and variable costs.

In practice, the incentive for NSPs to adopt more cost reflective tariff structures may be offset by incentives to maximise revenues. This can be achieved by increasing tariffs the most on the fastest growing components of demand and limiting price increases on those elements where demand is falling. NSPs ability to rebalance tariff elements may also be affected by jurisdictional pricing requirements and the side constraints applying in the NER between individual tariffs.

At the stakeholder workshop, we presented two examples where NSPs have rebalanced their tariffs in light of changing demand patterns. The first example was Ausgrid's move in 2012-13 from a two tier volume based tariff structure to a three tier tariff structure.[16] The second example is the tariff rebalancing by Victorian DNSPs that resulted in substantial over-recovery of revenue during the 2006-10 regulatory control

16 See AEMC, *Possible future retail electricity price movements: 1 July 2012 to 30 June 2015*, Electricity Price Trends Report, 22 March 2013, pp. 44-46.

period. According to the AER, the Victorian DNSPs averaged a recovery of 8.28 per cent of revenue annually above forecast.[17]

A question that arises is whether it remains appropriate for networks to have the flexibility to rebalance tariffs in this way without proper consideration of the impacts on consumers of such rebalancing.

In the *Power of Choice* review, the AEMC made a number of recommendations that would improve the ability of NSPs to adopt efficient and flexible tariff strategies, and would improve the level of consultation and understanding associated with changes in tariff strategies, including where prompted by sustained reductions in demand. These proposed changes would directly address the issue of providing efficient tariff structures in the face of uncertain future demand levels, and include:

- changes to the pricing principles to provide better guidance for setting efficient and flexible network pricing structures;
- more robust consultation and verification applied to the annual network tariff setting process, including consulting on requested changes to the approved statement of network pricing structures.
- a new requirement for DNSPs to develop and consult with retailers and consumer groups on a statement of proposed network pricing structures as part of their regulatory proposals;
- possible changes to the network pricing side constraints; and
- a requirement for the AER to publish a guideline for network tariff arrangements.

2.5 Incentives for demand management

Incentives for NSPs to undertake demand management are also adversely affected by a WAPC form of control. However, the demand management and embedded generation connection incentive scheme is intended to counteract this incentive, by allowing prices to be adjusted to reflect foregone revenue.

As part of its *Power of Choice* review, the AEMC considered the incentives under the NER in relation to demand management in depth, and recommended that the NER be amended to reform the application of the demand management and embedded generation connection incentive scheme so that it:

- provides an appropriate return for demand side participation (DSP) projects that deliver a net cost saving to consumers; and
- better aligns network incentives with the objective of achieving efficient demand management.[18]

17 AER, *Framework and approach paper: Ausgrid, Endeavour Energy and Essential Energy - Regulatory control period commencing 1 July 2014*, Preliminary Positions, p. 128.

18 AEMC, *Final Report, Power of Choice Review*, 30 November 2012, p. 205.

The Commission's recommended changes to the demand management and embedded generation connection incentive scheme are intended to address concerns that the existing scheme does not adequately provide an incentive for distributors to explore and develop DSP options instead of capital investment.

2.6 Recommendations

2.6.1 Appropriateness of revenue cap for TNSPs

There do not appear to be any material reasons to change the use of revenue caps for TNSPs. As noted by Grid Australia in its submission, the relationship between transmissions charges and demand is weak and uncertain and the link between transmission augmentation requirements and demand is not uniform and constant.[19]

TNSPs do not have the same ability to react to changes in demand in terms of their investment decisions as DNSPs can. For example, larger capex projects such as substantial transmission line augmentations upgrades, that have long lead times cannot be re-scoped, deferred or discontinued economically once committed. Typically transmission capex is associated with more projects that are relatively high in value with longer planning and construction lead times compared to distribution capex projects.

In addition, since it is the DNSPs who pass on the transmission charges and determines the structure of network tariffs faced by consumers (other than very large directly connected customers), TNSPs would not be able to manage the demand risks from changes in volumes under a WAPC as well as DNSPs.

The AEMC made similar observations in the Chapter 6A transmission determination in 2006 when the revenue cap form of price control was mandated for TNSPs in the NER.[20]

An earlier report from the Expert Panel on Energy Access Pricing also cited the fact that the costs of lumpy transmission investment are not related to individual demands, as to why a revenue cap is preferred for TNSPs. In particular, the Expert Panel noted that:

> "[T]he principal reason for applying revenue caps in electricity transmission is the lumpy nature of the capital investment and the very weak relationship between annual changes in transmission cost and demand or output. Transmission service providers also have only limited ability to influence the demand for their services." [21]

In light these reasons, we do not consider it appropriate to change the use of revenue caps for TNSPs at this time. Unless TNSPs can recover their charges directly from consumers, the potential benefits of a WAPC control mechanism for TNSPs would be limited.

19 Grid Australia submission, pp. 2-4.

20 AER, *National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18 – rule determination*, 16 November 2006, pp. 40-41.

21 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p. 114.

2.6.2 Choice between revenue cap and WAPC for DNSPs

As noted above, the AER in its most recent consideration of this issue for the New South Wales DNSPs has expressed a view that a revenue cap is superior to a WAPC in terms of recovering efficient costs, but inferior in terms of price stability and efficient pricing incentives.[22] The AER has concluded that, on balance, a revenue cap would be more appropriate for these DNSPs at the current time.[23]

A number of DNSPs questioned AER's position in their submissions to this review. For example, SP AusNet argued that the AER's conclusion that there is little practical benefit in DNSP pricing from WAPC is contradicted by evidence and pointed to the removal of cross subsidies in their areas.[24] SP AusNet also stated that the roll out of smart meters in Victoria will enable more cost reflective network tariffs and that WAPC would ensure that the networks have the right incentives to do such pricing.[25]

The Victorian DNSPs joint submission argued that the risks with demand forecasts are symmetrical and under a WAPC, DNSPs would have the incentive to best manage those risks.[26] Jemena also argued that, since a large proportion of capex is dependent on growth and augmentation capex, a WAPC form of control is more appropriate than a revenue cap.[27]

We note that the general adoption of revenue caps for DNSPs would impact on their incentives to undertake demand management in two opposite ways:

i. It would remove the disincentive they otherwise face as a result of the lost revenue associated with demand management; but

ii. It would lessen their incentive to price at efficient cost. Efficient pricing structures would encourage demand management as a result of the price signals provided.

We note that under the current NER, the allowed rate of return is to be determined commensurate with the efficient financing costs of a benchmark entity with a similar degree of risk as the NSP. As a consequence, the AER is able, under the current NER, to consider whether differences in the control mechanism applied to an NSP affects the degree of risk they face, and to reflect this in its decision on the allowed rate of return.

We consider that it is appropriate that the NER continues to provide the AER with the choice to determine the appropriate control mechanism to apply to DNSPs, given the pros and cons associated with different forms of control, and the competing incentives under each.

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22 AER, *Stage 1 Framework and approach paper - Ausgrid, Endeavour Energy and Essential Energy*, March 2013.

23 Id., pp.48-50.

24 SP AusNet submission, p.5.

25 Ibid.

26 Joint submission from Victorian distribution businesses, pp.3-4.

27 Jemena submission, p.5.

Overall, the current frameworks provide the AER with the ability to consider the risks and impacts on consumers and NSPs in relation to variations in demand. The AER can consider these issues across the range of decisions and their interactions including rate of return, control mechanism and the approval of tariff structures.

Furthermore, the adoption of the AEMC's *Power of Choice* review recommendations on distribution pricing principles and changes around the network tariff consultation process will assist in further improving the network pricing outcomes. These proposed changes would directly address the issue of providing efficient tariff structures in the face of uncertain future demand levels.

3 Demand risk and efficient network expenditure

Summary

- Demand risks arise in the regulatory frameworks because NSPs' allowed revenues are determined on the basis of a forward-looking assessment by the AER of the efficient level of expenditure over the forthcoming regulatory control period.
- The impact of this demand risk on consumers and NSPs depends on how the NSPs change their planned capex to reflect the differences in demand.
- Consumers see the impact of this at the end of the five yearly regulatory control period, when consumers either receive or pay a share of the under or over spend by the NSP during the regulatory control period. Prices in the next regulatory control period will reflect these adjustments.
- Evidence suggests that even though demand related capex, such as growth and augmentation capex, is a substantial contributor to the value of the regulatory asset base of an NSP, it has only a relatively small effect on costs in the period in which the NSP's allowance is included in revenues; and hence on consumer prices.
- Differences between NSPs' forecast and actual demand do not suggest a clear evidence of a tendency to under or over forecast. There are a range of different factors, including those provided by the regulatory arrangements, reliability obligations and shareholder governance, which affect the forecasting incentives of NSPs.
- Following changes made under the *Economic Regulation of Network Service Providers* rule change in November 2012, the regulatory frameworks gives AER the means and powers to assess the NSP's forecasts and substitute its own forecasts where appropriate.
- The NER gives the AER the ability to apply a range of uncertainty mechanisms such as cost pass through events and contingent projects during a regulatory control period. These mechanisms can be used in conjunction with the capex incentives to address uncertainty in relation to future demand forecasts.
- The current regulatory framework provides adequate tools to the AER to financially incentivise NSPs to adapt their capex programs to changes in demand occurring during the regulatory control period. Under the AER's proposal for using these tools, NSPs would have a strong incentive not to spend any more capex than is necessary at any time during the regulatory control period and irrespective of whether the NSP's actual capex is higher or lower than the forecast reflected in the AER's determination.

3.1 Impact of demand risk on consumers and NSPs

Demand risks arise in the current transmission and distribution regulatory frameworks because NSPs' allowed revenues are determined on the basis of a forward-looking assessment by the AER of the efficient level of expenditure over the forthcoming regulatory control period. This forward looking assessment will reflect assumptions about expected future demand levels – both at a network and local level plus connections. Actual demand during the current regulatory control period may turn out to be higher or lower than these assumptions. Setting revenues in advance is an inherent feature of an incentive based regulatory framework, and provides the NSP with an incentive to meet its service and reliability obligations at least cost, as it can increase its profits by doing this. Consumers benefit in future regulatory control periods if NSPs reveal more efficient ways to provide services.

The impact on consumers and NSPs from the use of demand forecasts depends on how the NSPs change their planned capex to reflect the differences in demand.

If demand growth is higher than forecast at the start of the regulatory control period, the NSP may need to incur additional capex. If NSPs are unable to recover at least part of the costs of this additional capex, then their incentives to undertake efficient expenditure will be affected. Furthermore, consumers may suffer from lower quality of service or increased risk of reliability problems if the NSP decides not to carry out such additional expenditure.

Likewise, allowed expenditure might be set too high if actual demand turns out to be less than forecast demand. In this situation, how the frameworks incentivise the NSP to adjust their capex program to actual demand will be important in ensuring that the NSP only invests as required to meet the lower demand circumstances, and that consumers benefit from the downturn in demand.

3.2 Materiality of the link between demand forecasts and network capex

Network capex can be split at a high level into system and non-system. System is further broken into growth, augmentation and replacement activities. Non-system includes items such as administration buildings, training and information technology infrastructure.[28]

We note that there are no strictly defined terms for network expenditure categories.[29] As such, for the purpose of this Advice, we have adopted the following definitions on the sub-categories of capex:[30]

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28 AER, *Better regulation – expenditure forecast assessment guidelines for electricity distribution and transmission*, December 2012, Appendix B; and Parsons Brinckerhoff, *Report on capital expenditure overspends by electricity network service providers*, Report for the AEMC, 16 August 2012, p. 10.

29 The AER is currently consulting on how best to categorise NSP proposed expenditures as part of its Better Regulation program of work.

30 Each network has unique requirements and not all capex activities may fit neatly into these categories.

- *Growth*: new customer connection requests and upgrading of the network to facilitate new connections. This is net of consumer contributions.
- *Augmentation*: the need to install or upgrade assets to increase network capacity in response to growth in peak demand or movement of demand around the network.
- *Replacement:* capex required to replace ageing assets.

Under these definitions, demand related capex would include growth capex and augmentation capex.

In its submission, the Energy Users Association of Australia (EUAA) provided some estimates on the proportion of total capex attributed to augmentation capex.

Table 3.1 EUAA's estimate of the average annual capex and augmentation capex per year

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

Source: EUAA submission, p.2.

According to EUAA, augmentation capex as a percentage of total capex is approximately 26 per cent in distribution, but much larger (approximately 60 per cent) in transmission as shown in Table 3.1. The percentage of augmentation capex in distribution only shows augmentation capex as a percentage of total capex, and does not include customer connections growth expenditure. Inclusion of expenditure on customer connections growth would increase this percentage from around 25 per cent to over 50 per cent for DNSPs.

Table 3.2 provides an example of the relative weight of each capex sub-category to total capex for the five Victorian distribution networks. Again, as there are no strictly defined categories for network expenditure across NSP regulatory proposals, we understand that the Victorian DNSP categories are broadly consistent with our definitions.

Table 3.2 Victorian DNSPs' capex categories as a proportion of total capex for 2011 to 2015 regulatory determinations

Category	CitiPower	Powercor	Jemena	SP AusNet	United Energy
Reinforcement (Augmentation)	34%	20%	22%	29%	26%
Demand connections (Growth)	27%	32%	21%	26%	14%
Reliability and quality maintained (Replacement)	28%	30%	27%	32%	34%
Other	11%	19%	30%	12%	25%

Source: AER 2010, Victorian electricity distribution network service providers' distribution determination 2011-2015, Final Decision, p. 384.

Augmentation capex ranges from 20 per cent to 34 per cent, growth in new connections range from 14 per cent to 32 per cent, while replacement capex is relatively more consistent between 27 per cent and 34 per cent. We also note the degree of difference between each network, particularly for augmentation and growth capex.

Table 3.3 sets out modelling undertaken by the AER that estimates the impact of demand related capex on network revenues in current regulatory control periods of various DNSPs. It also presents the impact on an average customer's bill if the demand related capex allowance is removed from the regulatory determination. It shows that the proportion of allowed revenue attributable to growth capex ranges from 2.2 per cent to 11.5 per cent over the current regulatory control period for each NSP.

Table 3.3 Impact of demand related capex on network revenues and prices

Jurisdiction	Network	Current total unsmoothed revenue ($m nominal)	Revenue related to growth capex (%)	Impact per customer (c/Kwh)	Impact average retail price in 2012-2013 (%)
NSW	Ausgrid	$8,515	6.9%	0.8	2.5%
	Endeavour Energy	$4,790	6.1%	0.7	2.4%
	Essential Energy	$6,099	5.1%	1.0	3.2%
QLD*	Energex	$7,011	11.5%	1.2	4.4%
VIC	CitiPower	$1,190	9.8%	0.3	0.9%
	Powercor	$2,512	7.7%	0.3	1.0%
	Jemena	$994	2.2%	0.1	0.3%
	SP AusNet	$2,446	7.8%	0.3	1.0%
	United Energy	$1,675	5.7%	0.2	0.6%

Source: Unpublished AER analysis; AEMC analysis. *Figures for Ergon Energy were not available.

With respect to the impact on an average customer's bill, Table 2.3 shows that the complete removal of growth capex is estimated to decrease costs by between 0.1c/Kwh and 1.2c/Kwh or between 0.3 per cent and 4.4 per cent. Modelling also shows that a 20 per cent difference between actual and forecast demand only represents up to around 0.75 per cent of consumer retail prices, and substantially less in some jurisdictions.

The impact of demand related capex for TNSPs was also illustrated by Electranet's recent draft revenue decision by the AER. At the stakeholder workshop, Grid Australia highlighted that in Electranet's case, a 10 per cent reduction in forecast peak demand resulted in a 20 per cent fall in capex, but only 1-2 per cent impact on revenues.[32]

Such evidence suggests that even though demand related capex is a substantial contributor to the value of the RAB, it has only a relatively small effect on costs in the period in which its allowance is included in revenues; and hence on consumer prices. This is because, while the capex is spent throughout the regulatory control period, it is recovered over the lives of the assets and so extends well beyond the regulatory control period to which that growth capex relates.

Network expenditure will continue to be primarily driven by growth and augmentation capex requirements. The extent to which these factors contribute to future network expenditure will be influenced by a number of external factors, including:

- Changes to government mandated network planning and security standards. Any reduction in the stringency of mandated network planning and security standards, such as those in place in Queensland and New South Wales, may significantly reduce the amount of investment required to comply with these standards.
- A potential reduction in economic activity in the wake of ongoing effects of the global financial crisis, which may serve to lessen electricity demand and possibly peak demand growth. This may result in network augmentation projects being deferred or scaled down.
- If the mining and resources sector remains strong, this could see large new loads in rural or regional areas. This has already been experienced in recent years in Ergon Energy's distribution area and could continue into the future. This may put upward pressure on rural network investment which in general is more expensive than urban network investment, particularly on a per unit basis.
- Potential for increased demand side participation such as load management schemes and increased penetration of embedded generation. Both of these factors may serve to lessen electricity demand and possibly peak demand growth in localised areas, thereby resulting in some network augmentation projects being deferred or scaled down. However, in the absence of demand side participation, the ongoing uptake of energy intensive appliances such as air-conditioning and pool pumps is likely to increase localised peak demands on the network and hence the need to invest in additional network capacity.
- Continued population growth is likely to increase localised peak demands on the existing network and drive the need to growth capex. More demand side participation would not be effective at deferring or avoiding network expenditure to connect and supply electricity to new customers.
- An increased penetration of electric vehicles has the potential to significantly increase electricity consumption and the average demand on electricity networks. However, electric vehicles may not have a significant impact on peak demand if

32 Presentation by Rainer Korte, Grid Australia, Workshop held on 28 February 2013.

appropriate load management schemes are implemented to coincide with their introduction.

3.3 Do NSPs have an incentive to over-forecast demand?

In assessing whether demand risks caused by differences in demand levels are adequately addressed within the current regulatory framework, we have evaluated whether the current framework has a bias to setting allowed revenues on over-stated demand forecasts.

Under the incentive regulation frameworks, all NSPs have an incentive to over-forecast those factors which relate to their approved expenditure. To the extent to which demand drives allowed expenditure (and hence revenue), then the NSP would have an incentive to over-forecast demand.

The degree of the inherent incentive to over-forecast demand will depend upon the design of the regulation frameworks and how that frameworks exposes the NSPs to the risks, in terms of profit or loss, of actual expenditure needs being more than or less than allowed expenditure. Since NSPs are faced with rewards where they underspent and penalties where they overspend, the incentive to over-forecast stems from both trying to minimise risk, and maximise reward payments. Uncertainty mechanisms are used as complementary tools to mitigate this risk which could dampen the incentive.

The incentive will also depend upon a particular NSP's attitude to risk - which can differ across businesses. However, even where an NSP is less risk averse, securing a higher expenditure projection still leaves greater room to outperform and receive the benefits.

The incentive to over-forecast is not unique to the incentive regulatory framework. Irrespective of what type of regulatory approach is adopted, NSPs will always have the incentive to over-forecast those factors which determine their allowed revenue. For example, under cost of service regulation, the NSP's profit can still depend upon the volume of projects it is permitted to undertake (ie through the cost of equity component of the rate of return allowance).

This incentive to over-forecast cannot be totally eliminated from network regulation. However, under the current framework in the NER there are two main ways in which the regulatory framework safeguards consumers against this incentive to over-forecast:

- it gives the AER the means and powers to assess the NSPs demand forecasts and substitute its own forecasts where appropriate; and
- the frameworks recognises that incentive regulation is a repeated process every regulatory control period, and the AER can make use of the difference between actual outturn demand levels and the allowed forecasts during the previous regulatory control periods in assessing the NSP's forecasts going forward. If the NSP consistently over-forecasts, and cannot point to valid reasons why outturn demand was lower than its forecasts, then the AER is more likely to not believe the NSP's forecast and substitute its own or ask the NSPs to re-submit.

This incentive to over-forecast can be offset by the fact that the same factors which drive expenditure may also be used in setting the price path (where the NSP is under a WAPC form of regulation). Such factors include consumer numbers, average demand, and where the NSP has demand charges, peak demand. There is an incentive for the NSP to under-forecast such factors at the time of the regulatory determination, as lower forecasts will lower the X factors calculated, and therefore increase the CPI-X cap on annual price increases.

The degree to which there is commonality between the factors used to a) justify expenditure and b) to set prices and revenue, then the NSP would face incentives in the opposite direction. What incentive dominates would depend upon which one influences the NSP's profit the most.

In addition to the incentives that arise from the regulatory arrangements there may be other incentives on NSPs that affect their incentives to over or under forecast demand. The evidence discussed below suggests that this may be the case given there is no clear evidence that NSPs have persistently over or under forecast demand.

Historical actual demand data does not suggest that in practice NSPs continuously over-forecast demand. More than anything, there is a pattern of variability in actual demand that is either less than, or greater than, forecast demand. There is no evidence of a bias in the network determination processes towards approving an inflated level of demand forecasts, and hence higher than required capex allowance (see section 1.2 and Appendix A).

The AER already has the ability to interrogate demand forecasts submitted by NSPs as part of their regulatory proposals and substitute its own forecasts. This was evident in the recent Powerlink final decision for its 2012-17 revenue determination and Electranet's draft decision for its 2013-18 revenue determination. In the Powerlink decision, the AER reduced Powerlink's demand forecast by 5.7 per cent reducing load driven capex by $451m over the regulatory control period.[33] In the case of ElectraNet's draft decision, the AER reduced its demand by 13.8 per cent, reducing ElectraNet's capex forecast by $103.7m over 2013-18 regulatory control period.[34]

The AER's capacity to interrogate, review and amend expenditure forecasts submitted by the NSPs has been further enhanced by the recent changes made in the *Economic Regulation of Network Service Providers* rule change.

3.4 Incentives to adjust expenditure plans

The incentive arrangements reflected in the current NER provide NSPs with incentives to reduce expenditure below the capex allowance where possible, including where peak demand forecasts are revised downwards from those adopted at the time of the regulatory determination. Appendix B provides a detailed summary of the current arrangements in the NER.

33 AER, *Powerlink transmission determination, 2012-13 to 2016-17*, Final Decision 30 April 2012.

34 AER, *ElectraNet transmission determination, 2013-14 to 2017-18*, Draft Decision, 30 November 2012.

The NER also provides the AER with an ability to develop an overall capital incentive expenditure approach. The AER is currently in the process of developing its approach, following the changes made to the NER in November 2012.[35]

The strength of the incentives for NSPs to reduce their expenditure where demand falls will also be affected by the AER's decision on the allowed rate of return.

Under the current NER, consumers benefit from reductions in expenditure when demand falls below forecasts, as the actual (lower) amount of capex is rolled into the RAB and reflected in prices at the time of the next review, rather than the higher capex level initially forecast.

Where peak demand increases above the level forecast at the time of the determination, the current NER continue to provide incentives for NSPs to try to accommodate that increase within the capex allowance set. However, where this is not possible, the NSP is subject to a penalty for any overspend. This penalty is necessary in order to retain the symmetry of incentives under the NER. The magnitude of this penalty could be quite substantial; with the NSP facing a loss of around 20-30 per cent of the amount of over-spend if it occurs in the second year of the regulatory control period.[36] Under the AER's proposal, NSPs would have a strong incentive not to spend any more capex than is necessary at any time during the regulatory control period and irrespective of whether the NSP's actual capex is higher or lower than the forecast reflected in the AER's determination.

The uncertainty mechanisms in the NER are also able to be used, to differing extents, to address uncertainty in relation to future demand forecasts.

- The contingent project mechanism in the NER provides a potential mechanism to manage the uncertain impact on the need and timing of specific network investments arising from material differences between actual and forecast demand where appropriate triggers can be identified, and may enable more conservative demand forecasts to be adopted at the time of the determination.
- The capex re-opening provisions in the NER could also be used to address the impact of a greater than anticipated increase in demand that necessitated a substantially higher level of capex. However, we note that the threshold for the use of the re-opening provisions is set such that they are triggered only as a last resort, in response to significant external changes, and only for increases in expenditure.
- It would also be open to NSPs to propose a cost pass through event to cover a "demand forecasting event". Such an event would need to be approved by the AER, having regard to the nominated cost pass through considerations in the NER.

However, it is also important to note that the intention of such uncertainty mechanisms is that they are used only in specific, limited circumstances. This is important in order to preserve the effectiveness of the incentive-based arrangements, under which the NSPs are expected to manage the on-going risks during the regulatory control period, including risks associated with changes in actual demand. More extensive use of the

35 AER, *Better Regulation – Expenditure incentives guidelines*, Issues Paper, March 2013.

36 Id., p.17.

uncertainty mechanisms would lead to more frequent revisions to allowed revenue during the regulatory control period, undermining the efficiency incentives for NSPs as well as resulting in an increased administrative burden and greater volatility and unpredictability for consumers in relation to network prices.

The requirement in the NER to apply the relevant regulatory investment test (ie the RIT-T or RIT-D) represents a further point at which the need for a specific network investment is assessed and subject to public consultation, based on the most recent forecasts of future demand available at the time the test is applied. This is a public accountability mechanism to illustrate whether NSPs are using the most up-to-date information when making investment decisions part way through regulatory control periods.

3.5 Options to strengthen the link between efficient expenditure and changes in demand

We have considered whether changing the capex re-opening provisions to include downside events and expanding the scope of contingent projects could assist in managing the expenditure and revenue risk associated with changes in demand within a regulatory control period.

We have also undertaken a high level evaluation of four potential approaches to change the capex incentives facing NSPs in a manner which could strengthen the link between its expenditure plans and changes in demand. These include:

1. the removal of under-utilised assets from the RAB;
2. a project-by-project assessment of demand-driven capex at the time at which the capex is needed, to replace the current assessment of the total capex program over the regulatory control period;
3. an adjustment to the calculation of efficiency gains or losses over the regulatory control period to remove the windfall impact associated with changes in demand; and
4. a “revenue driver” approach to adjusting allowed revenues at the next regulatory determination.

Some of these approaches, or variants of an approach, were raised by stakeholders during this review. The first option has been specifically raised for our consideration in the Request for Advice. Option two attempts to address the issue through decreasing the time gap between determining the allowed expenditure and the need for investment, while options three and four apply a form of reconciliation (“true up”) to allowed revenues to account for differences between forecast and actual demand.

These options are briefly discussed below. A more comprehensive assessment of the last four options is provided in Appendix C.

3.5.1 Incremental changes to uncertainty mechanisms

The capex re-opening provisions in the NER allows an NSP to apply to the AER to revoke and substitute a revenue determination, where an event that is beyond the reasonable control of the NSP has occurred during the regulatory control period and where the NSP proposes to undertake additional capex to rectify the adverse consequences of the event, which wasn't foreseen at the time of the regulatory determination.[37]

The capex re-opening mechanism is currently a one-way event trigger where the "event" may include "a greater than anticipated increase in demand". As a consequence, it cannot currently be used to re-open a regulatory determination where there has been a substantial reduction in peak demand over the period.

Another possibility could be to expand the scope of contingent projects mechanism so as to allow NSPs and the AER to use this mechanism more widely as a way to manage demand uncertainty. Recognising that the contingent project mechanism is a new addition to the regulatory frameworks for DNSPs, treating uncertain, demand-related projects as contingent projects and excluding them from the main expenditure forecast may allow more conservative demand forecasts to be adopted and preserve the incentives on NSPs to seek to defer or reduce spending in relation to non-demand related projects, in the event that actual demand is higher than forecast demand.

It is a potentially attractive proposition to allow the capex re-opening provision to be expanded to also include reductions in peak demand. The AEMC previously noted that the capex re-opening provisions are intended to be a last resort, only triggered by large, shipwreck-type events.[38] Indeed, to date the capex re-opening provisions have not applied in practice. As a consequence, the capex re-opening provisions are not intended to be primary mechanism to address the cost impact on NSPs of demand forecast changes.

It is therefore important to preserve the capex re-opening provisions to only those circumstances where changes in demand forecast were not able to be identified at the time of the regulatory determination and so could not have been addressed via the inclusion of a contingent projects, and are of a size that would warrant use of the "ship-wreck" provision.

Further complications would also arise if a demand downside provision were to be included. There would be no incentive on an NSP to seek a re-opener to reduce its capex allowance, and hence revenues within a regulatory control period, in the event of a substantial downturn in demand. As a consequence, downside events would need to be triggered by third parties or the AER.

It is also unclear to us which third party would have sufficient technical information to apply for the re-opener. The level of information asymmetry would make the exercise of seeking the NSP's capex allowance to be revised down a difficult task. It would also

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37 The capex re-opening are set out in sections 6A.7.1 and 6.5.5 of the NER. Refer to Appendix B for details on how this mechanism operates.

38 AEMC, *Draft Rule Determination, National Electricity Amendment (cost pass through arrangements for network service providers) Rule 2012*, May 2012, p.17.

be difficult to ascertain whether the downward demand is a one-off or representative of a downward trend.

With respect to broadening the use of the contingent projects mechanism, we are doubtful of the benefits this may provide. The use of the contingent project mechanism to address demand forecast uncertainty, outside of material and specific demand changes, may increase the administrative burden on the AER and NSPs, and represent a move away from the current arrangements under which NSPs bear a substantial degree of demand risk with respect to expenditure. The extent to which this is the case will depend on how frequently the contingent project mechanism would be expected to be triggered (as opposed to the number of contingent projects incorporated in a regulatory determination).

Furthermore, if contingent projects were to be used more frequently to adjust capex allowances within the regulatory control period, consumers are likely to see greater volatility in their prices as revenues get adjusted upwards following each contingent project determination. In addition, regulatory costs would increase for both AER and the NSPs.

We have concluded that changes to these mechanisms are not warranted at this time. Our main concern is that expanding the scope of these mechanisms would potentially undermine incentives under the current regulatory arrangements, and would conflict with original intent that these mechanisms only be used in limited and specific circumstances.

3.5.2 Removing under-utilised assets from the RAB

We have considered this option given that the Request for Advice asks us to consider "...improvements to the AER's ability to consider utilisation of previously approved capital expenditure." It was also raised by the EUAA in its submission to this review.[39]

Utilisation of previously approved capex raises the issue of whether the NER should permit the AER to optimise the RAB at the time of a regulatory determination by removing what is deemed to be underutilised capex.

In November 2011 the Major Energy Users Inc (MEU) submitted a rule change request to the AEMC for the inclusion of optimisation of the asset base in the NER. The MEU's proposed rule would have required the AER to periodically review the existing asset base and exclude assets that are un-used or underutilised from the RAB.[40]

In our assessment of the MEU's proposed rule change, we determined not to make a change in the NER to permit optimisation of the RAB, on the basis that such optimisation:

- could increase the risk to NSPs and therefore provide disincentives for future investment;

39 EUAA submission, p.3.

40 See AEMC, *Optimisation of Regulatory Asset Base and Use of Fully Depreciated Assets*, Rule Determination, 13 September 2012. The proposed rule also covered the replacement of fully depreciated assets which can be still be used.

- could increase the complexity, costs and resourcing of the regulatory process; and
- would require the AER to perform too detailed a role in approving a service provider's projects and plans.[41]

In our determination we noted that, unlike a competitive business, a regulated NSP has an obligation to invest to meet expected demand growth regard regardless of the likely risk, including the risk that expected demand does not eventuate. NSPs are not compensated for additional risk with a higher rate of return.

We remain of the view we reached in the MEU's proposed rule change that optimisation of the RAB would decrease the stability and predictability of the regulatory regime and provide disincentives for future investment.

While we did not make a rule as proposed by the MEU, we did introduce a limited form of ex post review in the *Economic Regulation of Network Service Providers rule change* that permits the AER the option to apply an ex post review to capex overspends by the NSP and reduce the roll-forward RAB by the overspend if deemed inefficient.

We had regard to the limitations and obligations placed on NSPs in its decision not to adopt asset base optimisation. We continue to consider this to be the most efficient means to introduce an ex post review into the regulatory frameworks.

3.5.3 Project by project assessment for all capex

We have also considered whether an approach to addressing differences between forecast and actual demand outcomes would be to adopt a project by project approach to the assessment of NSPs' demand-related expenditure. This would be in contrast to the current approach of approving an expenditure allowance over the entire regulatory control period, and leaving NSPs to manage the risks of meeting their actual expenditure requirements within this allowance.

Project by project assessment seeks to address the demand forecasting risk through decreasing the time gap between expenditure approval and commissioning of the network asset. Under the current arrangements a proportion of capex is being approved using demand forecasts developed in advance of the need for expenditure.

Such an alternative has recently been flagged by the Productivity Commission for the regulation of transmission networks, as part of its review on Electricity Network Regulation. Specifically, the Productivity Commission has suggested that all transmission projects above a certain threshold could effectively be considered as contingent projects. This is because of the difficulty of predicting exactly when investments are needed, the lead times required for transmission investment and the difficulties of developing incentive regulation for projects that are out in the future.[42]

The Australian Energy Market Operator's (AEMO) submission to this review also advocated a variant of the project by project mechanism for all material augmentation

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41 Ibid.

42 Productivity Commission, *Inquiry into Electricity Network Regulatory Frameworks*, Transcript of Proceedings at Canberra, 6 December 2012, p. 303.

capex.[43] Under this option, all material augmentation capex (above the regulatory investment test threshold of $5m) would be moved out of the five yearly regulatory reset process and into a modified contingent projects regime. The regulatory investment test process would then be applied to determine the most efficient project based upon the most recent demand forecasts. The most efficient project would then be submitted to the AER for approval.[44]

AEMO's proposal is framed for transmission augmentation expenditure, although AEMO also suggests that it could also be applied to distribution, particularly in investment in sub-transmission assets by DNSPs. In this way, AEMO submit that the scope for consumers to incur costs unnecessarily will be minimised because consumers will only pay for the costs of projects demonstrated as being necessary and cost-efficient under the RIT based on the most up-to-date available information.[45]

Given the lead time for design, procurement, construction and commissioning, the timing of commitment to projects and thus expenditure will always be based on forecasts. There is always uncertainty about whether the forecast demand levels will turn out to be correct, and inevitably, forecast demand will always be different to outturn demand.

If there are a substantial number of projects subject to such project-by-project assessment, the overall time needed by the AER (or AEMO) to undertake the assessments will increase. As a result, there could be a risk of delay in project construction as a consequence of requiring a project by project assessment. Conversely, the AER/AEMO may have to start such an assessment further in advance of when the project is expected to be needed, re-introducing the scope for there to be subsequent changes in demand forecasts, and so reducing the value of the project by project approach as a mechanism to address such demand uncertainty.

We do not consider a project by project assessment to be a viable option. We also do not endorse the Productivity Commission's draft position for an expanded contingent projects framework or AEMO's proposed approach for TNSP augmentation capex. Briefly, the reasons why such an approach would be difficult to implement include:

- a trigger will need to be specified for *all* capex projects;
- it could negatively affect the incentive regulatory frameworks creating extra risks for NSPs and consumers;
- the AER/AEMO will essentially be making the investment decisions instead of the NSP thereby changing the accountability of complying with reliability standards;
- it will create network pricing uncertainty and variability; and
- it would be an administratively complicated and resource intensive exercise.

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43 AEMO submission.

44 Id., p.12. Under AEMO's proposal, current arrangements will continue to be applied to existing network assets including replacement and refurbishment, and any augmentation projects that fall under the RIT threshold.

45 Id., p.13.

Under such project by project approaches, the AER or AEMO could effectively become the decision maker on whether specific projects go ahead. It would not be appropriate for a regulator or a market operator to be in this position, as they are not exposed either to the commercial risks or the reliability obligations faced by the NSPs. As a consequence, NSPs would no longer be accountable for complying with reliability standards and the network reliability standards framework would need to be revised to reflect this.

In addition, a project by project assessment approach assumes that it is possible to separately identify capex projects which are solely driven by increase in forecast demand. It is our understanding that many network investments are undertaken in response to several drivers (such as replacement of assets and the need to meet reliability standards), which need not all be related to demand. It is common for NSPs to align the timing of replacement programs with the reinforcement needs of the network.

We also note that these types of approaches takes away any ability or incentive for a NSP to try and manage within its overall revenue for augmentation projects, including re-prioritising between years or between different types of expenditure. The work undertaken as part of the *Economic Regulation of Network Service Providers* rule change indicated that NSPs do in practice undertake such re-prioritisation.[46]

3.5.4 Minimising windfalls from changes in demand

In its submission to the Productivity Commission's Draft Report on Electricity Network Regulation, Grid Australia proposed a mechanism to identify and neutralise the windfall gain/loss resulting from any difference between forecast and actual demand, as part of the operation of a capex incentive scheme.[47] Grid Australia also referred to its proposal to the Productivity Commission at the AEMC's stakeholder workshop.[48] Grid Australia's proposed mechanism can be summarised as follows:

- Prior to the start of the regulatory control period, forecast network augmentation is calculated using the best forecasts of demand available at the time.
- At the end of the regulatory control period, an adjusted forecast of expenditure is calculated by re-running the models that were used to calculate forecast augmentation using actual demand figures for the period.
- Business-induced efficiencies are calculated as the difference between actual augmentation expenditure and adjusted forecast expenditure.

Grid Australia's proposed approach would effectively correct for the windfall gain or loss component of an NSP's capex underspend or overspend, in calculating the reward or penalty to apply to an NSP under a capex incentive scheme.

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46 See Parsons Brinckerhoff, *Report on capital expenditure overspends by electricity network service providers*, Report for the AEMC, 16 August 2012.

47 Grid Australia, *Electricity Network Regulation, Submission in response to Productivity Commission Draft Report,* 30 November 2012, pp. 18-19.

48 Presentation by Rainer Korte, Grid Australia, Workshop held on 28 February 2013.

Under the existing NER, the AER is able to develop a capital expenditure sharing scheme, defined as a scheme that provides an NSP with an incentive to undertake efficient capex during a regulatory control period. The introduction of a mechanism to adjust the calculation of efficiency gains to remove the impact of windfall gains/losses associated with differences between forecast and actual demand would appear to fall within this definition.

There are a number of issues with this approach that would have to be addressed before it could be applied. The obvious issue with this option are the reliance on modelling to determine the gains and losses. In addition, this option assumes that differences between forecast and actual demand are not within the control of the NSPs. This may not be the case, especially for distribution networks. Further analysis is required on how such an option would affect the incentives on networks and also the impacts on consumers.

We consider that it is open to the AER to consider whether such a mechanism should be adopted as part of the capex incentive schemes for NSPs. Although we note that in its Issues Paper on expenditure incentives the AER has not yet discussed such a scheme.[49]

3.5.5 Linking allowed revenues to actual outturn demand

We have also given consideration to whether there might be a way to link allowed revenues to actual outturn demand under the current frameworks. One approach might be a "revenue driver" approach that links an NSP's allowed revenue to actual outturn outcomes via an adjustment to allowed revenues at the time of the next regulatory determination.

The application of a revenue-driver approach to demand related capex would entail the revenue an NSP receives being linked to differences between forecast and actual demand measures such as total consumption, peak demand and customer numbers for a number of pre-defined, demand related capex. The NSP's allowed revenue would then be adjusted at the time of the next regulatory determination to reflect differences between outturn demand (or revised forecast demand) and the original demand forecast, for each of these expenditures, at pre-defined 'unit costs'. Revenue adjustments would be symmetrical; revenue would be removed at the next determination where demand is less than forecast and additional revenue would be included where demand is greater than forecast.

Under a revenue driver mechanism, adjustments to an NSP's allowed revenue would only be made in relation to those cost elements directly affected by demand. The remainder of an NSP's allowed revenue would continue to be determined using the standard building block approach set out in the NER.

49 AER, *Better Regulation – Expenditure incentives guidelines*, Issues Paper, March 2013

We are of the view that it is open to the AER under the current NER to consider the merits and practicalities of a revenue driver approach in considering whether or not to introduce a capital incentive sharing scheme, and the appropriate form of such a scheme. Although we note that in its Issues Paper on capex incentives the AER has not yet discussed such a scheme.[50]

3.6 Recommendations

We are recommending no changes to the NER in relation to managing the demand risk associated with differences between forecast and actual demand during the regulatory control period.

We consider that the current economic regulatory frameworks applying to NSPs following amendments made under the *Economic Regulation of Network Service Providers* rule change determination in November 2012 provides adequate and effective tools and mechanisms to the AER financially incentivise NSPs to adapt their investment programs to changes in demand occurring during the regulatory control period.

In particular, the AER has discretion to develop its approach to capex incentives, including its ability to introduce a specific capital expenditure sharing scheme, and is currently in the process of doing so. The AER also has the capability to make greater use of the contingent project provisions if it is uncertain about the accuracy of demand forecasts.

We also do not consider expanding the NER to allow the AER to do an ex post optimisation of NSPs asset base to reflect any underutilised assets tobe appropriate. We have previously considered this issue and did not make a rule because we considered that any benefits from removing underutilised assets from the asset base would be outweighed by additional costs faced by consumers because investors in the NSPs would require a higher rate of return to recognise the increased risk of not recovering the costs of previous investments.

Furthermore, changing the regulatory frameworks for revenue determinations again risks undermining investor certainty following significant changes introduced in the frameworks in November 2012 as part of the *Economic Regulation of Network Service Providers* rule change determination.

The continuing application of the regulatory investment tests for both transmission and distribution will improve the transparency of demand considerations as part of network planning processes.

We also note that are a number of other modifications of the regulatory framework being considered in other review processes could help to further minimise demand risk. The AEMC has recently completed its *Transmission Frameworks* review and in the process of its reviews into distribution and transmission reliability standards. The distribution and transmission reliability standards review could address the need for reliability requirements to remain appropriate in light of changing demand conditions.

50 Ibid.

A Demand and network revenues

Summary

- The revenue that a network is allowed to recover over a regulatory control period broadly consists of a regulatory return, operating costs and depreciation. The contribution of the regulatory return and depreciation to allowed revenues is related to growth in network capex.
- Network capex generally comprises augmentation to meet peak demand, growth in new customer connections and replacement of ageing assets. Forecasts of peak demand growth and customer connection growth (growth capex) are required for the regulator to estimate an NSP's efficient level of expenditure over a regulatory control period.
- Evidence suggests that while growth capex is a substantial contributor to the RAB, it has a relatively small effect on consumer prices in the period it is incurred. This is because the capex is recovered over the lives of the assets and so extends well beyond the regulatory control period to which that growth capex relates.
- The long term trend of annual energy growth in the NEM is decreasing, although there is a high degree of volatility between years. Summer peak demand growth has been more variable, with no clear trend upward or downward. Preliminary data points to a reversal of the recent fall in summer peak demand.
- It is likely that a number of factors are making peak and annual energy more difficult to forecast. These include: the uptake of solar PV and energy efficiency, structural changes underway in the Australian economy and residual impacts from the global financial crisis. Greater use of DSP may also begin to contribute to uncertainty around demand forecasting, while the adoption of smart meters might provide forecasters with more accurate and robust data, over time.

This Appendix discusses the extent to which network revenues are driven by changes in demand. It is broken into two sections, as follows:

- Section A.1 describes how network costs and allowed revenues depend upon forecast energy and peak demand; and
- Section A.2 analyses changes in energy and peak demand growth over time and discusses whether demand is becoming more difficult to forecast.

A.1 How network costs and allowed revenues depend upon forecast energy and peak demand

The AER approves the revenue a network business is allowed to recover over a regulatory control period by estimating its efficient costs. At a high level, network costs consist of a regulatory rate of return, operating costs and depreciation.[51] Regulatory rate of return reflects cost of capital and return on assets, and depends on the rate of return and value of the asset base. Operating costs are expenditure required to operate and maintain the network appropriately to meet expected demand. Depreciation is the number of years over which capex is recovered based on the expected life of each asset.

Capex influences network revenues through depreciation and the regulatory return. Increased capex will be reflected in higher depreciation and therefore higher allowed revenues to recover the costs associated with the investment. However, as most capital intensive network assets, such as substations and transformers, have lives of over 40 years, these costs are recovered over a long time frame.[52] Capex also increases the value of a network's asset base over which the regulated return is calculated. An increase in the value of the asset base will increase the regulatory return and therefore allowed revenue.

Capex is used to install, upgrade and replace the assets that transport electricity. A forecast increase in peak demand, and/or movement of demand around the network, may require the NSP to augment the network (increase its capacity) to ensure customer load is met at the regulated measure of reliability. This is referred to as augmentation capex and is distinct from growth capex, which is customer driven and includes the installation of new connections and extension of the network. A further distinction is that augmentation expenditure has wider network benefits than expenditure specific to the connection of individual or a small number of customers.

Forecasts of peak demand and annual energy are used by the AER to estimate efficient capex and approve network prices. Summer and winter peak demand is the key driver of augmentation capex, while annual energy forecasts are used to convert revenues to prices.[53] Growth capex related to new customer connections is estimated based on forecasts of dwelling construction, population growth and expected economic activity within the network region.[54] If forecasts of peak demand and new connections differ from outturn, NSPs may under-or over-spend within the regulatory control period.

Network revenues are set based on a forward-looking assessment of the efficient level of costs, and therefore expenditure, over the regulatory control period. As forecasts will inevitably differ from outturn, there is a degree of uncertainty and risk assumed by NSPs and consumers. How these risks are apportioned is discussed in chapters 2 and 3.

It is important to note that the AER does not approve specific projects, but provides NSPs with discretion as to what projects they undertake. This is a fundamental part of incentive based network regulation, as it allows NSPs to search for efficiencies that ultimately benefit consumers and NSPs.[55]

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51 It also incorporates any adjustments from incentive mechanisms and under- or over-recoveries from the previous regulatory control period.

52 AER 2008, *New South Wales draft distribution determination 2009-10 to 2013-14*, p. 215.

53 Id., p. 84.

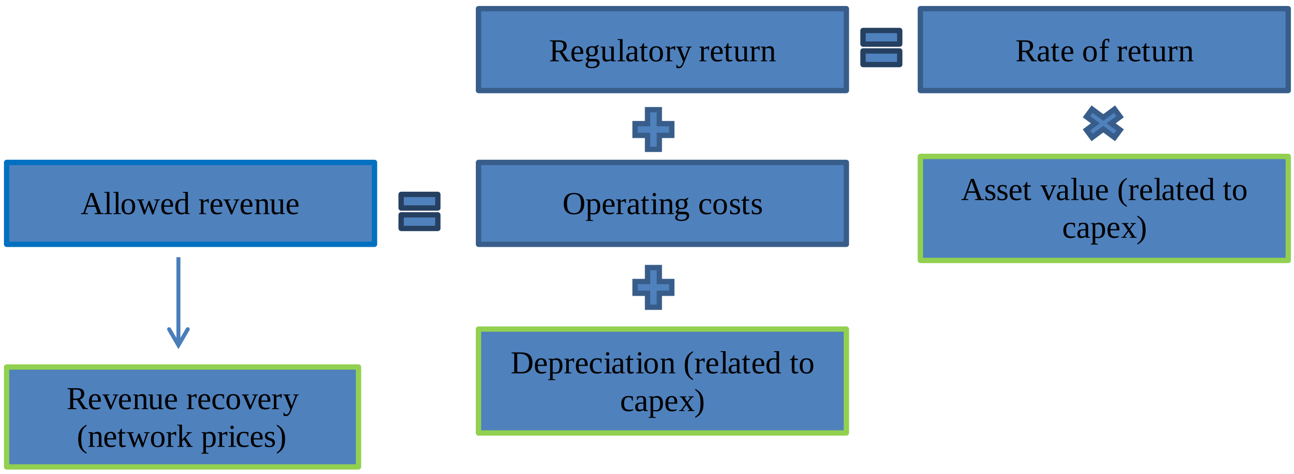
54 Id., p. 87-88.

55 Productivity Commission 2012, *Electricity Network Regulatory Frameworks*, p. 178.

In summary, NSPs' revenue is determined by estimating the return on capital, operational expenditure and depreciation of an efficient network business over the regulatory control period. Changes in capex influence network costs, and therefore revenues to be recovered from consumers, through depreciation and regulatory rate of return. Capex is estimated based on forecasts of peak demand and customer connections, while forecasts of annual energy are used to set network prices/tariff structures.

Figure A.1 is a simplified example of how demand forecasts are related to network costs and how these form allowed revenues. The following sections will discuss the relationship between allowed revenue, capex and demand forecasts in more detail.

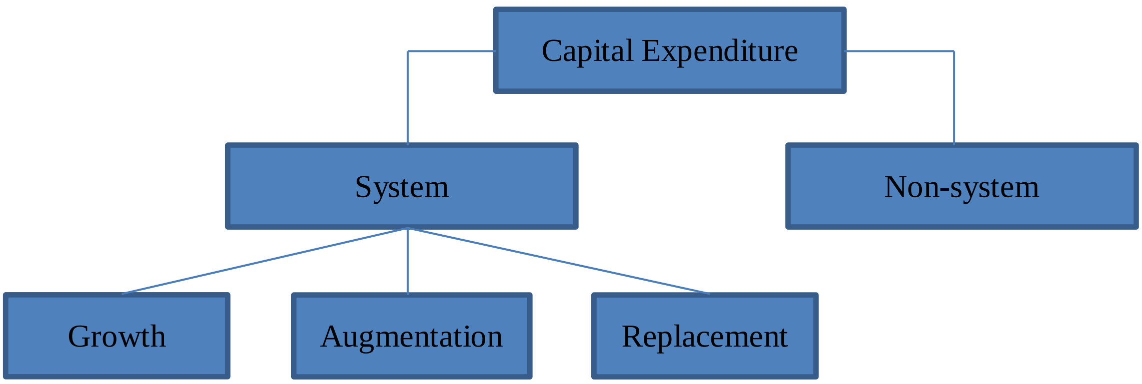
Figure A.1: Simplified building blocks of network allowed revenues



A.1.1 Capital expenditure

Network capex can be split at a high level into system and non-system, as illustrated in Figure A.2. System can then be further broken into growth, augmentation and replacement activities. Non-system includes items such as administration buildings, training and information technology infrastructure.[56]

Figure A.2: Sub-components of network capex



56 AER 2012, *Better regulation – expenditure forecast assessment guidelines for electricity distribution and transmission*, Appendix B; and ParsonBrinckerhoff 2012, *Report on capital expenditure overspends by electricity network service providers*, p. 10.

We note that there are no strictly defined terms for network expenditure categories. As such, for the purpose of this advice, system expenditure sub-categories are defined as follows:[57]

- *Growth*: new customer connection requests and extension and upgrading of the network to facilitate new connections.
- *Augmentation*: the need to install or upgrade assets to increase network capacity in response to growth in peak demand (or movement of demand around the network).
- *Replacement*: capex required to replace ageing assets.

Under these definitions, demand related capex includes growth capex and augmentation capex.

Table A.1 provides an example of the relative weight of each capex sub-category to total capex for the five Victorian distribution networks.[58] Again, as there are no strictly defined categories for network expenditure across NSP regulatory proposals, we understand that the Victorian DNSP categories are broadly consistent with our definitions.

Augmentation ranges from 20 per cent to 34 per cent, growth in new connections from 14 per cent to 32 per cent, while replacement is relatively more consistent between 27 per cent and 34 per cent. We also note the degree of difference between each network, particularly for augmentation and growth.

Table A.1 Victorian DNSPs' capex categories as a proportion of total capex 2011-2015 regulatory determination

Category	CitiPower	Powercor	Jemena	SP AusNet	United Energy
Reinforcement (Augmentation capex)	34%	20%	22%	29%	26%
Demand connections (Growth capex)	27%	32%	21%	26%	14%
Reliability and quality maintained (Replacement capex)	28%	30%	27%	32%	34%
Other	11%	19%	30%	12%	25%

Source: AER 2010, Victorian electricity distribution network service providers' distribution determination 2011-2015, Final Decision, p. 384.

57 The AER is currently consulting on how best to categorise NSP proposed expenditures as part of its Better Regulation program. The AEMC notes that in practice each network has unique requirements and that not all capital expenditure activities may fit neatly into these categories.

58 Net capital expenditure refers to total capital expenditure net customer connection contributions.

Our analysis focuses on how growth capex and augmentation capex are driven by demand levels. Non-system expenditure on the corporate functions of a NSP is not directly demand related, nor is replacement capex, which is mostly a function of the age of network assets.[59]

Growth

When analysing capex, it is important to differentiate between augmentation to meet peak demand and growth from new connections. For instance, peak demand may be falling, while growth in new connections is increasing. In this situation, the NSP may still be required to spend capital to expand and reinforce certain parts of the network to accommodate additional demand. Customer connection forecasts are also an input into annual energy forecasts, which are used to convert revenues to prices.

Table A.1 illustrates the degree to which growth capex contribute to the total capex of Victorian DNSPs. For some networks this constitutes over 30 per cent, indicating that changes to forecasts of new connections are likely to have a notable impact on required capex within a regulatory control period. The remaining capex allowance consists of spending associated with augmentation for peak demand, replacement of ageing assets and non-system expenditure.

Of the factors that contribute to changes in growth capex are considered by NSPs as generally not under their control. [60] This is because new connections are a function of economic growth, building approvals and government land release policies, and NSPs are obligated to respond if actual connections are above forecast. Furthermore, it is generally not possible to shift expenditure related to new connections into future regulatory control periods, which can make overspends more likely.

Table A.1 also highlights how growth capex is not always equal across a state. In Victoria, 14 per cent of United Energy's capex is growth related, this rises to 32 per cent for Powercor.

Growth capex will also vary within networks, as areas with a larger proportion of new land releases or residential apartments will grow faster than sections with established housing stock. NSPs must therefore forecast expected new connections for each localised area of the network that is served by a zone or bulk supply substation, as this will identify constraints and the need for augmentation.[61]

Augmentation

Forecasts of expected peak demand are a key driver for network augmentation investment. The forecast level of peak demand largely determines the need to upgrade transmission and distribution networks, in order to ensure that network reliability

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59 We note that replacement capital expenditure can be indirectly linked to demand forecasts as the life of some network assets decreases at a faster rate if equipment is operated above its factory rating.

60 ParsonBrinckerhoff 2012, *Report on capital expenditure overspends by electricity network service providers*, p. 32.

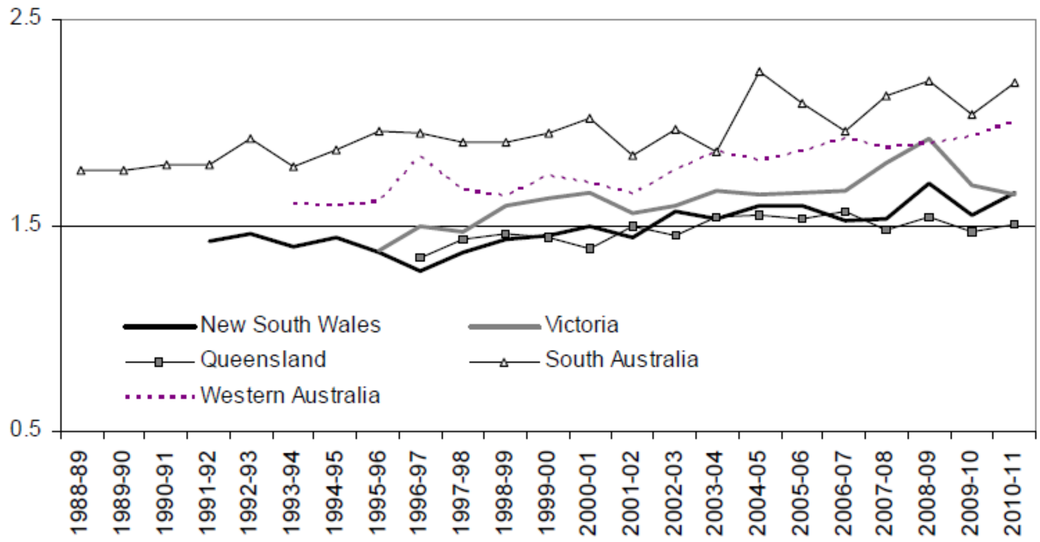
61 Ernst & Young 2011, *Rationale and drivers for DSP in the electricity market – demand and supply of electricity*, p. 19.

standards continue to be met. The level of capex expected to be required over a regulatory control period is therefore partly dependent on peak demand forecasts.

As can be seen from Figure A.3, peak summer demand to average annual demand has been trending up for over a decade. This graph shows the degree to which networks have been subject to increasing augmentation to meet growing peak demand. If the ratio was one, average demand on the network would equal peak demand. The higher the number, the higher peak demand is relative to average demand and the greater the requirement to augment the network.

Growth in peak demand in Australia has largely been driven by the residential sector, with the increasing penetration of air-conditioning a dominant factor. In recent times, peak demand has fallen across most jurisdictions (see section A.4.2) and evidence suggests that demand is becoming more difficult to forecast due to the uptake of solar PV and energy efficiency, as well as macroeconomic factors reshaping the economy. A run of mild summers has also likely been a contributor to the fall in summer peak demand. Changes to actual and forecast demand are discussed further in section A.4.2.

Figure A.3 Peak summer to average annual demand ratio



Source: Topp, V. and Kulys, T. 2012, P*roductivity in Electricity, Gas and Water: Measurement and Interpretation*, Productivity Commission Staff Working Paper.

Forecasting demand is a difficult task that poses risks for consumers and NSPs. If forecast peak demand is greater than outturn, then investment decisions based on forecasts will likely lead to over-investment, creating unused network capacity that consumers are required to pay for. On the other hand, where forecasts are underestimated and actual demand is greater, insufficient investment could occur, causing a decrease in network reliability and supply disruptions.

Peak demand forecasts are uncertain and will inevitably change over the regulatory control period. Therefore, the efficient level of augmentation capex required to be undertaken by NSPs may also differ from that approved at the time of the determination. While in some years augmentation capex may be greater than allowed by the AER, it may not always be inefficient, especially if peak demand is greater than forecast.[62] Furthermore, on a forward looking basis, an investment decision is efficient if made in good faith using the best available information at the time of the decision. The fact that subsequent events turn out different does not necessarily make the investment decision inefficient.

Augmentation expenditure accounts for between 20 per cent and 34 per cent of total expenditure for the Victorian DNSPs, as shown in Table A.2. The degree to which augmentation is linked to peak demand will depend on the existing configuration of each network, including spare capacity and location of constraints relative to the growth in peak demand. This most likely explains why augmentation is a larger component of some DNSP expenditure relative to others. It also highlights the importance of demand forecasting at the network level and below so that estimates of efficient expenditure are as accurate as possible by taking into account localised conditions.

Table A.2 sets out modelling undertaken by the AER that estimates the impact of demand related (growth and augmentation) capex on network revenues in current regulatory control periods of various DNSPs.[63] It also presents the impact on an average customer's bill if the demand related capex allowance is removed from the regulatory determination. It shows that the proportion of allowed revenue attributable to demand related capex ranges from 2.2 per cent to 11.5 per cent over the current regulatory control period.

Table A.2 Impact of demand related capex on network revenues and prices

Jurisdiction	Network	Current total unsmoothed revenue ($m nominal)	Revenue related to growth capex (%)	Impact per customer (c/Kwh)	Impact average retail price in 2012-2013 (%)
NSW	Ausgrid	$8,515	6.9%	0.8	2.5%
	Endeavour Energy	$4,790	6.1%	0.7	2.4%
	Essential Energy	$6,099	5.1%	1.0	3.2%
QLD*	Energex	$7,011	11.5%	1.2	4.4%
VIC	CitiPower	$1,190	9.8%	0.3	0.9%
	Powercor	$2,512	7.7%	0.3	1.0%
	Jemena	$994	2.2%	0.1	0.3%
	SP AusNet	$2,446	7.8%	0.3	1.0%
	United Energy	$1,675	5.7%	0.2	0.6%

Source: Unpublished AER analysis; AEMC analysis. *Figures for Ergon Energy were not available.

With respect to the impact on an average customer's bill, Table A.2 shows that the complete removal of demand related capex is estimated to decrease costs by between 0.1c/Kwh and 1.2c/Kwh or between 0.3 per cent and 4.4 per cent. Modelling also

62 If peak demand is above forecast demand and a network business chooses not to invest to upgrade capacity, it may breach its regulated state reliability requirements.

63 Growth related' capital expenditure in this context includes expenditure associated with both augmentation and new connections.

shows that a 20 per cent difference between actual and forecast demand only represents up to around 0.75 per cent of consumer retail prices, and substantially less in some jurisdictions.

Such evidence suggests that even though demand related capex is a substantial contributor to the value of the RAB, it has only a relatively small effect on costs in the period in which its allowance is included in revenues; and hence on consumer prices. This is because, while the capex is spent throughout the regulatory control period, it is recovered over the lives of the assets and so extends well beyond the regulatory control period to which that growth capex relates.

A.2 The nature of electricity demand

Electricity is generally measured as energy, average demand or peak demand. Energy is the volume of electricity transported on the network or section of the network over a defined time. Average demand represents the average load on the network and peak demand is the maximum load. Energy is usually measured in megawatt hours (MWh) or gigawatt hours (GWh), while average and peak demand is commonly measured in megawatts (MW).

AEMO forecasts energy and peak demand at the jurisdictional level. To do this they define two distinct loads – large industrial and non-large industrial – that are measured separately as different factors underpin their growth.[64] Large industrial loads are generally connected to the transmission network, with consumption that varies due to investment or decommissioning decisions for large industrial projects. Non-large industrial loads are those connected primarily to distribution networks, such as commercial and residential customers. This type of consumption is a function of a number of variables that are more difficult to forecast than large industrial loads, such as regional income, energy prices and weather.

Electricity supply is instantaneous and currently cannot be stored economically, which means supply must equal demand at all times. This allows AEMO to measure demand by metering output to the network from generators, not consumption from end users.[65] Under this methodology, an increase in small-scale embedded generation (such as residential solar PV) and energy efficiency acts to reduce the amount of electricity that needs to be supplied by large-scale generation and delivered through networks. AEMO accounts for these factors by estimating the contribution from solar PV and energy efficiency and subtracting these from forecast demand.[66]

Transmission and distribution networks also forecast energy and peak demand for regulatory determinations and operational purposes. Ausgrid undertook spatial and global forecasts for its 2009-14 determination.[67] Seven to ten year spatial forecasts at each zone and sub-transmission substation were used to identify locations where expected growth in peak demand was likely to require transmission network

64 AEMO 2012, National Electricity Forecasting Report, p. 2-6.

65 AEMO 2012, *National Electricity Forecasting Report*, p. 2-6.

66 Id., p. 2-7.

67 EnergyAustralia 2008, *Regulatory proposal*, p. 42.

augmentation. For distribution, global (whole of network) forecasts were carried out using statistical techniques that accounted for appliance mix and customer type.

A.2.1 What is happening to actual demand versus forecast demand?

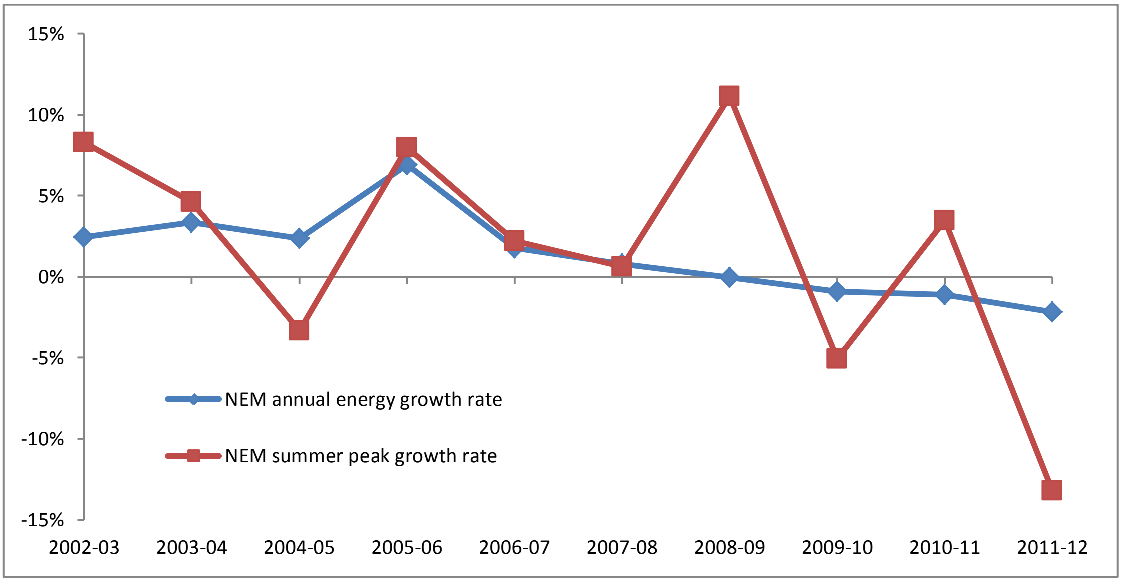
Forecasts of energy and peak demand partly drive NSP allowed revenues through the link with augmentation capex. Changes in outturn and forecast demand will affect NSPs and consumers differently depending on the form of control applied by the AER. If demand forecasting is becoming more difficult, this may have implications for how NSPs and consumers continue to share the risks inherent in incentive based regulation.

The following analysis will examine how energy and peak demand growth has changed over time and whether demand forecasting is becoming more difficult.

Annual energy and peak demand in the NEM

Growth in annual energy across the NEM has been falling since 2005-06 and has been negative since 2008-09, as shown in Figure A.4. Summer peak demand has been more variable over the same period, with negative growth occurring in 2004-05, 2009-10 and 2011-12. Preliminary AER data for 2012-13 shows summer peak demand has rebounded to around five per cent.[68]

Figure A.4 NEM annual energy and summer peak demand growth rates[69]



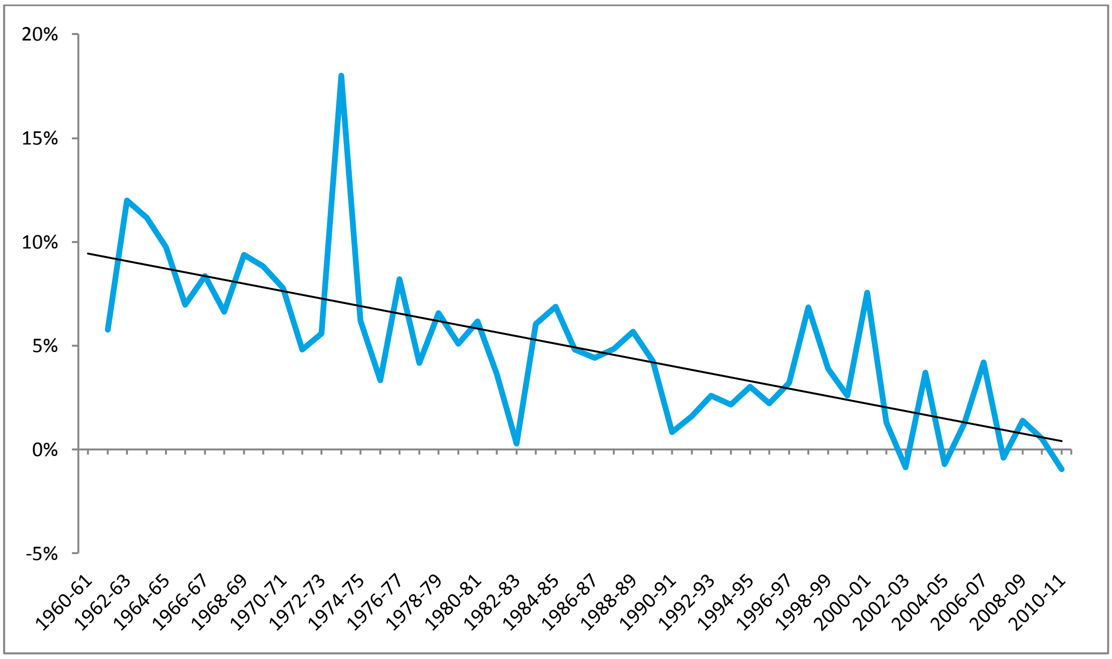
Source: AER performance of the energy market data, AEMC analysis.

The long term trend of annual energy growth in the Eastern states is clearly decreasing, as shown in Figure A.5, although there is a high degree of volatility between the years. Financial year 2002-03 saw the first 12 month period of negative growth in annual energy, which was followed by negative growth years in 2004-05, 2007-08 and 2010-11.

68 AER 2013, *Performance of the energy sector, seasonal peak demand.*

69 Tasmania joined the NEM in 2005, which inflates the annual energy growth rate for 2005-06.

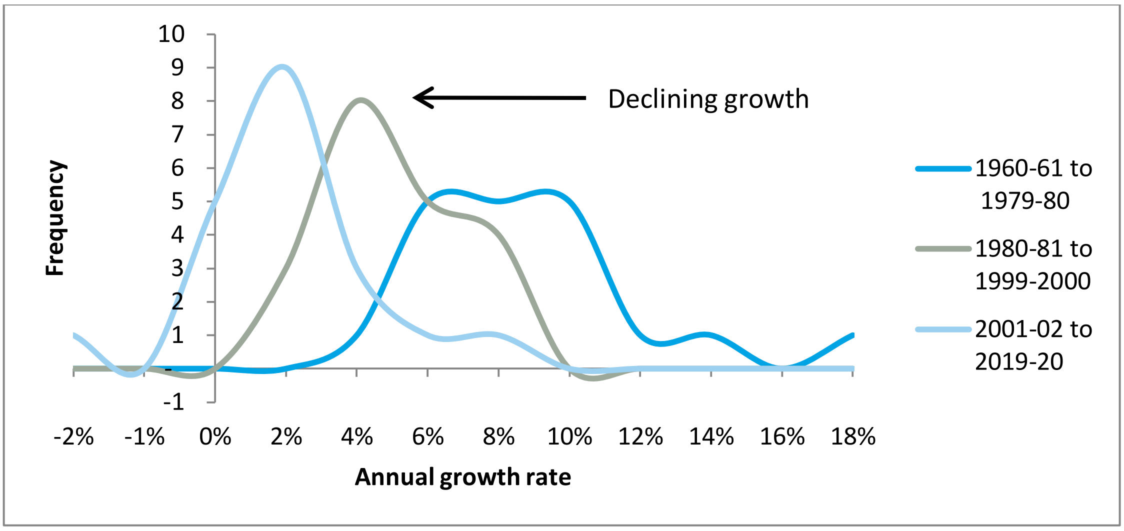
Figure A.5 Eastern states annual energy growth rate 1960-61 to 2010-11 (with trend line)[70]



Source: BREE 2012, Table I, AEMC analysis.

Figure A.6 is a graph of 20 year distributions of annual energy growth observations. It shows that, over time, growth rates have decreased, with higher growth occurring more regularly between 1960 and 1980 before decreasing in subsequent decades.[71] We note that while this graph highlights the long term trend, it hides the yearly volatility of demand growth (as seen in Figure A.5) that the network regulatory frameworks and network businesses must deal with.

Figure A.6 Two-decade distributions of NEM annual energy growth



Source: BREE 2012, Table I, AEMC analysis.

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70 Includes NEM and off-grid consumption.

71 The 2001 to 2020 distribution uses actual data up to 2011-12 and forecast data from AEMO's Medium scenario out to 2019-20.

Investment in transmission and distribution network infrastructure is primarily driven by regional and local economic factors. As these are often quite different between (and within) each state, it is important to analyse energy and peak demand at the jurisdictional level. The Commission notes that demand growth varies considerably within each jurisdiction and even within networks. However, publically available demand data below the jurisdictional level is not currently available.

The following section examines energy and peak demand forecasts over the previous decade for each region in the NEM. Data for the following charts has been sourced from AEMO's publically available Electricity Statement of Opportunities (ESOO) and National Electricity Forecasting Report (NEFR) publications.[72] Annual energy forecasts are representative of AEMO's Medium scenario, while peak demand forecasts use AEMO's Medium 50 per cent probability of exceedence (POE) scenario.[73]

AEMO uses demand forecasts for operating the NEM, calculating marginal loss factors and as an input for transmission planning.[74] We note that NSPs produce and utilise their own forecasts at a greater level of detail than AEMO's for the purpose of managing their networks. Nonetheless, the publicly available AEMO data is a useful proxy for understanding changes in demand and whether demand forecasting is becoming more difficult for market participants.

The Commission emphasises that the purpose of this analysis is to understand how energy and peak demand has changed over time and whether demand forecasting is becoming more challenging. If this is the case, it will be beneficial to understand and debate the reasons why. The Commission acknowledges that demand forecasting is inherently uncertain and does not consider that any single organisation's forecasts are more or less accurate than others.

Due to this uncertainty, we consider that a wide range of forecasts, undertaken by multiple stakeholders, best supports achievement of the NEO. When submitting a regulatory determination, NSPs are required to present their best demand forecasts to the AER. The AER should then have access to a range of forecasts from different sources to test the proposals from the NSPs. This recognises that no party is likely to have all the insights relevant for demand forecasting.

A.2.2 Annual energy and peak demand across jurisdictions

Queensland

Annual energy and peak demand for Queensland is shown in Figure A.7a and Figure A.7b. Annual energy increased up to 2009-10, before declining in the following year and picking up again in 2011-12. Summer peak demand had been mostly rising out to 2009-10, before falling for two consecutive years.

72 Prior to 2012, AEMO developed demand forecasts for South Australia and Victoria, while the regional TNSPs developed the Queensland, New South Wales (including the Australian Capital Territory) and Tasmanian forecasts, which were published by AEMO in the ESOO. AEMO now develops and publishes its own demand forecasts for all NEM regions in the National Electricity Forecasting Report.

73 A 50 per cent POE is expected to be exceeded on average one year in two.

74 AEMO 2012, *National Electricity Forecasting Report*, p. 1-1.

Forecasts appear to have underestimated energy and peak demand growth up to around 2004-05 and overestimated growth since around 2006-07.

Figure A.7a Queensland annual energy forecasts and actual data (GWh)

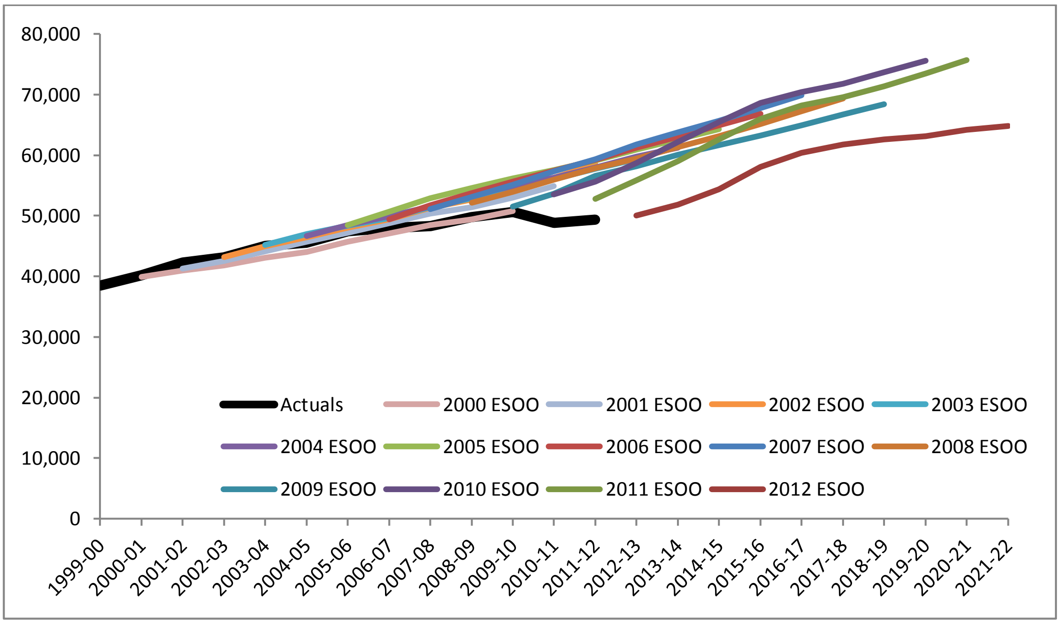
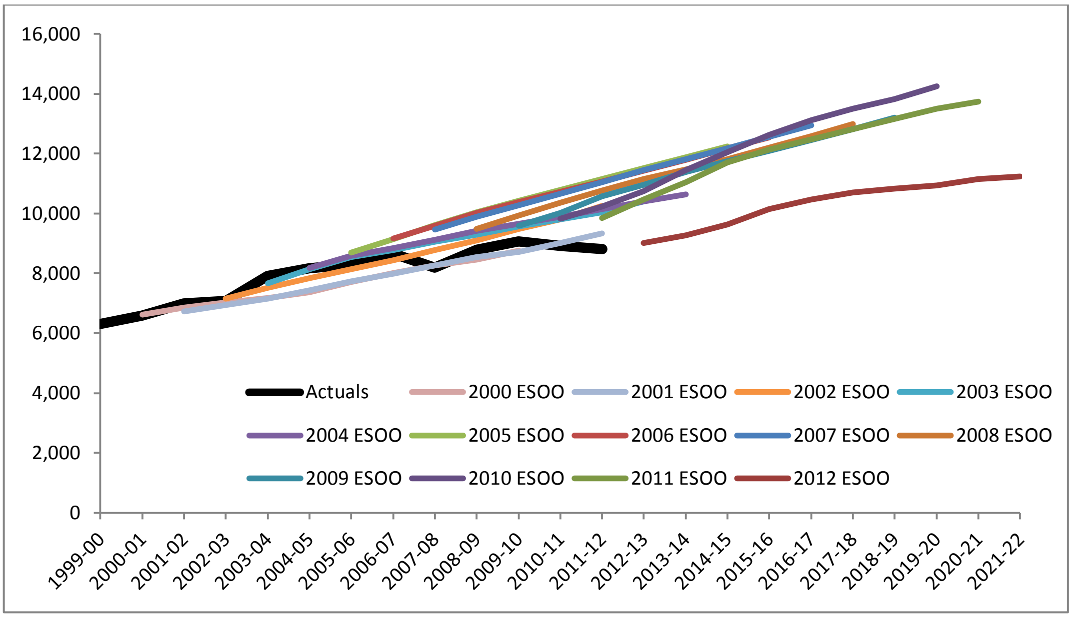


Figure A.7b Queensland summer peak demand forecasts and actual data (MW)



New South Wales

Figure A.8a and Figure A.8b show New South Wales annual energy and peak demand growth. Annual energy grew consistently up to 2007-08, before entering consecutive periods of decline to 2011-12. The forecasts appear relatively accurate up to the point when growth began moderating. The 2012 forecast was decreased notably, consistent with the on-going drop in energy consumption.

Summer peak demand growth in New South Wales has been relatively volatile over the past decade, including the sharp drop from 2010-11 to 2011-12.[75] Forecasts underestimated peak demand up to around 2005-06 and have been overestimating in recent times.

Figure A.8a New South Wales annual energy forecasts and actual data (GWh)

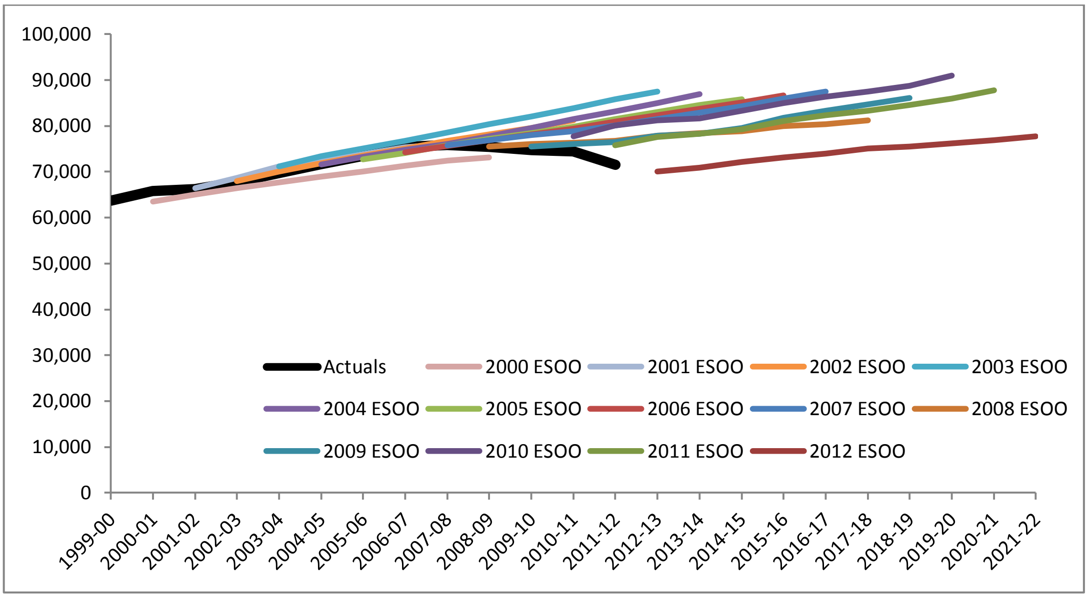
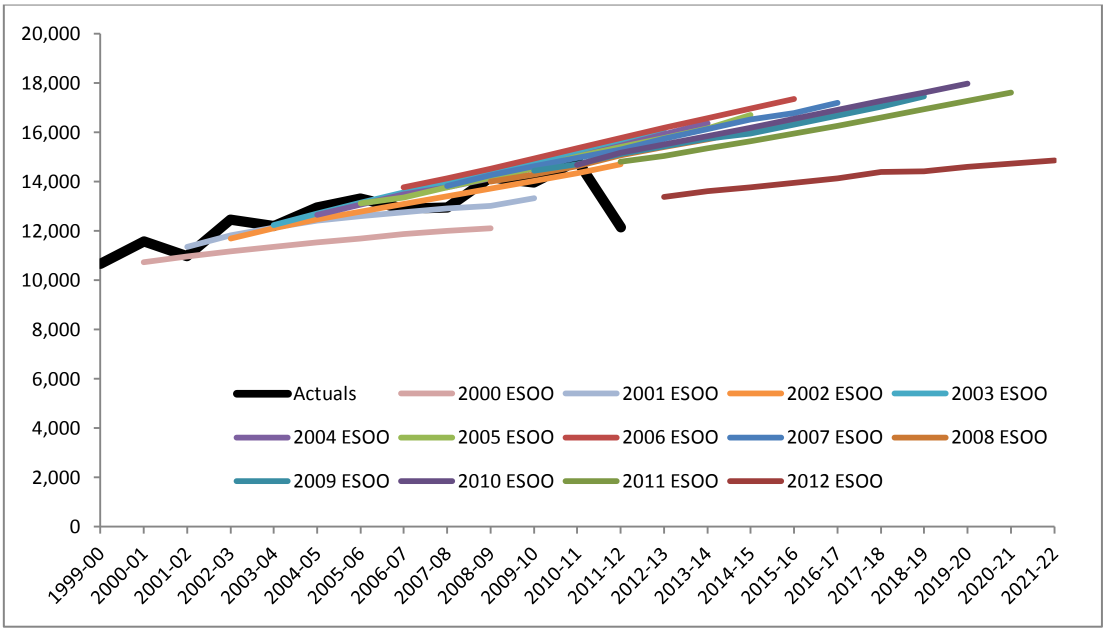


Figure A.8b New South Wales summer peak demand forecasts and actual data (MW)



75 Preliminary AER data indicates that the 2012-13 summer peak demand has rebounded to 13,781 MW.

Victoria

Victorian annual energy demand peaked in 2007-08 and is currently at a level last seen in 2005-06. Energy forecasts appear to have been relatively accurate over the last decade, aside from the 2008 ESOO, which was influenced by changes to the Mandatory Renewable Energy Target and the treatment of wind generation as non-scheduled before the current semi-scheduled category was created.

Peak summer demand increased up to 2008-09 before starting a decline that has seen it fall back to 2006-07 levels. While the peak demand forecasts have been revised downward over the last few years, they have been unable to account for the trend or magnitude of decline.

Figure A.9a Victorian annual energy projections and actual energy demand (GWh)

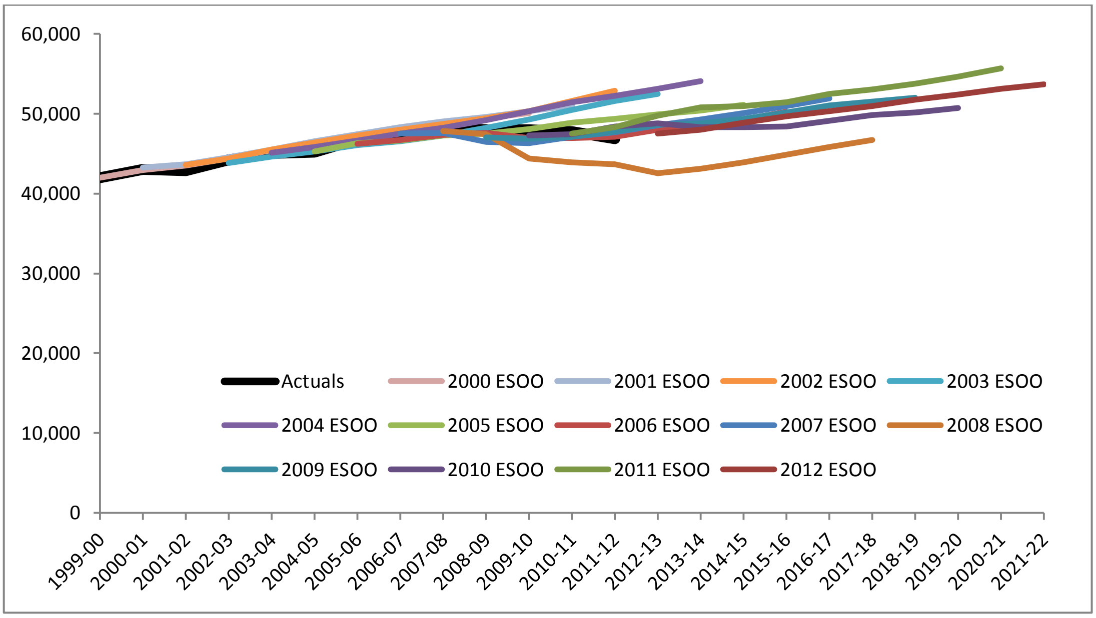
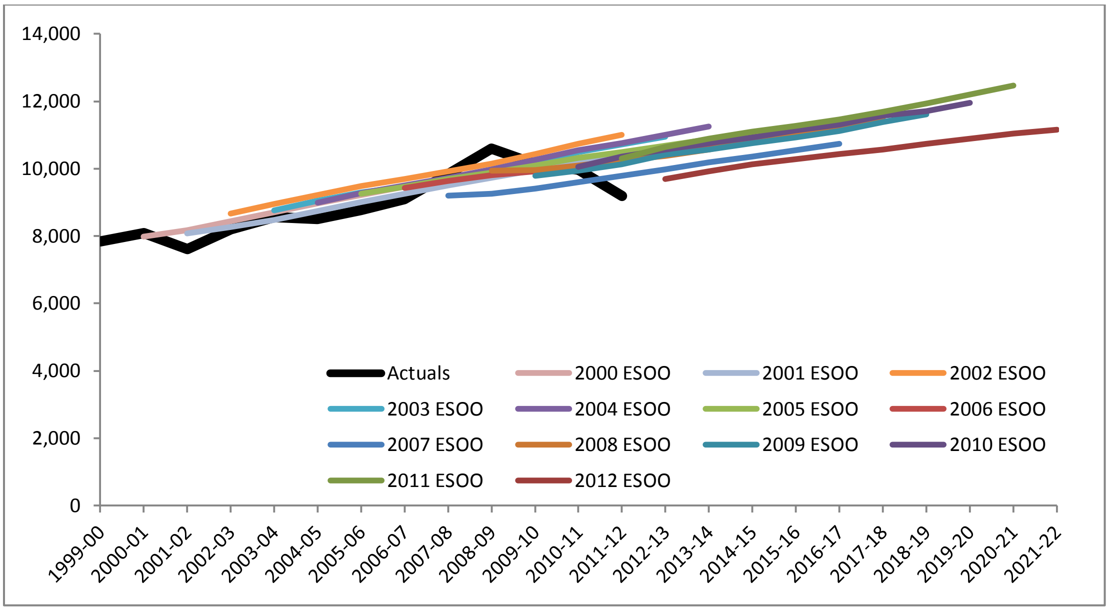


Figure A.9b Victorian summer peak demand forecasts and actual data (MW)



South Australia

South Australia's annual energy growth is more variable compared to other jurisdictions. Between 1999-00 and 2011-12 there were five instances of negative growth and two years of growth under one per cent. There was also three years of growth above four per cent, including one year of over five per cent. This appears to have made forecasting challenging as forecasts have over- and underestimated actual energy at various times since 2000, as shown in Figure A.10a.

Figure A.10b illustrates the growth in summer peak demand, which suffered the biggest annual drop in this data series between 2010-11 and 2011-12. Forecasting looks to be more difficult than in other states due to the variability in peak demand growth, having both under- and overestimated actual demand at times.

Figure A.10a South Australia annual energy forecasts and actual data (GWh)

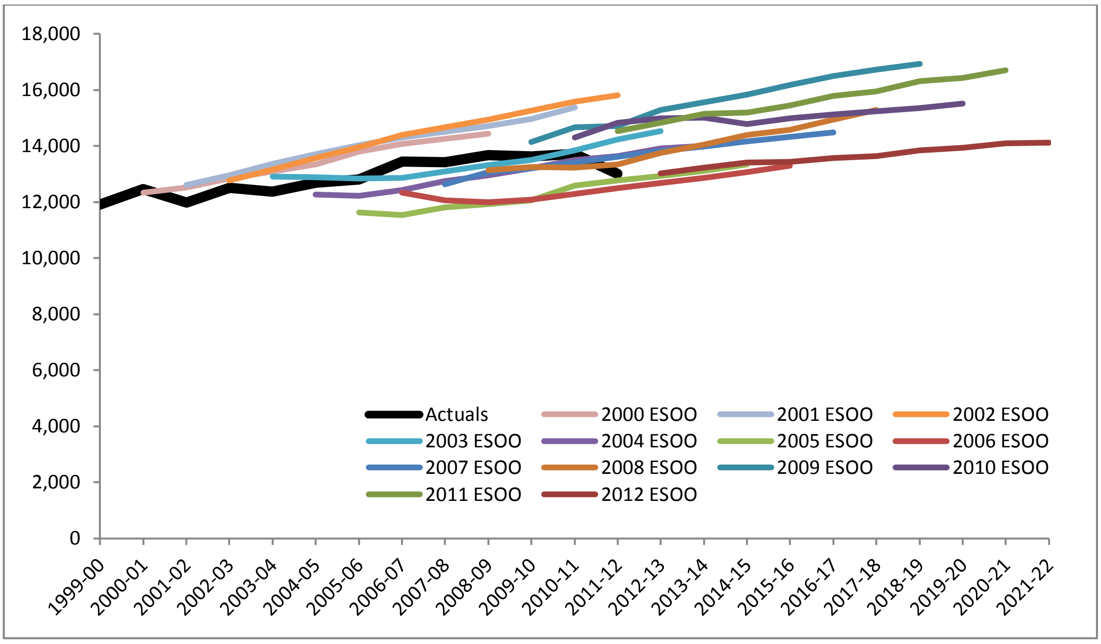
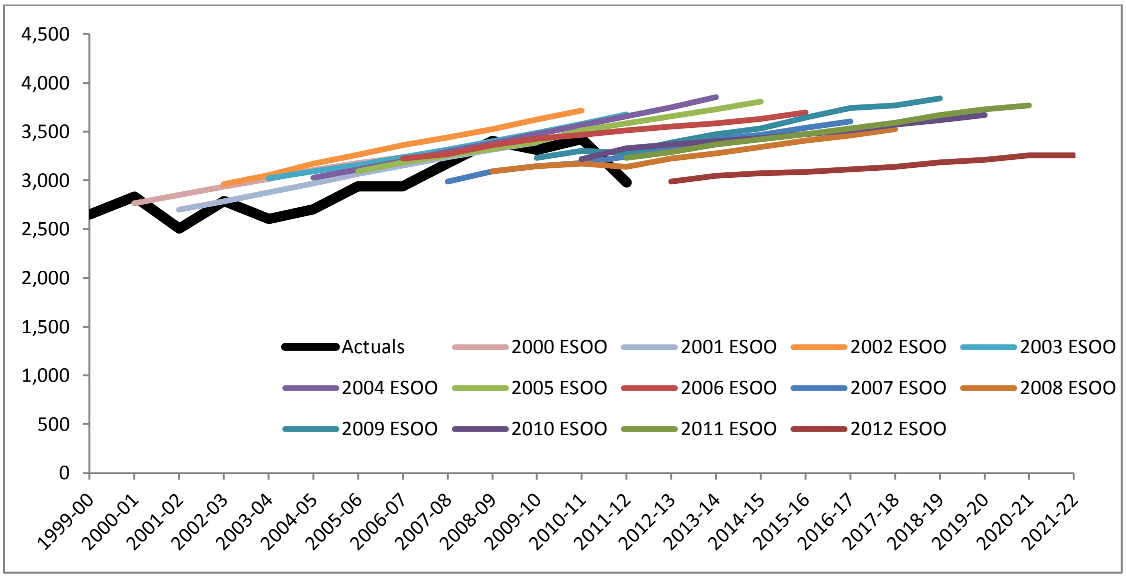


Figure A.10b South Australian summer peak demand forecasts and actual data (MW)



Tasmania

Figure 11a and Figure 11b show Tasmanian energy and peak demand growth. Energy growth has been relatively flat, fluctuating between 9,677 GWh and 10,979 GWh. Peak demand grew inconsistently up to 2008-09, before starting a decline. Since 1999-00, Tasmanian peak demand has fluctuated between the relatively narrow band of 1,281 MW and 1,487 MW.

Energy forecasts appear to be relatively close to actual energy, while peak demand forecasts have both understated and overestimated summer peak to varying degrees.[76]

Figure A.11a Tasmanian annual energy forecasts and actual data (GWh)

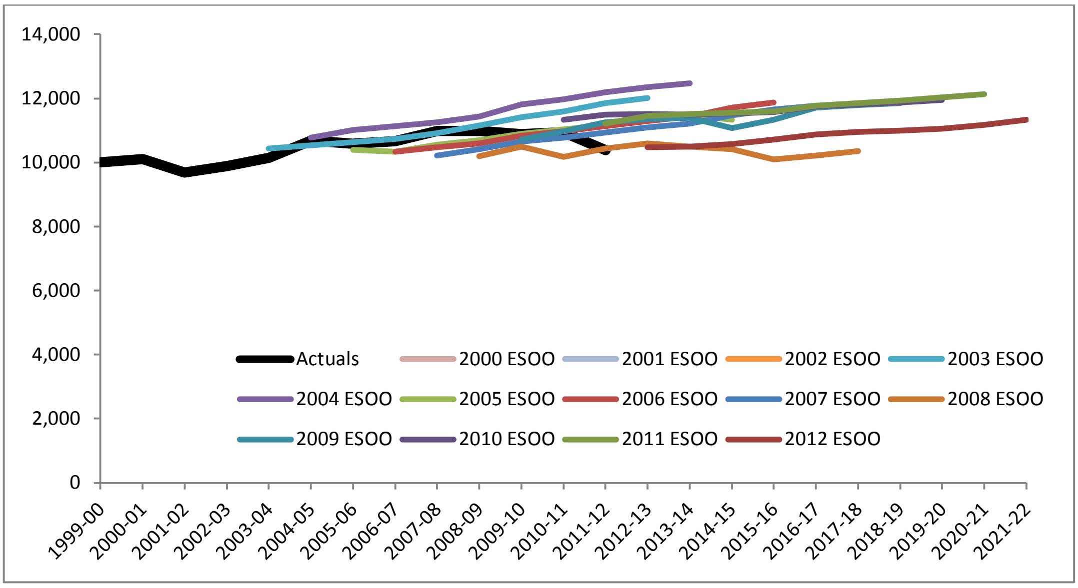
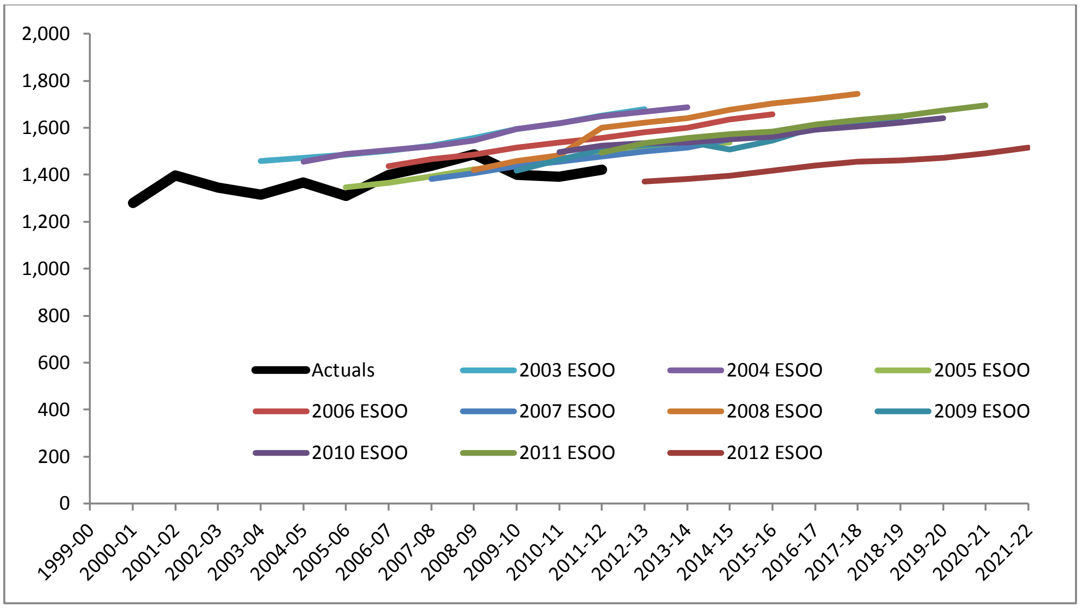


Figure A.11b Tasmanian summer peak demand forecasts and actual data (MW)



76 AEMO started forecasting the Tasmanian region in the ESOO in 2003.

A.2.3 Is demand becoming more difficult to forecast?

For Queensland, New South Wales and Victoria, the above analysis suggests that energy and peak demand is becoming more difficult to forecast. The breakdown has mostly occurred from around 2007-08, when demand started to decline and the forecasts look to have been unable to predict the timing or magnitude of the turn. Forecasting for South Australia and Tasmania, on the basis of this data, appears to have been historically more challenging than for the other states. This is most likely due to the higher degree of variability in annual growth rates.

One likely reason why demand forecasting has been unable to predict the drop in demand is due to the uptake of solar PV and energy efficiency measures, both of which were stimulated by government policies. However, it is difficult to measure precisely the extent to which the recent changes in demand are due to solar PV and energy efficiency, the current economic cycle, structural economic factors, weather or government incentives.

The section discusses some of the recent challenges in forecasting demand and how it may become more challenging or potentially easier due to the implementation of smart technologies.

Solar PV and energy efficiency

AEMO considers that the increase uptake of residential solar PV may be contributing to the decrease in demand for large-scale generation.[77] As noted above, the outcome of rising solar PV use is that, even if energy consumption is constant, there is less demand for network delivered energy, which in turn reduces network utilisation.

Evidence is emerging that improvements in the energy efficiency standards of new housing may be contributing to reductions in demand. Analysis by SP AusNet shows a materially lower electricity consumption profile for housing built in the past two or three years compared to houses built more than ten years ago. [78] Similarly to solar PV, measures taken by households and businesses to increase energy efficiency, such as through insulation, installing more efficient lighting or investing in more efficient equipment/appliances, will reduce network delivered electricity.

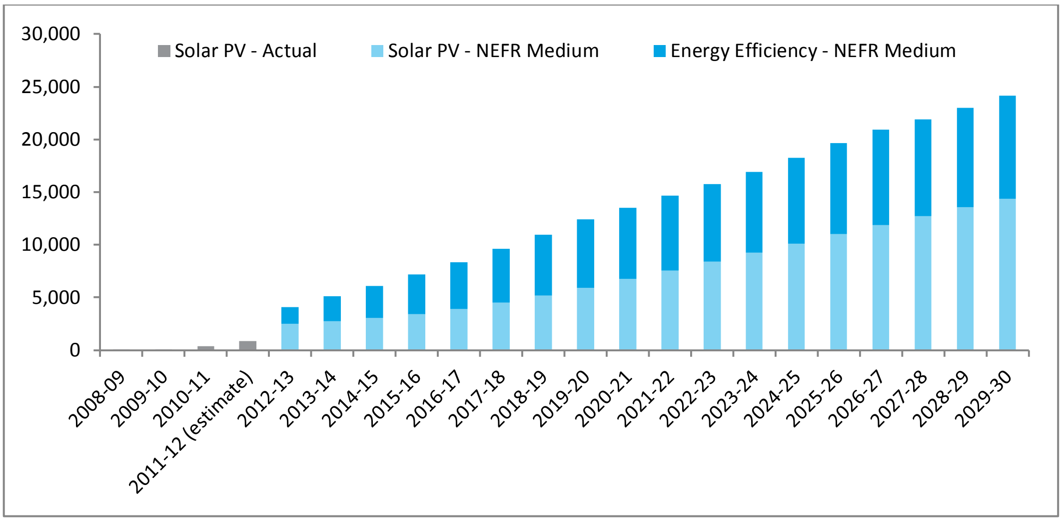
AEMO has begun forecasting the contribution of solar PV and energy efficiency due to the importance of these factors in meeting demand. Figure A.12 compares AEMO's estimate of the current level of residential solar PV output with its forecasts of solar PV and energy efficiency. Over the next twenty years, solar PV and energy efficiency is expected to offset the amount of large-scale grid connected generation by around 25,000 GWh by 2030. This is equivalent to around 16 per cent of 2011-12 non large industrial NEM consumption.

We note that a driver of solar PV and energy efficiency in recent times has been government initiatives and incentives. As these usually cannot be anticipated well in advance and are subject to change, there is a degree of uncertainty as to whether recent trends will continue. With solar PV and energy efficiency now part of AEMO's demand forecasting equation, this uncertainty adds to the inherent difficulty in forecasting annual energy and peak demand.

77 AEMO 2012, *National electricity forecasting report*, June 2012, p.v.

78 This analysis is contained in SP AusNet's 2013-17 Gas Access Arrangement Review.

Figure A.12 AEMO forecasts of solar PV and energy efficiency for the NEM (GWh)



Source: AEMO 2012, *National Electricity Forecasting Report*.

Macroeconomic factors

Changes to the Australian economy directly affect electricity consumption. As economic output rises and falls, so does demand for electricity. However, the changing structure of the economy also has implications for energy growth.

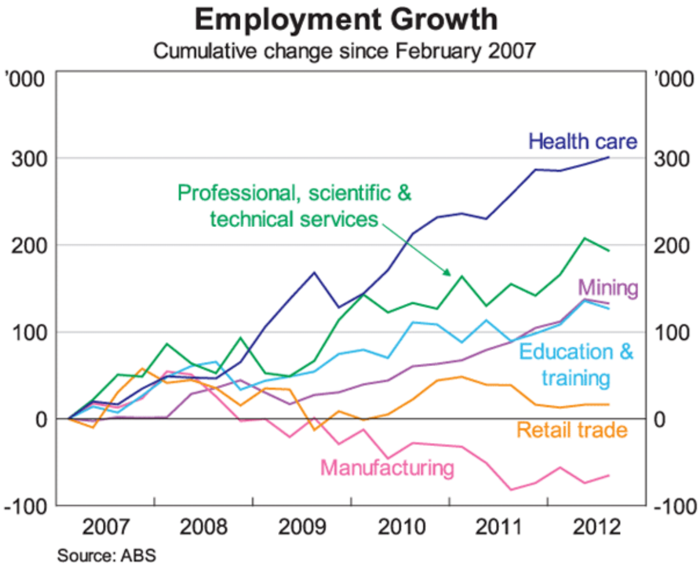
The Australian economy is gradually moving away from its agricultural and manufacturing origins to one based on services.[79] This is illustrated in Figure A.13, where employment growth in services-based industries has been outstripping jobs in the manufacturing industries (such as aluminium smelting) since around 2008. These changes also reflected in the decreasing energy intensity of the Australian economy, as services-based industries use less energy per unit of output relative to manufacturing.[80]

When forecasting peak and energy demand, AEMO, NSPs and other organisations have the challenging task of estimating not just the level of economic growth, but also the structural changes underway in the economy and macroeconomic influences (such as the high Australian dollar), and how these might affect demand.

79 RBA 2010, *Structural change in the Australian economy*, the Bulletin, September quarter.

80 BREE 2012, *Energy in Australia*, p. 21.

Figure A.13 Australian employment growth, by industry



Source: Reserve Bank of Australia 2012, *The labour market, structural change and recent economic developments*, by Deputy Governor Philip Lowe, October.

Demand-side participation and smart meters

Greater utilisation of demand-side participation (DSP), not unlike the uptake of solar PV, will act to reduce demand for large-scale network delivered generation and increase the challenges around forecasting peak demand. This is because the growth in DSP utilisation is uncertain and will need to be independently forecast. Conversely, a widespread roll out of smart meters will provide more accurate and timely consumption data, allowing AEMO and NSPs to establish correlations between demand and other variables, such as solar PV and DSP, over time.

Weather

Weather can have a significant impact on the delivery of electricity. Changes in temperature create major spikes in electricity use due to the demand for heating and cooling.

Australian homes with an air-conditioner or evaporative cooler have risen from around 40 per cent in 2000 to over 70 per cent in 2011.[81] In South Australia, the penetration of air-conditioners is 90 per cent of all houses, most with multiple units. The rapid uptake of air-conditioners is a principle driver of peak demand and network augmentation investment.[82]

The close relationship between temperature and peak demand helps explain the volatility in peak demand growth seen across jurisdictions in the above analysis. If the eastern states of Australia have a relatively mild summer compared with previous ones, summer peak demand growth will decline and vice versa. Temperature has always been, and is likely to always be, a central factor and key uncertainty when forecasting peak demand.

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81 Topp, V. and Kulys, T. 2012, *Productivity in Electricity, Gas and Water: Measurement and Interpretation*, Productivity Commission Staff Working Paper, p. 45.

82 Ernst & Young 2011, *Rationale and drivers for DSP in the electricity market – demand and supply of electricity*, p. 41.

B Explanation of the current rules

This Appendix discusses how the current provisions in the NER that the deal with:

- the role of demand forecasts in network determinations where costs for a regulatory control period are approved using expenditure forecasts at the time of the determination;
- how NSPs are allowed to recover their revenues within a regulatory control period; and
- what happens when actual demand falls during a regulatory control period where network investment decisions are made based on forecast demand.

B.1 Impact of differences between forecast and actual demand on investment

Summary

The incentive arrangements reflected in the NER are intended to provide NSPs with sufficient incentives to reduce expenditure below the capex allowance where possible, including where peak demand forecasts are revised downwards from those adopted at the time of the regulatory determination. Some of these incentive arrangements are hard-wired into the NER (such as the roll-forward of the RAB on the basis of actual capex, provided that expenditure is within the earlier forecast). However the NER also provides the AER with the ability to develop the overall capital incentive expenditure approach. The AER is currently in the process of developing its approach, following the changes made to the NER in November 2012.

Under the current NER, consumers benefit from reductions in expenditure when demand falls below forecasts, as the actual (lower) amount of capex is rolled into the RAB and reflected in prices at the time of the next review, rather than the higher capex level initially forecast.

Where peak demand increases above the level forecast at the time of the determination, the current NER continue to provide incentives for NSPs to try to accommodate that increase within the capex allowance set. However, where this is not possible (due to the magnitude of the additional capex required), the NSP is subject to a penalty for any overspend. This penalty is necessary in order to retain the symmetry of incentives under the NER. However the full amount of the required capex (subject to any prudency review) is rolled into the RAB, and reflected in consumer prices, from the start of the next regulatory control period.

The uncertainty mechanisms in the NER could also be used, to differing extents, to address uncertainty in relation to future demand forecasts.

- The contingent project mechanism in the NER provides a potential mechanism to manage the uncertain impact on the need and timing of specific network investments arising from material differences between actual and forecast demand, and may enable more conservative demand forecasts to be adopted at the time of the determination.

- The capex re-opening provisions in the NER could also be used to address the impact of a greater than anticipated increase in demand that necessitated a substantially higher level of capex. However the threshold for the use of the re-opening provisions is set such that they are triggered only as a last resort, in response to significant external changes, and only for increases in expenditure.
- It would also be open to NSPs to propose a cost pass through event to cover a 'demand forecasting event', although such an event would need to be approved by the AER, having regard to the nominated cost pass through considerations in the NER.

The requirement in the NER to apply the relevant regulatory investment test (ie, the RIT-T or RIT-D) represents a further point at which the need for a specific network investment is assessed and subject to public consultation, based on the most recent forecasts of future demand available at the time the test is applied.

There are currently only limited provisions in the NER for adjustment of an NSP's regulatory asset base to account for the degree of utilization of previously approved capex. The AEMC recently reviewed the appropriateness of expanding these optimisation provisions, in response to a rule change proposal by the MEU, and concluded that introducing such a provision would increase the risk to service providers and provide disincentives for future investment.

Proposed revisions to the Demand Management and Embedded Generator Incentive Scheme (DMEGCIS) following from the AEMC's *Power of Choice Review* may result in more effective encouragement of demand management as an alternative to network augmentation.

Allowed revenue at the time of a regulatory determination is set on the basis of a forward-looking assessment by the AER of the efficient level of expenditure over the forthcoming regulatory control period, both capex and operating expenditure. The assessment of capex in particular will be heavily dependent on forecast demand, and in particular forecasts of expected peak demand over the period.

Differences between forecast and outturn demand can occur within a regulatory control period, which may also lead to revisions to future demand forecasts, based on actual outturns.

The following sections discuss the current provisions in the NER, focusing on the incentive arrangements applying to capex and the various 'uncertainty mechanisms' available to manage the cost impacts of changes in external factors. In particular, this section discusses the implications of the current arrangements on the incentives for NSPs to undertake an efficient level of investment, in circumstances where there demand forecasts change during the regulatory control period. Given that investment is related to forecast demand (and in particular peak demand), rather than actual outturn demand, the focus on the discussion in this section is on changes in demand forecasts, albeit that such changes are typically driven to a large extent by differences between forecast and outturn demand.

B.1.1 Expenditure forecasts reflect cost to meet forecast demand

Forecasts of expected future peak demand are a key driver for network investment.[83] In particular, the expected future level of peak demand (which is measured in MW) is a key factor in determining the need to augment the existing transmission and distribution networks, in order to ensure that required network reliability standards continue to be met.

The level of capex expected to be required over a regulatory control period is therefore heavily dependent on the expected growth in future peak demand.[84]

One of the capex objectives set out in the NER is that the TNSP's proposed expenditure should reflect the expenditure it considers is required in order to "meet or manage the expected demand for prescribed transmission services over [the regulatory] period".[85]

A similar capex objective applies to DNSPs, under NER 6.5.7(a)(1).

Under clause 6A.6.7(c):

> "The AER must accept the forecast of required capital expenditure of a Transmission Network Service Provider [TNSP] that it included in a Revenue Proposal, if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects:
>
> …
>
> (3) *a realistic expectation of the demand forecast* and cost inputs required to achieve the *capital expenditure objectives.*"

Again, a similar reference applies to the capex forecasts submitted by DNSPs, under 6.5.7(c)

In addition, similar references to the NSP's proposed expenditure needing to reflect 'a realistic expectation of the demand forecast' applies under clause 6A.6.6 (c) and 6.5.6 (c) to acceptance of the NSP's operating expenditure forecast.

B.1.2 Incentive provisions in the NER

Forecasts of peak demand may change over the regulatory control period, compared with those assumed at the time of the regulatory determination. The efficient level of demand-driven capex required to be undertaken by the NSP may therefore also differ from that which was reflected in the capex forecast at the time of the regulatory determination.

Under the NER, there are a number of provisions which are intended to provide the NSP with the incentive to undertake an efficient level of investment based on the latest

83 Forecasts of the total energy demanded (MWh) are also important in that they affect decisions on the level of prices that are expected to recover the NSP's total allowed revenue. This is discussed further in sections B.2 and B.3 of this chapter.

84 The assessment of whether network augmentation is required in order to continue to meet reliability standards is a forward-looking assessment, and is therefore based on forecasts of future peak demand, rather than actual outturn peak demand (although changes in outturn peak demand can be expected to be a key factor underlying changes in forecast peak demand).

85 NER clause 6A.6.7(a)(1).

demand forecasts at the time the investment decision is made, regardless of the capex allowance (and demand forecast) at the time of the regulatory determination. There have been a number of recent changes to the NER in this area, made in response to the AER's rule change proposal.[86] The issue of the appropriate incentives for efficient capex was considered in detail as part of the process associated with this rule change, and the resulting changes to the NER introduced an explicit "capital expenditure incentive objective", as well as expanding the range of options open to the AER to provide appropriate incentives.

The capital expenditure incentive objective set out in the NER[87] is to ensure that where the value of a RAB is subject to adjustment in accordance with the NER, then the only capex that is included in an adjustment that increases the value of that regulatory asset base is capex that reasonably reflects the capex criteria.

Under the current NER (which reflect the recent changes in response to the *Economic Regulation of Network Service Providers* Rule Determination):

- the actual capex undertaken by the NSP over the regulatory control period is rolled into its RAB at the time of the next regulatory determination.[88] This may be higher or lower than the level of investment underpinning the capex allowance at the time of the earlier regulatory determination;

- prior to rolling in actual capex, the AER has the option of undertaking a review of the efficiency and prudency of that investment, where the total capex in the regulatory control period exceeds the capex forecast at the time of the determination, and where the AER's Capital Expenditure Incentive Guidelines have incorporated the possibility of such an ex post review.[89] Any such review undertaken by the AER needs to be consistent with principles set out in the NER, which include the need to provide incentives to the NSP to avoid undertaking inefficient capex;[90]

- the AER is required to develop Capital Expenditure Incentive Guidelines,[91] which sets out how its approach adopted to various aspects of the treatment of capex meets the capital expenditure incentive objective set out under the NER. Such incentive arrangements may incorporate the roll-forward of the RAB on the basis of actual or forecast depreciation (where the former provides a stronger incentive for efficient expenditure) and the introduction of a specific capex incentive scheme (termed a "capital expenditure sharing scheme"). The NER sets out principles with which any capital expenditure sharing scheme needs to comply;[92] and

86 See http://www.aemc.gov.au/electricity/rule-changes/completed/economic-regulation-of-network-service-providers-.html

87 NER rules 6A.5A(a) and 6.4A(a).

88 NER clauses S6A.A(f) and S6.2.1(e).

89 NER clauses S6A.2.2A and S6.2.2A.

90 NER clauses 6A.2.2(6) and S6.2.2(6).

91 NER rules 6A.5A(b) and 6.4A(b).

92 NER clauses 6A.6.5A and 6.5.8A.

- the AER is required to review the efficiency of all past capex for all NSPs as part of the determination process and include a statement (with supporting reasons) as to the extent that the expenditure being rolled into the RAB is consistent with the capital expenditure incentive objective (ie, is prudent and efficient).[93]

The following section discusses the implications of the above incentive mechanisms for efficient investment in a situation where forecast demand changes over the regulatory control period.

In addition, the NER also contains provisions:

- requiring the majority of network investment to be subject to an additional network investment test, including investment undertaken in order to ensure network reliability standards continue to be met where peak demand is increasing. This network investment test includes the need to consider non-network (including demand management) alternatives to network investment; and
- aimed at ensuring that DNSPs have incentives to undertake demand-management (in particular the DMEGCIS), including where the resulting reductions in a demand would otherwise reduce the revenue which the DNSP would earn.

These provisions are discussed in sections B.1.5 and B.1.7.

Implications of current NER provisions where demand forecasts changes

In the context of changes in peak demand forecasts (and/or actual peak demand) over the regulatory control period, compared with that forecast at the time of the determination, the incentive mechanisms discussed above would operate in the following way .

Reductions in forecast peak demand

If forecasts of peak demand fall during the regulatory control period, below the level assumed at the time of the regulatory determination, the NSP may be able to reduce or defer the amount of investment needed in order to ensure that the required reliability standards continue to be met, with the result that it will spend less than the capex allowance. The extent to which the NSP considers it is able to reduce or defer its expenditure will depend on whether it expects the lower level of demand forecast to be maintained, and its overall approach to managing the risk of failing to meet its reliability obligations (which may result in a more conservative approach being adopted in relation to reductions in expenditure).

The NSP has an incentive to underspend its capex allowance (ie, to spend only the efficient level of capex implied by the lower peak demand forecast), since the incentive mechanisms in the NER result in it being rewarded for reductions in expenditure below the capex allowance. This incentive applies equally where the NSP may be undertake demand management (or another non-network option) in order to enable the network to accommodate the lower peak demand forecast, and the associated

93 NER clauses 6A.14.2(b) and 6.12.2(b).

expenditure is less than the network expenditure allowed at the time of the determination. A reduction in peak demand may mean that demand management options become feasible alternatives to network investment.

Under the recently revised NER provisions, the strength of the NSP incentive to underspend its capex allowance will depend on the specific capital incentive arrangements adopted by the AER. However, where the NSP underspends against its allowance it will at least gain the return associated with the amount of the underspend for the remainder of the regulatory control period,[94] as well as possibly the depreciation associated with the underspend[95] and any additional reward under a specific capital expenditure sharing scheme.

The lower level of capex undertaken by the NSP will then be incorporated into the NSP's RAB at the time of the next reset, meaning that customers only pay for the (lower) level of investment associated with the reduction in peak demand, from the start of the next regulatory control period. As a consequence, NSPs benefit from the reduction in demand forecasts during the regulatory control period, with this benefit then being passed through to customers in the following regulatory control period,[96] in the form of lower prices reflecting the lower actual level of investment incurred.

In addition to the incentives for the NSP to underspend its capex allowance, the recent changes to the NER have introduced the ability for the AER to review the prudency of capex prior to rolling it into the RAB, where it chooses to do so, provided that the total level of actual capex exceeds the capex allowance at the time of the regulatory determination. Where the NSP overspends its overall allowance, then the AER could review whether the actual capex incurred was efficient (ie, consistent with the capex criteria set out in the NER), including whether it was required given the lower level of either actual and/or forecast peak demand over the regulatory control period.

In a situation of falling peak demand forecasts, it appears more likely that inefficient investment would reflect a situation where the NSP continued to spend its full capex allowance, despite the lower peak demand forecast, but did not exceed this allowance. In this situation, the AER would not be able to disallow any of this expenditure, under the current NER, if the total capex allowance was not exceeded. The AEMC limited the scope for ex post review of capex to expenditure above the allowance in the recent changes to the NER relating to the Economic Regulation of Network Service Providers, on the basis that reliance on ex post review of all capex would weaken the ex ante incentive mechanisms, which provide incentives for efficiency and innovation in capex.[97] Finally, the regulatory investment test provisions in the NER may mean that prior to undertaking a specific investment, the NSP would have to re-assess the need

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94 That is, the WACC * capex component of the capital expenditure allowance, which is not subject to any 'clawback' at the end of the period if actual expenditure is below the forecast on which the capital expenditure allowance was based.

95 Where the AER determines that the RAB at the next determination should be rolled forward on the basis of depreciation based on the actual (lower) expenditure, rather than the amount of depreciation allowed at the time of the previous determination.

96 The speed with which the benefit would be passed through to customers will depend on the details of the capital expenditure sharing scheme adopted by the AER (if any).

97 AEMC, *Rule Determination – National Electricity Amendment Rule 2012*, 29 November 2012, p. 123.

for that investment, taking into account the lower peak demand forecast at the time of that re-assessment. The regulatory investment tests also require the NSPs to assess whether non-network options (including demand management), may represent a more efficient means of meeting expected future demand. The regulatory test provisions, and their interaction with the regulatory determination process, are discussed further in section B.1.5.

Increases in forecast peak demand

If forecast peak demand increases over the regulatory control period, above the level assumed at the time of the determination, then this may lead to a requirement for additional investment by the NSP, in order for the required network reliability standards to continue to be met.

The NSP may be able to be accommodate the additional investment by rearranging other investment priorities, and/or by undertaking demand management options, such that its total capex remains below the amount of the capex allowed by the AER in its determination. The NSP would have an incentive to try to remain below its overall allowance, as the incentive arrangements in the NER mean that it is penalized for any overspend of its allowance (see below). However, NSPs face a number of statutory and regulatory obligations, which may limit their ability to defer or reprioritize capex in the face of increasing peak demand.

Where it is not possible for the NSP to reprioritize other spending, it will end up spending more than the capex allowance included in the regulatory determination. Under the current incentive frameworks for capex in the NER, the NSP will be penalized for this overspend. The extent of this penalty will again depend on the AER's specific approach to capex incentives, but as a minimum will reflect the forgone return on any capex above the total allowance in the determination for the remainder of the regulatory control period.[98] It may also include the depreciation associated with that expenditure,[99] plus the penalty applied under any explicit capex sharing mechanism. The penalty associated with an overspend in relation to the capex allowance means that NSPs also have an incentive to adopt demand management alternatives, where these options have on average a lower annual cost than the annual allowance on the capex project within the regulatory control period.

The NSP's actual capex will be incorporated into its RAB at the time of the next regulatory determination, including the full amount of any additional capex (subject to the assessment of the efficiency of that capex, where ex post review forms part of the AER's incentive approach). The NSP would begin to earn a return on, and depreciation of, the additional expenditure from that time.

Again, the recent changes to the NER introduce the possibility of the AER being able to review the prudency of capex prior to rolling it into the RAB, where total capex

98 That is, the WACC * capex component associated with the additional expenditure, which is not reflected in the capital expenditure allowance for the regulatory control period.

99 Where the NSP's RAB is rolled forward on the basis of the amount of depreciation recalculated on the basis of actual (higher) expenditure, rather than the amount of depreciation allowed in the regulatory determination. The NSP therefore loses the depreciation associated with expenditure above the total capital expenditure allowance.

exceeds the capex allowance in the earlier regulatory determination. However, where the NSP overspends its overall allowance due to actual peak demand being higher than forecast, it would be expected that the AER would conclude that such additional expenditure was efficient (although the actual quantum of expenditure would be subject to review, including whether demand management would have represented a more efficient option).

Under the current NER the NSP therefore faces the risk during the regulatory control period that demand forecasts increase, requiring additional expenditure. However following the end of the regulatory control period, the cost of additional expenditure is passed through to consumers, and reflected in higher prices.[100]

B.1.3 Interaction with the demand forecasts adopted at the time of the determination

As noted above, the capex objectives in the NER require that the level of expenditure should be sufficient to meet expected demand for prescribed services over the regulatory control period, and further that the AER is to accept the expenditure where it reasonably reflects (amongst other things) a realistic expectation of demand forecasts.

Forecasts of the future level of peak demand will typically be developed across a number of different scenarios, which reflect different assumptions in relation to the key variables which are expected to drive future demand. There will be a range of different forecasts of future demand, and different people may reasonably hold different views in relation to whether a particular assumption is more or less likely.[101] As a consequence, there can be a range of 'realistic expectations' of future peak demand.

As discussed above, under the current NER customers bear the risk that if forecast demand falls below the level at the time of the determination, they are required to pay an amount relating to investment which is not then undertaken. In contrast, NSPs bear the risk associated with increases in peak demand above forecast levels requiring additional expenditure to that expected at the time of the determination.

The extent of these risks will depend on the strength of the specific incentive regime for capex applied. However, for any given incentive regime, the extent of the risk faced by customers and NSPs will also depend on the approach taken to setting the peak demand forecast at the time of the regulatory determination, and in particular how much weight is given to central, high and low variations of the forecast.

Where NSPs face the risk of having to undertake additional capex as a result of increases in forecast peak demand above the level assumed at the time of the regulatory determination, then they are likely to have a greater incentive to argue for the adoption of higher peak demand forecasts at the time of the determination, in order to minimise this risk. This would in turn result in higher capex forecasts, as additional projects relating to the higher forecast peak demand would be reflected in the forecast.

100 Again, the speed with which the cost would be passed through to customers will depend on the details of the capital expenditure sharing scheme adopted by the AER (if any).

101 See for example: AER, *Powerlink 2012-2017 Final Decision*, April 2012, p. 111. The AER disagreed with Powerlink over the inclusion and weightings of low, medium and high demand scenarios in the forecast model.

The AEMC has previously noted in its Chapter 6A decision a concern that if NSPs bear the risk of uncertain events that may cause them to:

> "Argue for the inclusion of the costs of uncertain projects in the revenue cap, which may cause customers to pay for costs that are never incurred or for projects that are not efficient. Subsequently this may result in a more intrusive form of regulation once the cost of this behaviour becomes evident." [102]

This point is equally valid in the case of NSP's bearing the uncertainty in relation to peak demand forecasts. Where the regulator accepts a peak demand forecast which gives considerable weight to 'high demand' scenarios, customers are automatically paying for a total capex allowance which is higher than may ultimately be required, if actual peak demand turns out to be below this level.

NSPs are likely to be more indifferent to using a forecast of peak demand prepared by an external party, or accepting a lower peak demand forecast, where there is a clear means of addressing any substantive downside risk that they face as a result. This in turn would result in customers bearing less of the risk associated with paying for expected investments which are not ultimately needed. The following section discussed the uncertainty mechanisms that are available under the current NER, and their applicability to managing the uncertainty relating to peak demand.

B.1.4 Managing demand uncertainty outside of forecasts

There are several mechanisms included in the NER to address uncertainty – namely contingent projects, capex re-openers and cost pass throughs. The AEMC has previously referred to these mechanisms as constituting the 'uncertainty regime.'

These mechanisms are potentially applicable to managing the uncertainty associated with changes in forecast peak demand during the regulatory control period, although may be better or worse suited for this task. These three mechanisms are discussed below.

Contingent project provisions

The NER provisions in relation to contingent projects are set out in clauses 6A.8 and 6.6A.[103] A contingent project mechanism has been available to TNSPs since 2006, but has only recently been applied to DNSPs as a consequence of the November 2012 changes to the NER. Previously contingent projects were not incorporated in the regulatory arrangements for DNSPs, due to concerns that the nature and profile of distribution capex was not well suited to a contingent projects mechanism and that uncertainty around distribution capex projects could be adequately dealt with via pass through provisions.[104] However the AEMC recently decided to incorporate contingent

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102 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18*, November 2006, p. 54.

103 The contingent project provisions in Chapter 6 applying to DNSPs were introduced as part of the AEMC's recent Rule Change process in relation to the Economic Regulation of Network Service Providers.

104 AEMC, *Rule Determination – National Electricity Amendment Rule 2012*, 29 November 2012, p. 183.

project arrangements in the NER for DNSPs, as on balance it considered that there were benefits in harmonizing the regime between transmission and distribution.

The NER allow an NSP to propose that a particular project should be treated as a 'contingent project' as part of a revenue determination, and for the AER to determine whether that project should be treated as a contingent project. In proposing that a particular project should be treated as a contingent project, the NSP needs to propose the total capex that will be required for the contingent project and the 'trigger event(s)' that would result in that project being required.

A project can only be accepted by the AER as a contingent project where the proposed total capex associated with the project exceeds the following thresholds:

- for transmission: either $30m or 5 per cent of the value of the maximum allowed revenue (MAR) for the relevant TNSP, whichever is the larger amount;[105] and
- for distribution: either $30m or 5 per cent of the value of the annual revenue requirement for the relevant DNSP, whichever is the larger amount;[106]

In addition, the proposed trigger events must be 'appropriate'.[107] In determining whether the proposed trigger events are appropriate, the AER must have regard to the need for the trigger event to meet a number of considerations (set out in clauses 6A.8.1(c) and 6.6A.1(c)), including whether occurrence of the event is 'probable' during the regulatory control period.

Where the AER determines that a specific project should be treated as a contingent project, the capex and operating expenditure associated with that project are not included in the total forecast capex and operating expenditure for the regulatory control period, and the resulting revenue requirement. Instead, the determination lists the contingent project, the indicative costs and the associated trigger events.

During the regulatory control period, if the trigger event(s) associated with the contingent project does not occur, then no further action is taken and there is no impact on the regulatory determination. That is, there is no impact on allowed revenue or prices from having included the contingent project in the determination, compared to a situation in which the contingent project had not been identified in the determination.

However if the trigger event(s) associated with the contingent project does occur during the regulatory control period, the NSP can apply to the AER to have the revenue determination amended, to reflect the contingent project.[108] In making this application, the NSP needs to provide a forecast[109] of the total capex for the contingent project as well as an estimate of the incremental revenue which the NSP considers is likely to be required for each remaining year of the regulatory control period.

105 NER clause 6A.8.1(b)(2)(iii).

106 NER clause 6.6A.1(b)(2)(iii).

107 NER clauses 6A.8.1(b)(4) and 6.6A.1(b)(4).

108 NER clauses 6A.8.2(a) and 6A.8.2(a).

109 This expenditure forecast does not need to match the expenditure forecast provided at the time of the earlier determination, but must be above the relevant threshold (ie, $30m or 5% of MAR or the annual revenue requirement) in order for the AER to accept the application.

If the AER is satisfied that the trigger event has occurred, and that the forecast capex exceeds the required threshold, it must then make a determination within 40[110] business days on:

- the amount of capital and incremental operating expenditure for each of the remaining years of the regulatory control period which the AER considers is reasonably required for the purposes of undertaking the contingent project;
- the corresponding incremental revenue which is likely to be required by the NSP; and
- the total capex which the AER considers is reasonably required for the contingent project.

In making this determination the AER is required to adopt essentially the same approach in assessing the proposed expenditure as applied to the expenditure forecasts at the time of the determination. That is, the AER is required to accept the NSP's proposed expenditure, if the AER is satisfied that the capex and incremental operating expenditure amounts reasonably reflect the capital expenditure criteria and the operating expenditure criteria,[111] taking into account the capex factors and the operating expenditure factors.[112]

The outcome of the AER's determination is an adjustment to the NSP's existing revenue determination to reflect the additional capital and operating expenditure required as a result of the contingent project. The AER's determination in relation to the total expenditure required for the contingent project (ie, expenditure in both the current regulatory control period and the next) is taken into account in determining the expenditure forecasts for the next regulatory control period, in order to preserve the incentives for the NSP to under-spend in relation to the contingent project cost estimate.[113] Utilisation of the contingent project mechanism represents a significant administrative process for both the AER and the relevant NSP.

However, the AEMC also notes that by treating uncertain, demand-related projects as contingent projects and excluding them from the main expenditure forecast, this preserves the incentives on NSPs to seek to defer or reduce spending in relation to the projects on which the expenditure forecast is based. As such, the use of the contingent project mechanism may actually enhance the incentive properties of the current regime, rather than undermine them. In addition, as noted earlier, the NER incorporates incentive arrangements in relation to expenditure on the contingent

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110 NER clauses 6A.8.2(d) and 6.6A.2(d).

111 As defined in NER clauses 6A.6.7(c), 6A.6.6(c), 6.5.7(c) and 6.5.6(c).

112 As defined in NER clauses 6A.6.7(e), 6A.6.6(e), 6.5.7(c) and 6.5.6(c).

113 The details of the treatment of the total contingent project cost in determining the expenditure allowance for the next regulatory control period are set out in NER clauses 6A.6.7(g)-(k) and 6.5.7(f)-(j). The NER ensure that the TNSP retains any benefit for under spending capex in relation to the project estimate (or bears the penalty for any overspend compared to the estimate) until the end of the next regulatory control period. As a consequence, where a project is treated as a contingent project, the NSP continues to have incentives for efficient expenditure in relation to that project (and face penalties for over-spending), just as if it had been included in the regulatory determination.

project itself, where the expenditure extends from the current regulatory control period into the next period.[114]

Application to uncertainty in relation to peak demand forecasts

Changes in peak demand forecasts are driven by external factors, and so uncertainty in relation to future peak demand can potentially be addressed via the contingent project frameworks. There are some examples of the contingent project mechanism having been adopted in order to address the uncertainty associated with future peak demand projections. Several of the contingent projects approved by the AER to date relate to specific but uncertain spot load developments.[115] However there are also examples where contingent projects have been identified which would be triggered by increases in peak demand forecasts in a particular location. For example, the AER approved three 500 kV network development projects as contingent projects in its final determination for Powerlink for its 2012-13 to2016-17 regulatory control period. These projects were initially included within Powerlink's forecast expenditure requirements. However the AER determined that they would be more appropriately treated as contingent projects. The AER noted that while the projects were needed to address network limitations, the timing was uncertain because projected demand over the regulatory control period was insufficient to require the project.[116]

In its recent draft decision for ElectraNet, the AER rejected a number of ElectraNet's proposed contingent projects on the basis that it considered that they sat in a band between ElectraNet's medium and high demand scenarios and that ElectraNet's forecast capex would be sufficient to meet these contingent projects.[117] However the AER went on to suggest that ElectraNet may want to propose some additional contingent projects, in the light of the AER's adoption of a revised (lower) demand forecast:

> "In light of the AER's revised demand forecast, the AER considers that some of these contingent projects might now be relevant if a lower demand forecast is applied in the final decision. It might therefore be necessary for ElectraNet to propose some additional contingent projects in its revised revenue proposal."

The AEMC notes that the contingent project mechanism is asymmetric in that it allows the NSP's revenue requirement to be adjusted upwards where changes in peak demand forecasts require additional capital investment, but does not result in a corresponding reduction in the NSP's revenue requirement where changes in forecasts mean that investment is no longer needed.

However, the extent to which such asymmetry is a concern needs to be considered in the context of the basis on which the peak demand forecast used in the determination has been developed, and in particular the extent to which 'high' scenarios of peak demand have been reflected in the forecast.

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114 These arrangements are set out in NER clauses 6A.6.7(g)-(k) and 6.5.7(f)-(j).

115 These include large mining spot loads or other major industrial loads.

116 AER, *Final Decision Powerlink 2012-17*, April 2012, pp. 114-119.

117 AER, *Draft Decision, ElectraNet Transmission Determination 2013-2018*, November 2012, p. 44.

Where there is considered to be an equal likelihood of the peak demand forecast being exceeded or for peak demand to fall short of the forecast, then allowing for adjustments to the revenue requirement in one case or not the other would result in an upward bias in the likely revenue requirement received by the NSP. However where the peak demand forecast adopted is one which is more conservative, with less weight given to potential 'upside' factors which could increase demand, the chance of there being an upward revision in forecasts is likely to be greater than there being a downward revision. The asymmetric impact of the contingent project mechanism is not a concern in this context, as the capex allowance included in the determination would have been stripped of those projects that were considered to be 'uncertain', based on a conservative (low) peak demand forecast. [118]

In addition, one of the capex factors which the AER is required to have regard to[119] is whether the total capex proposed by the NSP includes amounts relating to a project that should more appropriately be included as a contingent project. A similar factor applies to the AER's consideration of the NSP's proposed opex.[120] As a consequence, the AER has the ability to exclude from the expenditure allowances, expenditure associated with projects where it considers that it is not sufficiently certain that the event or condition will occur during the regulatory control period. This could potentially include capital investment which would only be required under high peak demand forecasts, and may make it more likely for the expenditure forecasts reflect more conservative demand estimates.

The AEMC also notes that use of the contingent project mechanism to address uncertainty in relation to peak demand forecasts may increase the administrative burden on the AER and NSPs, and represent a move away from the current arrangements under which NSPs and customers bear demand risk. The extent to which this is the case will depend on how frequently the contingent project mechanism would be expected to be triggered (as opposed to the number of contingent projects incorporated in a regulatory determination). To date the number of contingent projects which have been triggered remains low, as set out in Table B.1.

118 The impact between the demand forecasts adopted at the time of the determination, and the consequent risks to both customers and NSPs was discussed earlier in section B.1.3.

119 NER clauses 6A.6.7(e)(10) and 6.5.7(e)(9a).

120 NER clauses 6A.6.6(e)(10) and 6.5.6(e)(8).

Table B.1 Number of Contingent Projects Allowed in Final Decisions vs. Number Triggered

Business	Regulatory control period	Number of contingent projects allowed in Final Decision	Number of contingent projects triggered*
Powerlink	2012/13 – 2016/17	12	0
TransGrid	2009/10 – 2013/14	15	0
Transend	2009/10 – 2013/14	9	0
ElectraNet	2008/09 – 2012/13	19	2
Powerlink	2007/08 – 2011/12	11	1

** As of 31 August 2012.*

Source: AER Final Determinations and Contingent Project Applications. Note that a contingent project was also triggered for EnergyAustralia's (now AusGrid) transmission business, in 2008.

Other uncertainty mechanisms

There are two other mechanisms under the NER that are also used to manage the cost impact from uncertain events, and apply to both TNSPs and DNSPs, namely:

- the capex reopener provisions in clause 6A.7.1; and 6.6.5; and
- the cost pass through provisions in clause 6A.7.3 and 6.6.1.

The extent to which these other NER mechanisms could be used to manage the risk associated with changes in peak demand forecasts over the regulatory control period appears more limited.

Capex re-opening provisions

The capex reopening provisions are set out in clauses 6A.7.1 and 6.5.5 of the NER. The provisions allow a NSP to apply to the AER to revoke and substitute a revenue determination, where an event that is beyond the reasonable control of the NSP has occurred during the regulatory control period and where the NSP proposes to undertake additional capex to rectify the adverse consequences of the event, which wasn't foreseen at the time of the determination.

The threshold for the use of the capex re-opening provisions is that the total value of the capex required during the remainder regulatory control period exceeds 5 per cent of the value of the NSP's RAB for the first year of the relevant regulatory control period.[121] This represents a substantial hurdle, ranging from around $50m to more than $220m on current RAB values for TNSPs and $30m to over $400m on current RAB values for DNSPs.

The threshold for the use of this provision is above that for the use of the contingent project mechanism or the cost pass-through mechanism. The AEMC has previously noted that the re-opening provisions are intended to be a 'last resort', only triggered by

121 NER clauses 6A.7.1(a)(4)(i) and 6.6.5(a)(4)(i).

'large, shipwreck-type events'.[122] Indeed, to date the capex reopening provisions have not applied in practice.

The NER explicitly notes that 'an event' may include 'a greater than anticipated increase in demand'.[123] However, from the level at which the threshold for activating the re-opening provisions has been set it is clear that the capex re-opening provisions are not intended to be the primary mechanism to address the cost impact on NSPs of demand forecast changes. However the reopener provisions would be able to be used where the change in demand forecast was not able to be identified at the time of the determination (and so could not have been addressed via the inclusion of a contingent projects), and was of a size that would warrant use of the 'ship-wreck' provision. An example referred to by the AEMC at the time of its Chapter 6A determination was the development of a desalination plant, which could emerge suddenly and lead to a substantial increase in demand, and, as a consequence, required network investment.[124]

The mechanism is one-way, and so could not be used to re-open the determination where there has been a substantial reduction in peak demand over the period.

Cost pass-through provisions

The NER allows cost pass through for NSPs for additional operating and capex costs for certain defined events which fall within the scope of a 'pass through event'.[125]

A number of pass through events are defined in the NER. However NSPs are also able to nominate additional cost pass through events in their proposals as part of the determination process.[126]

In principle, NSPs could nominate a 'demand forecasting event', in order to be able to use the cost pass through mechanism as a means to manage their demand forecasting risk. However any such proposal would need to be approved by the AER, following an assessment against the nominated cost pass through considerations set out in the NER. These considerations are:

- whether the nature or type of event can be clearly identified at the time the determination is made;
- whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;
- whether the relevant service provider could insure against the event;
- whether the event can be self-insured; and
- any other matter the AER considers relevant.

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122 AEMC, *Draft Rule Determination, National Electricity Amendment (cost pass through arrangements for network service providers) Rule 2012*, May 2012, p. 17.

123 NER clauses 6A.7.1(a) and 6.6.5(a).

124 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18*, p. 61.

125 NER clauses 6A.7.3 and 6.6.1.

126 NER clauses 6A.7.3(a1)(5) and 6.6.1(a1)(5).

We note that Ausgrid previously proposed a 'cost or demand variance event' to cover unexpected or unforeseeable changes in demand or cost movements that trigger new investments or materially alter the costs of current or planned investments.[127] The AER did not approve the inclusion of this event as a cost pass through event on the grounds that the event was not expected to occur and therefore did not satisfy the foreseeability requirement. The AER considered that Ausgrid would be better placed to manage the risk of a cost of demand variance event and that allowing it as a specified pass through would undermine regulatory incentives.

Even if the NSP were to propose a 'demand forecasting' event as a pass through event, and this was accepted by the AER, the evaluation frameworks under the cost pass through mechanism appears to make it less appropriate to apply to substantial changes in demand-driven investments.

An NSP is able to apply for cost pass through where the cost of the event is 'material', which is defined as exceeding 1 per cent of the MAR or annual revenue requirement for that regulatory year. Under the NER, a cost pass through application must be made by the NSP within 90 business days of the pass through event occurring,[128] and must be a single, forward-looking estimate of the costs the NSP considers that it is likely to face over the remainder of the regulatory control period as a consequence of the event occurring. In evaluating the NSP's cost pass through application, the AER is required to consider a number of factors set out in the NER.[129] These include the efficiency of the NSP's decisions and actions in relation to the risk of the event occurring, and whether the NSP could reasonably have taken any action which would reduce the amount of costs incurred.

It appears unlikely that the NSP would be in a position to estimate the cost of the change in network investment that would be required, 90 days following an increase or decrease in peak demand forecasts. This timeframe is also much shorter than required for the application of the regulatory investment tests, which is likely to be required for network investment related to meeting increased peak demand forecast.

The evaluation criteria for a cost pass through application also differ from the criteria applied to assessing capex at the time of a determination (as set out in clause 6A.6.6 and 6A.6.7 of the NER). In addition, under the cost pass through mechanism, there would be no explicit incentive mechanism applied to the expenditure

B.1.5 Regulatory investment tests: RIT-T and RIT-D

The current NER incorporates a requirement for NSPs to apply a regulatory investment test to the majority of network investments, including those driven by the need to meet reliability standards in the face of increasing peak demand. The application of the regulatory investment test is separate to the periodic regulatory determination process, and relates to individual network investments (or related series of investments). The NER set out separate investment tests for transmission (the Regulatory Investment Test for Transmission, or RIT-T) and distribution (the

127 AER, *Final Decision New South Wales distribution determination 2009–10 to 2013–14*, April 2009, p. 291.

128 NER clauses 6A.7.3(c) and 6.6.1(c).

129 NER clauses 6A.7.3(j) and 6.6.1(j).

Regulatory Investment Test for Distribution, or RIT-D). The RIT-T and RIT-D are required to be applied to all network investment, with a number of limited exceptions set out in the NER.[130]

The NER required that the regulatory investment tests are required to be based on a cost-benefit analysis that must include an assessment of reasonable scenarios of future supply and demand.[131] The RIT-T itself further notes that the reasonable scenarios may include 'a reasonable forecast of electricity demand reflecting assumptions regarding economic growth and climatic patterns.'[132]

The NER require the NSP to set out the identified need for an investment, and the assumptions used in identifying the identified need, as part the first stage of the regulatory investment test process (ie, the Project Specification Consultation Report in the case of TNSPs, and the Non-network Options Report in the case of DNSPs).[133] In practice, increases in peak demand forecasts, including the development of additional spot load developments, are a key component of the 'identified need' for an investment (defined under the NER as the objective an NSP seeks to achieve by investing in the network). This is particularly the case where the investment is being driven by the need to meet reliability requirements. As part of the regulatory investment test process, the NSP therefore typically sets out the forecasts of peak demand which underpin its assessment of the need to undertake the investment.[134] These demand forecasts reflect the most recent demand forecasts available at the time at which the PSCR or Non-network report is being published, rather than being tied to the peak demand forecasts used in a previous regulatory determination. In addition, where peak demand forecasts change between the initial PSCR/non-network stage and the later Project Assessment Draft Report (PADR), which would lead to the investment timing and possibly the investment options themselves being revised at the time at which the PADR was issued.[135]

The requirement to apply a regulatory investment test to network investment therefore acts as a further point at which the need for the investment is assessed, and subject to public consultation. In most cases this will include an assessment against the most recent peak demand forecasts. Where an investment has been included as part of the capex allowance in a regulatory determination, and peak demand forecasts subsequently fall, then the later application of the regulatory investment test would use these lower peak demand forecasts, and may show that the investment can be deferred (including by using demand management), or that a smaller augmentation is now required. This application of the regulatory investment test, by providing a transparent assessment of the need for the investment, and potential alternative options (including demand management) therefore serves to further support the

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130 NER clauses 5.17.3(a) and 5.16.3.

131 NER clauses 5.17.1(c)(2) and 5.16.1(c)(1).

132 AER, *Regulatory Investment Test for Transmission*, paragraph (15)(a). The AER is currently consulting in relation to developing the RIT-D, in compliance with NER clause 5.17.1.

133 NER clauses 5.17.2(e)(1)-(2) and 5.16.4(b)(1)-(2).

134 See for example, Transend, *Kingston Area Augmentation, Project Specification Consultation Report*, Sept 2011, Section 2.

135 See for example ElectraNet, *Lower Eyre Peninsula Reinforcement, PADR*, January 2013, section 2.

incentives under the NER for NSPs to defer or scale-back investment, where forecast peak demand falls.

The regulatory investment test process typically takes 15 to 18 months. The regulatory test process may occur following a regulatory determination, in which case it represents a further evaluation of the need for the investment compared to the forecasts at the time of the determination. In this circumstance, the regulatory investment test may form part of a trigger for the investment to be treated as a contingent project (and as a consequence, the expenditure associated with the investment would not have been included in the earlier regulatory determination).

The regulatory investment test may also be applied prior to a regulatory determination, where the need for the investment was identified later in the preceding period. The resulting project would then form part of the capex forecast for the following period. In this circumstance there would be no further formal regulatory requirement to assess the need for the project following the regulatory determination. However it is also more likely under this scenario that the investment would proceed earlier in the regulatory control period rather than later (otherwise the application of the regulatory investment test would have itself been delayed), with potentially less likelihood for peak demand forecasts to have changed in the intervening period.

The recent rule changes which introduce the RIT-D further provide that if there is a material change in circumstances which, in the reasonable opinion of the RIT-D proponent means that the preferred option identified in the final project assessment report is no longer the preferred option, then the RIT-D proponent must reapply the RIT-D, unless otherwise determined by the AER.[136] A material change in circumstances may include (but is not limited to) a change in the key assumptions used in identifying the identified need. Changes in peak demand forecasts therefore fall under the scope of a change in circumstance.

The AER has earlier noted that it considers it is best practice for DNSPs to reply the RIT-D where there is a material change in circumstance. However the AER also raised concerns that these NER provisions do not deal well with situations in which the material change is a change in demand forecast which delays the time at which the investment is required.[137] The AER suggested that in these circumstances the RIT-D not be reapplied immediately, but instead be delayed until the identified need is projected to arise again.

There is currently no formal equivalent requirement under the NER in relation to the reapplication of the RIT-T. The AER has previously commented that it considers that a similar reapplication provision should be introduced for the RIT-T.[138]

We note that there is an explicit requirement under both the RIT-T and the RIT-D for the NSP to consider and consult on non-network options, including demand management options. In some circumstances, demand management may be able to be used to efficiently defer the time at which a network augmentation is needed, resulting

136 NER clause 5.17.3(t).

137 AER submission to the AEMC distribution network planning and expansion draft rule determination and draft rule, 9 August 2012, p. 5.

138 Ibid.

in a lower cost option overall. Where there is substantial uncertainty in relation to future demand levels, an option which incorporates demand management in order to defer the time at which the network augmentation is undertaken may also have 'option value'. Where the deferral of network investment is expected to result in future peak demand forecasts being more certain at the time of the augmentation, and for the augmentation to then be better specified as a result, this would represent an additional category of market benefit associated with the deferral option. The current NER allows for the incorporation of option value into the regulatory investment test assessments, where it is material.[139]

In addition to the regulatory investment test process, the we also note that network investments to meet increasing peak demand forecasts typically have a long lead time, and encompass several distinct phases. As such, where peak demand forecasts fall, it may not be prudent and efficient for NSPs to defer or cease investments which have already completed major pre-investment phases. In particular, once the procurement process has started for a particular investment, deferral of that process may be costly. In addition, where there is uncertainty as to whether the reduction in demand is expected to be prolonged, and where there is also the potential for a later 'bounce-back' to higher levels, it may still be prudent for an NSP to continue with its planned investment.

Notwithstanding this point, there are several potential pre-investment phases which could potentially be put 'on hold' when demand forecasts fall. NSPs would have incentives to defer investments in relation to reductions in peak demand forecasts as a result of the incentive provisions in the NER (discussed earlier). Box B.1 provides further discussion of the lead times associated with network investment.

139 NER clauses 5.16.1(c)(4)(ix) and 5.17.1(c)(4)(vi).

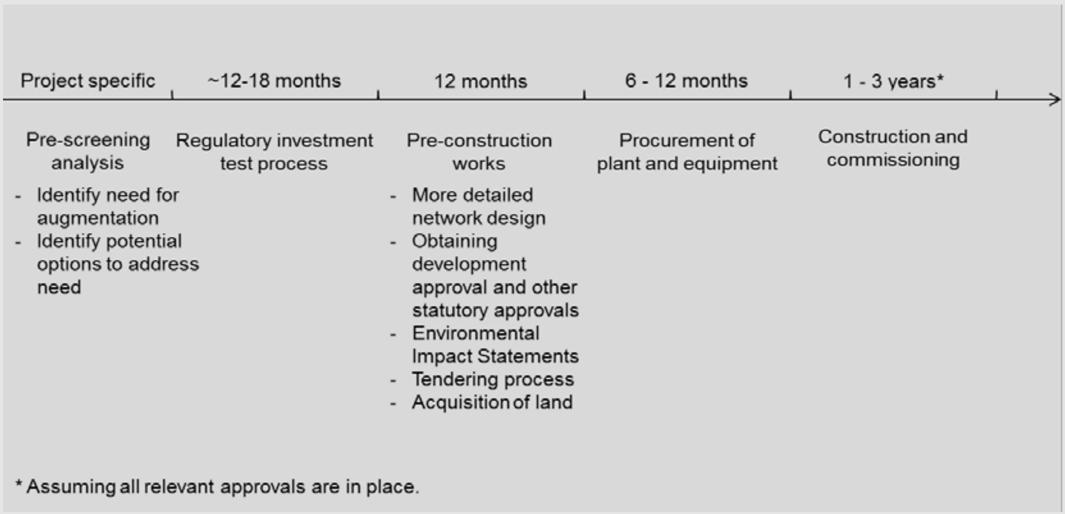
Box B.1: Nominal timeline for a network augmentation

There are a number of distinct stages that must be undertaken before a network augmentation becomes operational. NSPs must begin committing to a network augmentation far in advance of the actual date at which the augmentation is required.

The length of time required for each stage depends on the specific option(s) being contemplated and can vary greatly. For example:

- Powerlink released the first report under the RIT-T process for the Bowen Basin coal mining area approximately 19 months before the supply augmentation was expected to be required to be installed and operational;[140] and
- CitiPower first undertook a regulatory test for the proposed augmentation for Melbourne inner suburbs and CBD supply in 2008, 6 years before an augmentation was expected to be required.[141]

Each of the stages, along with the nominal time required for each are set out in the timeline below.[142]



In addition, there are certain state-specific requirements relating to certain stages of this process. For example, the Electricity Transmission Code in South Australia suggests all land easements and necessary approvals should be acquired three years in advance of the anticipated date of the breach of the relevant reliability standard.

140 See Powerlink, (2012), *Summary of Project Specification Consultation Report - Maintaining a Reliable Electricity Supply to the Bowen Basin Coal Mining Area*, 27 April 2012.

141 CitiPower, (2011), *Brunswick Terminal Station News Release*, 12 February 2011.

142 We note that the timeline is only intended to be indicative and there is likely to be overlap between the various tasks. For example, a NSP may strategically acquire land before the regulatory investment test process is complete.

B.1.6 Optimisation of the RAB

SCER's Request for Advice requested the AEMC to provide advice on the merits of the AER considering the difference between actual and forecast demand in the prior determination period when undertaking the current determination. The AEMC has also been asked to determine whether amendments to the NER are needed to ensure that consumers receive the benefits of sustained reductions in demand, including but not limited to improvements to the AER's ability to consider utilisation of previously approved capex. SCER also required that in proposing any amendments, the AEMC should have regard to the need to maintain stability and predictability in the regulatory regime, including ensuring sufficient capital investment certainty for infrastructure provision and the ability to obtain capital at reasonable rates to facilitate this.

There are currently no general provisions in the NER for adjustment of the RAB at the time of a regulatory determination to account for the degree of utilisation of previously approved capex. The one exception is for TNSPs, where assets which are dedicated to one transmission network user (not being a DNSP) or a small group of transmission network users, and where the value of the asset (or group of assets) at the start of the regulatory control period is greater than the indexed amount of $10m can be removed from the RAB, provided that:[143]

- the AER determines that the assets are no longer contributing to the provision of prescribed services; and
- the AER determines that the relevant TNSP has not adequately sought to manage the risk of such asset no longer contributing to the provision of prescribed transmission services.

In addition, the AER may determine a separate amount which is to be included in the building block revenue requirement to compensate the TNSP for the risk of the value of assets being removed from the RAB.

To date, this mechanism has not been applied.

In contrast, the National Gas Rules do include provisions for 'redundant' investment to be excluded from the RAB (where they no longer contributes to the delivery of pipeline services.[144] Where those assets subsequently contribute to the delivery of pipeline services, they can be later added back into the RAB.

We note that in November 2011 the MEU submitted a rule change request to the AEMC for the inclusion of optimisation of the asset base in the NER. The MEU's proposed rule would have required the AER to periodically review the existing asset base and exclude assets that are unutilised or underutilised from the RAB.[145] The MEU argued that asset base optimisation would prevent consumers from paying a rate of return to service providers for assets which are not utilised or are underutilised.

143 NER clauses S6A.2.3 and 6A.5.4(b)(7).

144 National Gas Rules, Part 9, Division 3, Clause 85 and 85.

145 AEMC, *National Electricity Amendment Rule 2012 – Rule Determination*, 13 September 2012, p. 1. The proposed rule also covered the replacement of fully depreciated assets which can be still be used.

In its review of the MEU's proposed rule change, the AEMC determined not to make a change in the NER to permit optimisation of the RAB, on the basis that such optimisation:[146]

- could increase the risk to service providers and therefore provide disincentives for future investment;
- could increase the complexity, costs and resourcing of the regulatory process; and
- would require the regulator to perform too detailed a role in approving a service provider's projects and plans.

The AEMC noted as part of its determination that, unlike a competitive business, a regulated service provider has an obligation to invest to meet expected demand growth regard regardless of the likely risk, including the risk that expected demand does not eventuate.[147] Service providers are not compensated for additional risk with a higher rate of return. The AEMC had regard to the limitations and obligations placed on service providers in its decision not to adopt asset base optimisation.

B.1.7 Incentives for demand management

In 2011 the NER were amended to require the AER to develop a demand management and embedded generation connection incentive scheme (DMEGCIS).[148] The DMEGCIS is a revision of the previous demand management incentive scheme (DMIS), which was been extended to include embedded generation research.

Clause 6.6.3(a) sets out that the objective of DMEGCIS as "to provide incentives for DNSPs to implement efficient non-network alternatives, or to manage the expected demand for standard control services in some other way, or to efficiently connect embedded generators".[149] In developing and implementing DMEGCIS, the AER must have regard to a number of factors set out in the NER, including:

- the effect of a particular control mechanism (i.e. price - as distinct from revenue - regulation) on a DNSP's incentives to adopt or implement efficient non-network alternatives; and
- the extent that the DNSP is able to offer efficient pricing structures.

The AER released its proposed approach to DMEGCIS to apply in the 2014-2019 Ausgrid determination in May 2012.[150] DMEGCIS is comprised of two parts:

- Part A is called the Demand Management Innovation Allowance, provides DNSPs with a fixed amount of additional revenue at the start of each year to conduct research and innovation on demand management techniques; and

146 AEMC, *National Electricity Amendment Rule 2012 – Rule Determination*, 13 September 2012, p. ii.

147 Id., p. 6.

148 NER clause 6.6.3.

149 NER clause 6.6.3(a).

150 The determination period for Ausgrid has since been amended, as part of the transitional provisions associated with the Economic Regulation of Network Service Providers Rule change.

- Part B allows DNSPs to recover foregone revenue from the previous year that resulted from a reduction in the quantity of energy sold directly attributable to demand management project undertaken under Part A of DMEGCIS.[151] Part B only applies to DNSPs which are subject to a control mechanism in which the recovery of the annual revenue requirement is dependent on energy sold.[152]

Under the AER's proposed DMEGCIS, foregone revenue under part B is to be calculated:

- with reference to approved forecasts in the DNSP's relevant distribution determination;
- in a manner consistent with the control mechanism that applies to the DNSP's standard control services; and
- including only foregone revenue which results from non-tariff demand management initiatives.[153]

The AER subsequently decided to delay its final decision until the finalisation of the AEMC's *Power of Choice* review.[154]

As part of its *Power of Choice* review, the AEMC considered the incentives under the NER in relation to demand management in depth, and recommended that the NER be amended to reform the application of DMEGCIS so that it:

- provides an appropriate return for demand side participation (DSP) projects that deliver a net cost saving to consumers; and
- better aligns network incentives with the objective of achieving efficient demand management.[155]

The AEMC's recommended changes to DMEGCIS are intended to address concerns that the existing scheme does not adequately provide an incentive for distributors to explore and develop DSP options instead of capital investment. The overall objective of the reform is to help level the playing field between capital investment and DSP projects. The details of the proposed changes have not yet been developed by the AER, and so it is unclear whether the reformed DMEGCIS will effectively encourage demand management as an alternative to network augmentation.

In its recommendation, the AEMC gives the AER discretion in determining the design and application of the DMEGCIS. However, the AEMC has proposed a number of features which the AER should to include in the revised DMEGCIS. The revised DMEGCIS must:

- complement the normal expenditure determination process and planning arrangements;

151 AER, *Proposed demand management and embedded generation connection incentive scheme*, May 2012, p. 15.

152 Id., p. 11.

153 Id., p. 18.

154 See http://www.aer.gov.au/node/15100.

155 AEMC, *Final Report, Power of Choice Review*, 30 November 2012, p. 205.

- not reward a network business for doing DSP activities which do not deliver a corresponding net benefit across the supply chain to consumers. Therefore DSP projects assessed as being efficient quantify for the potential incentive payment offered under this scheme;
- cover all forms of demand side participation, including distributed generation;
- pay rewards which reflect the timing of benefits, in order to smooth the bill impact on consumers;
- include a maximum percentage of non-network expenditure related market benefits (i.e., generation cost savings) which can be retained by network businesses (the actual percentage may vary by business and by time);
- provide that projects approved under this scheme must undergo the same cost approval process as all capital or operating expenditure;
- ensure that DSP projects address an underlying network issue in order to qualify for inclusion in the incentive scheme;
- recognise the need to incentivise networks over the long term and not just the forthcoming regulatory control period;
- include methodologies to measure the extent of the consumer demand response should be consistent with the baseline consumption methodologies approved for the demand response mechanism proposed for the wholesale market;
- include an allowance for profit foregone due to the decrease in throughput volumes due to DSP projects approved under the DMEGCIS or as part of the distribution determination process; and
- give the AER the ability to impose penalties for non-compliance with performance standards.[156]

156 Id., pp. 207-208.

B.2 Impact of differences between forecast and actual demand on revenue recovery

Summary

The form of control mechanism adopted for price changes during a regulatory control period affects the volume risk and subsequent profitability risk faced by NSPs and customers, where actual demand outcomes during the period differ from forecast demand.

The NER requires TNSPs to be subject to a revenue cap form of control mechanism. The AER determines the form of control mechanism to be applied to DNSPs (which may be a revenue cap, a WAPC or some other alternative), having regard to criteria set out in the NER. The AER has considered the implied volume risk, as well as the incentives for demand management, in making its decision on the appropriate form of control mechanism.

Under a revenue cap, the NSP will earn the same amount of revenue regardless of whether demand is higher or lower than that forecast at the time of the regulatory determination. Volume risk is therefore borne by customers rather than the NSP. A revenue cap does not undermine an NSP's incentives to undertake demand management.

However a revenue cap does not provide an NSP with incentives to adopt efficient tariff structures, since the revenue they earn is independent of their tariffs. A revenue cap may provide incentives to adopt inefficient tariff structures, as by increasing prices more on price-sensitive services, an NSP may be able to reduce demand for those services and therefore their costs.

A WAPC exposes NSPs to a greater degree of volume and profitability risk where demand differs from forecast. NSPs have an incentive to propose conservative (low) demand volumes at the time of the determination. The lower the assumed volumes, the higher are the tariffs required in order to result in the same expected tariff revenue, and therefore the lower the calculated X factors.

During a regulatory control period, NSPs are able to rebalance their tariffs. A WAPC in theory provides incentives for NSPs to adopt more efficient pricing structures, as a means of addressing the profitability risk they face. However they also face incentives to increase tariffs the most on the fastest growing tariff components, due to the use of lagged actual quantities (ie, q_{t-2}) in the WAPC price control formula.

Incentives for NSPs to undertake demand management are adversely affected by a WAPC form of control. However the DMEGCIS is intended to counteract this incentive, by allowing prices to be adjusted to reflect foregone revenue. The changes to the DMEGCIS proposed by the AEMC in its Power of Choice review would further address this issue.

The AER's regulatory determination sets out allowed revenues for the regulatory control period (typically five years). As discussed in the previous section, demand forecasts (particularly forecasts of peak demand) are a key input in determining the expected efficient level of expenditure required over the regulatory control period, and therefore allowed revenues.

The translation of allowed revenues into prices also depends on forecast demand. Forecast tariff revenue depends on the tariffs proposed, and also the volumes expected to be sold in relation to each of the parameters of the proposed tariffs. Forecasts of customer numbers, volumes (kWh) and maximum demand (kW, where tariffs include a demand charge) all impact the expected level of revenue associated with proposed tariffs (together with any other parameters which are reflected in tariffs).

The regulatory determination sets out the basis on which the NSP's initial prices in the first year of the regulatory control period will be approved (ie on the basis of recovering the (smoothed)[157] revenue requirement in the initial year of the regulatory control period). It also determines the mechanism by which prices will be permitted to change over the remaining years of the regulatory control period. This mechanism is termed the 'control mechanism'.

The actual revenue earned by the NSP over the regulatory control period will depend on the form of control mechanism adopted. Under some forms of control mechanism (eg a WAPC or an average revenue cap), the amount of revenue earned by the NSP will differ from the allowed revenues forecast at the time of the regulatory determination, where actual outturn demand differs from forecast demand. Under a revenue cap form of control, the amount of revenue earned by the NSP over the regulatory control period is set equal to the allowed revenue at the time of the determination, with an 'unders-and-overs' mechanism applied in order to adjust annual revenues for any shortfall (over-recovery) against forecast revenues in the previous year, due to demand being lower (higher) than expected. The form of control mechanism therefore determines how the NSP's revenues vary (if at all) due to differences between forecast and actual demand over the regulatory control period, and therefore the profitability risk faced by the NSP, and the risk borne by customers.

The remainder of this section discusses:

- the NER provisions in relation to the form of control, which differ between Chapter 6 (DNSPs) and Chapter 6A (TNSPs);
- AER practice to date in determining the form of control to apply to DNSPs; and
- the linkages between the form of control, the actual revenue received by the NSP and the resulting profitability risk faced by the NSP and the volume risk borne by customers, in the context of differences between actual and forecast demand.

In the discussion of volume risk throughout this section we have focused on volumes sold (ie, kWh), as constituting the bulk of the 'demand risk'. However as noted above, volume risk potentially applies to all of the parameters included in NSPs' tariffs.

157 The revenue requirement identified as a result of the building block methodology is typically 'smoothed' so that the allowed revenue varies smoothly over the period, in order to minimise the associated price changes both between years during the regulatory control period, and also between regulatory control periods. The 'smoothed' revenue requirement is equal to the 'building block' revenue requirement in NPV terms.

B.2.1 Form of control for DNSPs

NER provisions

For DNSPs, the AER is required to determine in its Frameworks and Approach paper the form of control mechanism to be applied to a DNSP in the upcoming regulatory control period.[158]

Clause 6.2.5(b) of the NER sets out the control mechanisms that the AER may select from in making this determination. Acceptable forms of control mechanism include:

- a schedule of fixed prices;
- caps on the prices of individual services (price cap);
- caps on the revenue to be derived from a particular combination of service (revenue cap);
- tariff basket price control (WAPC);
- revenue yield control ('average revenue cap'); or
- a combination of any of the above.

The AER is able to exercise its discretion in selecting which of the above control mechanisms to apply. Clause 6.2.5(c) of the NER lists the factors that the AER must have regard to in deciding on a control mechanism. These factors include:

- the need for efficient tariff structures;
- the possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users;
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination;
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and
- any other relevant factor.

During the regulatory control period, DNSPs are required to submit an annual pricing proposal to the AER which sets out the proposed prices to apply during the upcoming year.[159] The AER assesses annual pricing proposals to ensure that they comply with the form of control mechanism applying to that DNSP. DNSPs are required to submit revised forecasts of demand in relation to each charging element in their tariffs, as part of this annual assessment, ie including changes in forecast kWh usage in the following year.[160] Section B.3 discusses in more detail the current NER provisions in relation to permitted changes to DNSP's tariffs as part of this annual price approval process.

158 NER clause 6.8.1(f).

159 NER clause 6.18.2.

160 See for example Energex, *Pricing Proposal for the period 1 July 2012 to 30 June 2013*, 22 May 2012, pp. 13-14.

AER approach

To date, the control mechanisms determined by the AER have continued to reflect the mechanisms applied by the previous jurisdictional regulators for each DNSP. The control mechanisms currently applied to DNSPs in each jurisdiction are set out in the table below.

Table B.2 Control mechanisms by jurisdiction

State	Control mechanism
ACT	Average Revenue Cap[161]
NSW	WAPC (current). Revenue Cap from start of the 2014 regulatory period
QLD	Revenue Cap
SA	WAPC
TAS	Revenue Cap
VIC	WAPC

However, in its preliminary Frameworks and Approach Paper for the ACT and NSW DNSPs 2014-2019 determinations, the AER reassessed the appropriateness of the existing control mechanisms and proposed a change to the control mechanism (to a revenue cap in both cases).[162] Subsequently the AER has released a discussion paper on the formulae for control mechanisms, in which it indicates that it intends to apply an average revenue cap to ActewAGL in the upcoming regulatory control period.[163] The AER is required to finalise its position on control mechanisms to be applied in NSW and ACT in Part 1 of its frameworks and approach paper for the 2014-2019 regulatory control period by 31 March 2013.

The AER's assessment was based on the criteria set out in Clause 6.2.5 of the NER, as well as three additional criteria, which it set out in a discussion paper prior to the release of the NSW and ACT Frameworks and Approach Paper.[164] These three additional criteria were the impact of alternative control mechanisms on:

- volume risk and revenue recovery;
- incentives for demand side management; and

161 In its preliminary framework and approach paper, the AER proposed transitioning ActewAGL from an average revenue cap to a total revenue cap. However, the AER's recent discussion paper on the formulae for control mechanisms indicates that an average revenue cap will continue to be applied to ActewAGL. See AER, *Framework and approach paper– ActewAGL*, June 2012, p. 36 and AER, *Formulae for control mechanisms – Revised*, February 2013, p. 10.

162 AER, *Framework and approach paper – Ausgrid, Endeavor Energy and Essential Energy*, June 2012, p. 46 and AER, *Framework and approach paper– ActewAGL*, June 2012, p. 36.

163 AER, *Formulae for control mechanisms – Revised*, February 2013, p. 10.

164 AER, *Framework and Approach Paper - ActewAGL*, June 2012, p. 36.

- price flexibility and stability.[165]

The AER proposed the inclusion of a volume risk and revenue recovery criterion in order to address concerns around divergences between demand forecasts and actual demand. Specifically, the AER was concerned that under certain control mechanisms DNSPs may recover revenue above efficient costs if actual demand exceeds forecast demand.[166] Therefore, the AER considered that an assessment of the interaction between the form of control mechanism and level of volume risk should be included in the selection criteria for the control mechanism.

In proposing the inclusion of an 'incentives for demand side management' criterion, the AER commented that one of the most significant drivers of network costs is the requirement to build sufficient capacity to meet peak demand. Major reductions in DNSP costs could therefore be achieved through demand side management. The AER considered that the form of control mechanism in place affects a DNSP's incentive to implement demand side management and proposed that this interaction also be considered in selecting the control mechanism.[167]

Finally, the AER proposed the inclusion of an 'incentives to set efficient prices' criterion because it considered that the form of control mechanism applied affects a DNSP's incentive to set prices that reflect the cost of providing the service.[168]

B.2.2 Form of control for TNSPs

The NER requires all TNSPs to be regulated on the basis of a revenue cap.[169]

A revenue cap limits the maximum allowable revenue that a TNSP can earn in each year to a fixed amount based on the allowed revenue in the regulatory determination. TNSPs are subject to an annual 'true-up', which resets a TNSP's maximum allowable revenue for the following year based on adjustments to reflect any under- or over-recovery of revenue in the current year compared to allowed revenue (the unders and overs account).

The AEMC decided to codify the application of a revenue cap form of control for all TNSPs in its 2006 review of the NER for the economic regulation of electricity transmission revenue and pricing.[170] Prior to the AEMC's decision, TNSPs had all been subject to revenue caps under the regulatory approach adopted by the ACCC (as the previous regulator of transmission businesses).

The AEMC provided the following reasons for its decision to reapply revenue caps, at the time of its Chapter 6A determination:

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165 AER, *Matters relevant to the framework and approach, ACT and NSW DNSPs 2014-2019 – discussion paper*, April 2012, p. 6.

166 Id., p. 7.

167 Id., p. 8.

168 Id., p. 6.

169 NER clause 6A.4.2(a)(1).

170 AER, *National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18 – rule determination*, 16 November 2006.

- there was no compelling reason to move away from a revenue cap. Maintaining the current arrangement would provide consistency and certainty for TNSPs and their customers;[171]
- a revenue cap approach allows for the recovery of efficient costs and provides incentives for future cost efficiency;[172] and
- revenue caps, unlike tariff baskets or price caps, minimise the 'largely unmanageable volume risk for the TNSPs'.[173] TNSPs costs are largely fixed, and so do not vary with changes in kWh sold.

An earlier report from the Expert Panel on Energy Access Pricing also cited the fact that the costs of lumpy transmission investment are not related to individual demands, as to why a revenue cap is preferred for transmission:

> "The principal reason for applying revenue caps in electricity transmission is the lumpy nature of the capital investment and the very weak relationship between annual changes in transmission cost and demand or output. Transmission service providers also have only limited ability to influence the demand for their services."[174]

B.2.3 Volume risk differs depending on the form of control mechanism

Differences between the forecast volumes at the time of the regulatory determination and actual outturn demand have the potential to affect both the revenues received by the NSP during the regulatory control period and its costs (and hence profits). However, the specific impacts, and whether the volume risk is borne by NSPs or customers, depend on the form of control mechanism that applies.

This section discusses the three main forms of control mechanism currently applied to NSPs in the NEM (revenue caps, WAPC and average revenue caps), and for each the implications of differences between forecast and actual demand, in terms of NSPs' revenues and profitability risk, and the corresponding risk borne by customers.

Revenue cap

Mechanics

A revenue cap form of control is where there is a direct limit on the maximum allowed revenue (MAR) that a regulated business can earn in any year. Revenue caps are coupled with a 'truing-up' mechanism that deals with any unforeseen variations in demand that lead to an over-/under-recovery of target maximum revenue in any year.

The MAR for each year of the regulatory control period is established at the start of the regulatory control period, as part of the regulatory determination. The MAR is normally established using a CPI-X revenue path, where the X-factor is set to achieve a

171 Id., p. 40.

172 Id., p. 40.

173 Id., pp. 40-41.

174 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p. 114.

smoothed path of revenue over the regulatory control period, which is equal in NPV terms to the present value of the building block revenue requirement.[175]

For each year within a regulatory control period, a NSP's proposed prices are approved if:

Forecast revenue from proposed tariffs (Forecast demand x proposed tariffs)	≤	***MAR for that year***

The MAR for a particular year is equal to the (smoothed) annual revenue requirement plus any unders/overs adjustment, ie, the difference between the MAR for the previous year and the actual revenue earned by the NSP for that year.

As part of the annual price setting process, an NSP proposes new tariffs for the forthcoming year on the basis of its latest demand forecasts. Therefore, under a situation where kWh demand is falling relative to the forecasts at the time of the regulatory determination, prices per kWh will increase (all else equal) in order to recover the MAR (which remains unchanged). Conversely, per kWh prices would decrease (all else equal), under a situation where kWh demand is rising relative to expectations at the time of the regulatory determination. An example of a decrease in demand relative to initial expectations is outlined in Box B.2.

Under a revenue cap, customers therefore bear the risk that a decrease in demand over the regulatory control period will increase the prices they face over the period, but will benefit if demand is greater than forecast, reducing prices (all else equal).

Impact on NSP revenues when demand changes

Under a revenue cap, changes in outturn demand relative to forecasts do not affect the net present value of the revenue received by the NSP over a regulatory control period.

If outturn electricity demand falls below that forecast for a particular year, the NSP will earn less than the MAR for that year. However, to make up for this, the 'true-up' mechanism allows the NSP to receive the shortfall revenue, subject to an adjustment to take into account the time value of money, as part of their MAR in the following year. This is illustrated for the case of demand falling relative to forecasts in Figure B.1 below. An example of a decrease in demand relative to initial expectations is also set out in Box B.2.

Conversely, if electricity demand is greater than forecast for a particular year, the additional revenue earned by the NSP is returned to consumers by being subtracted off the MAR for the following year, reducing prices in that year compared with what they would have otherwise been.

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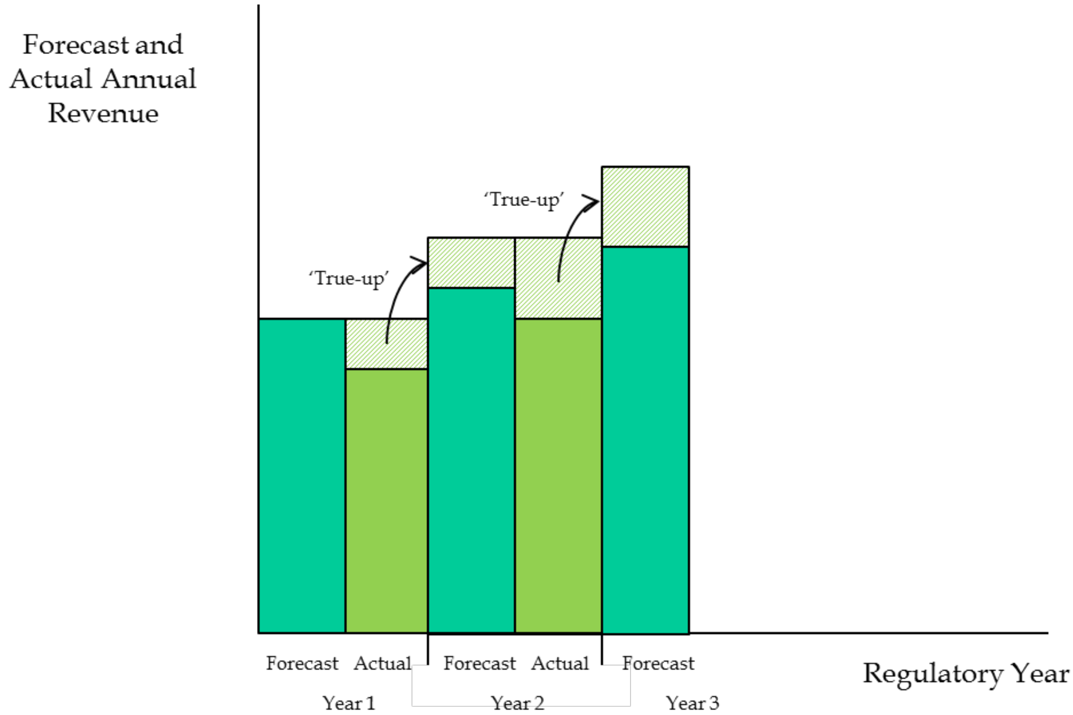
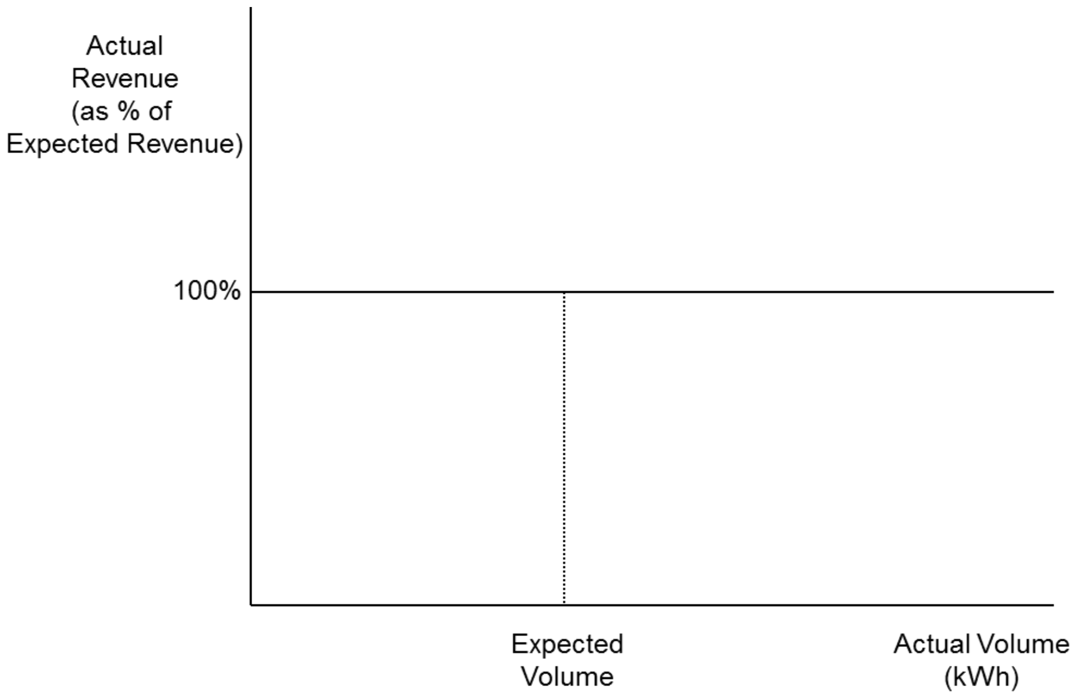
175 The current NER (clause 6A.6.8) states that for TNSPs, the X factor for each regulatory year must be such that: (1) the NPV of the expected MAR for each regulatory year (as calculated in accordance with the post-tax revenue model (PTRM)) is equal to the NPV of the annual building block revenue requirement for each regulatory year (as calculated in accordance with the PTRM); and (2) the expected MAR for the last regulatory year (as calculated in accordance with the PTRM) is as close as reasonably possible to the annual building block revenue requirement for that regulatory year (as calculated in accordance with the PTRM).

Figure B.1 The true-up mechanism under a revenue cap



Overall, a revenue cap provides the NSP with a guaranteed amount of revenue (in NPV terms) over the regulatory control period, independent of actual demand. Put another way, the actual revenue received by the NSP under a revenue cap is always exactly equal to the expected revenue at the time of the regulatory determination, regardless of whether actual volumes are above or below the forecast volumes at the time of the determination. Figure B.2 below illustrates this.

Figure B.2 Difference between actual and expected revenues where actual volumes differ from expected volumes



Impact on NSP profit from demand changes

As outlined above, under circumstances where demand falls relative to what was forecast for a particular year, the NSP will recover the same amount of revenue. However, the NSP's costs may also decrease with lower demand.

The extent to which NSPs' costs vary with volumes (and in particular kWh sold) is an empirical matter. As noted earlier, the majority of NSPs' costs are fixed, meaning that costs do not vary greatly with volumes, particular in the case of transmission businesses. However, some of the NSPs costs are variable and these costs would decrease with a fall in demand. In addition, as discussed in section B.1.2, the NSP may be able to defer or even avoid investment, where peak demand is lower.

Where the NSP's costs fall as a consequence of demand being lower than forecast, its profits would increase for that particular year (since revenues remain unchanged under a revenue cap). An example of the impact on NSP profits from a decrease in demand relative to initial expectations is provided in Box B.2.

Box B.2: Impact of falling demand under a revenue cap

Suppose an NSP has an annual fixed cost of $100/customer, a variable cost of $1/kWh and currently serves 1,000 customers. Suppose also that the NSP has a MAR for the upcoming year of $120,000 and it expects annual demand to be 20MWh.

If the NSP sets a fixed tariff of $70/customer and a variable tariff of $2.50/kWh the NSP would earn the following revenue and profit:

- Revenue: $120,000, ie, (1,000 customers x $70/customer) + (20,000kWh x $2.50/kWh); and
- Profit: $0, ie, $120,000 – [(1,000 customers x $100/customer) + (20,000kWh x $1.00/kWh)].

These tariffs would be approved, since the expected revenue is equal to the MAR.

If demand for the year turns out to be lower than the initial 20MWh expected, the NSP will collect less revenue in that particular year. For example, suppose that outturn demand is only 15MWh, the NSP would earn the following revenue and profit:

- Revenue: $107,500, ie, (1,000 customers x $70/customer) + (15,000kWh x $2.50/kWh); and
- Profit: -$7,500, ie, $107,500 – [(1,000 customers x $100/customer) + (15,000kWh x $1.00/kWh)].

However, under a revenue cap there would be a 'truing-up' of revenue in the subsequent period. Specifically, $12,500[176] (ie, $120,000 - $107,500) would be added to the following year's MAR, bringing it to $132,500 (for simplicity we have assumed the un-adjusted MAR for the subsequent year is again $120,000). The TNSP would benefit under this scenario, as the additional revenue added to the following year's MAR ($12,500) would more than offset the reduction in profit in the previous period (-$7,500).

As part of the annual price reset process, the NSP would again have an incentive to structure its tariffs so that it expects to earn its MAR for the year, ie, $132,500. In addition, the NSP would take account of the latest (lower) demand forecast when structuring tariffs for this subsequent period, ie, 15MWh.[177]

Assuming the NSP retains the level of its fixed tariff, it would then need to significantly increase its variable tariff in order to recover its second year MAR (inclusive of the 'true-up'). Specifically, the NSP would need to set a variable tariff of $4.17/kWh (an increase of 67%), ie, $132,500 – (1,000 customers x $70/customer)]/15,000kWh.

176 For simplicity, we have assumed dollars are in constant, real terms between periods and so a net present value calculation is not necessary.

177 For simplicity, we have assumed the reduction in demand is perceived by the NSP to be permanent in nature, rather than being perceived as being 'one-off'.

Conversely, under circumstances where demand increases relative to what was forecast for a particular year, the NSP will recover the same amount of revenue, even where its underlying costs increase. In this situation, the NSP's profits will fall for that particular year.

As discussed earlier, higher demand above forecast levels may lead to a requirement for additional network investment, in order to continue to meet mandated reliability requirements. This risk could potentially be addressed by making adjustments to the NSP's MAR within the period, using the uncertainty mechanisms discussed in section B.1.4. However, in the absence of these mechanisms, the NSP's profitability would fall.

NSP incentives in relation to tariff structures

Under a revenue cap, the NSP has an incentive to minimise the cost of providing its services, since the revenue it receives will remain unaffected, resulting in improved profitability.

Under a revenue cap, NSPs do not have an incentive to set efficient prices which reflect the underlying costs of supply, given that they receive the same, fixed amount of revenue over the regulatory control period irrespective of the prices they set.

The AER has previously commented that a revenue cap may provide incentives for inefficient pricing in some cases.[178] Because revenue is fixed, there is an incentive for DNSPs to increase prices above costs on price sensitive services. By doing so, demand for such services will fall, reducing the overall associated costs while maintaining a high rate of return.

However, the AER also stated that in practice it expects the incentives for DNSPs to set inefficient prices to be weak, because the majority of a DNSP's costs result from connections and augmentations to its network, and therefore, the incentive for a DNSP to decrease costs through pricing is likely to result in shifts away from other energy prices and towards fixed, peak, capacity and demand prices.[179]

An NSPs' incentive to provide demand management solutions are not undermined under a revenue cap, given that revenue received remains unaffected by reductions in demand. As revenue is fixed, DNSPs can benefit (at least in the short term) by implementing demand side management projects which reduce demand and therefore costs. This point has also previously been highlighted by the AER.[180]

Weighted average price cap (WAPC)

Mechanics

A WAPC form of price control is where the limit on price increases during a regulatory control period is set in terms of a weighted average of the prices charged by the NSP, with this changing over time based on a 'CPI-X' formula.

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178 AER, *Framework and approach – NSW*, June 2012, p. 58; AER, *Framework and Approach – Aurora Energy Pty Ltd*, June 2010, p. 64.

179 AER, *Framework and approach – NSW*, June 2012, p. 58.

180 AER, *Framework and approach – NSW*, June 2012, p. 60; AER, *Framework and Approach – Aurora Energy Pty Ltd*, June 2010, p. 64.

Under a WAPC, the 'X factors' are calculated at the time of the determination by setting the NPV of the allowed tariff revenue over the regulatory control period equal to the NPV of the forecast revenue requirement (calculated using the building block approach). In estimating future tariff revenue at the time of the determination, forecast quantities for each year are coupled with assumed prices for each tariff component.

- The assumed price for each tariff component is typically based on the current prices being charged by the NSP in the last year of the previous regulatory control period, coupled with an assumption of a constant tariff structure across the regulatory control period and assuming that the price control formula (eg WAPC) is met in each year.
- As a consequence, the assumed changes in tariffs across the period apply equally across all of the NSP's tariffs.
- The AER typically selects the X factors in years 2 to 5 of the regulatory control period, and then solves the NPV equivalence condition above in order to determine the X factor for the first year of the regulatory control period.

For NSPs subject to a WAPC, proposed prices are weighted and approved each year during a regulatory control period, provided that they comply with the WAPC formula. The NER[181] require the AER to set out the formula for the control mechanism as part of its Frameworks and Approach paper. However the typical form of WAPC formula applied is:

$$\frac{\sum\sum p^{t} \bullet q^{t-2}}{\sum\sum p^{t-1} \bullet q^{t-2}} \leq CPI - \mathrm{X}$$

Where p^t is the proposed price (for each tariff element) for the forthcoming year (ie, time period t), p^{t-1} is the price currently charged, and q^{t-2} is the actual outturn volume associated with that tariff element in the previous year (ie, time period t-2).

The WAPC formula above is based on information which is known at the time the formula is applied, ie, the prices proposed for the coming year, current prices and the quantities sold two years ago. The weights are typically based on quantities sold two years previously, as this is the most recent data available at the time of making the annual price determination. If estimates of quantities sold in the previous year (ie qt-1) or forecasts of quantities expected to be sold in the forthcoming year *ie, qt) were used, it would be necessary to also incorporate a correction mechanism to account for later differences between estimates/forecasts and actuals.

The NSP is able to rebalance tariffs (eg, increasing/decreasing some tariffs more than others) under the control, provided that the cap on the overall weighted average price is not breached, and subject to a separate rebalancing constraint set out in the NER, which is discussed further in section B.3.[182]

181 NER clause 6.8.1(b)(2)(ii).

182 NER Version 54, Clause 6.18.6 (c).

Impact on NSP revenues when demand changes

Under a WAPC, changes in actual demand compared to that forecast at the time of the determination directly affect the revenue received by the NSP over a regulatory control period.

The revenue earned by the NSP depends upon its approved tariffs and the actual quantities sold at those tariffs, in each year.

NSPs have an incentive to propose conservative (low) demand volumes at the time of the regulatory determination. The lower the assumed volumes, the higher are the tariffs required in order to result in the same expected tariff revenue, and therefore the lower the calculated X factors. The lower the X factors, the higher are the approved tariffs which the NSP is able to charge.[183]

If electricity demand falls below that forecast for a particular year, the NSP will earn less than their expected revenue for that year at the time of the regulatory determination. Conversely, if electricity demand is greater than forecast for a particular year, the NSP will earn more revenue than expected. This is illustrated in Figure B.3. An example of a decrease in demand relative to initial expectations is set out in Box B.3 below.

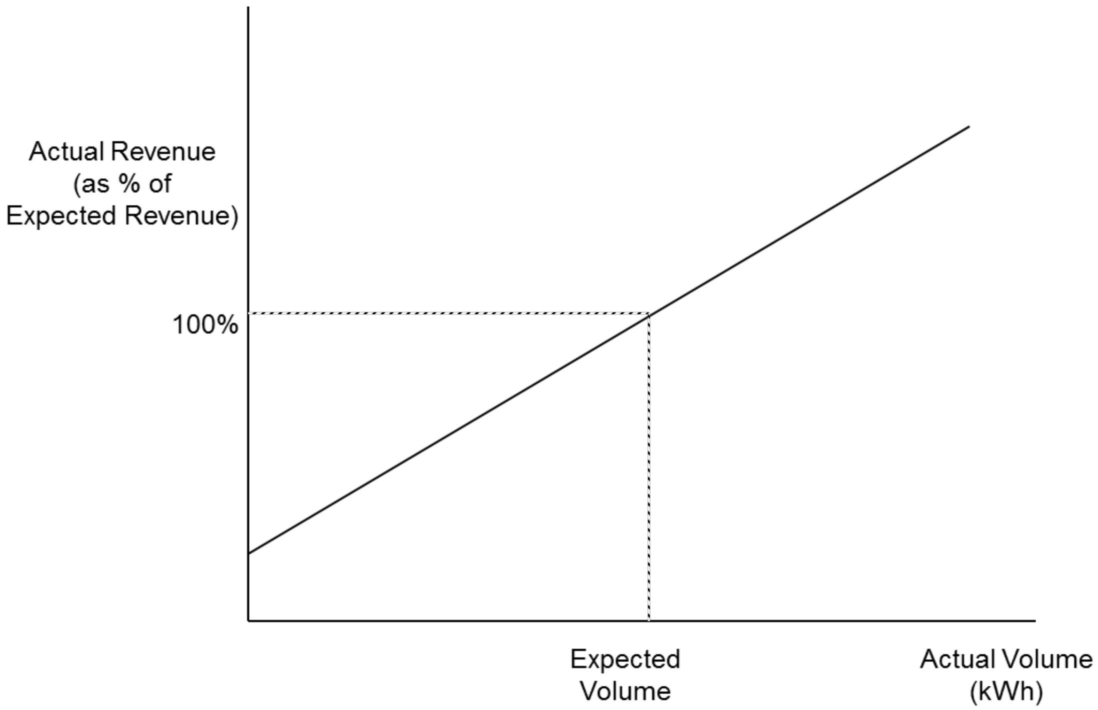
Overall, under the WAPC, NSPs bear the risk associated with changing volumes over the regulatory control period.

The AER has previously noted that the WAPC places volume risk during the regulatory control period on DNSPs. The AER also commented that it considers this is appropriate as 'DNSPs have influence over forecasts, prices and costs, and are therefore in the best position to manage volume risk'.[184]

183 Control mechanisms typically limit price changes between years to (CPI-X). The lower the X factor, the greater is the allowed increase in prices between years.

184 AER, *Framework and approach – NSW*, June 2012, p. 55; AER, *Framework and approach – ActewAGL*, June 2012, p. 43.

Figure B.3 WAPC: Difference between actual and expected revenues where actual volumes differ from expected volumes



Impact on NSP profit from demand changes

Under a WAPC, there is a direct link between the marginal revenue earned by the NSP and its tariff structure. If the NSP sells an additional unit, the marginal revenue it earns will be equal to the price applying to that extra unit. This link provides the NSP with an incentive to set their tariff structures to reflect their underlying cost structure, in order to minimise their profit risk. If tariff structures do not reflect the underlying cost structure, then the NSP will face profit risk as quantities change, since revenues and costs vary in different proportions.

For example, consider a NSP who levies a single rate tariff, which is comprised of a fixed component and a per kWh usage component. The NSP may choose to charge below cost for the fixed component, and above cost for the per kWh component, such that overall on the basis of forecast quantities it expects to cover its total costs.

Such a pricing strategy may satisfy the WAPC constraint. However, it will leave the NSP exposed to a higher degree of profitability risk than if it had set its tariffs to reflect its costs. For example:

- if actual kWh volumes sold are less than forecast, the NSP will not recover its total fixed charges overall, reducing its profitability; or
- conversely, if volume demanded grows more rapidly than forecast, the NSP's profitability would increase, as the increase in its kWh revenue would be greater than the increase in its variable costs.

Box B.3 provides an illustration of this situation, where there is a decrease in demand relative to forecast.

Overall, NSPs can reduce their exposure to profit risk by aligning tariffs and costs under a WAPC.

In the 'Frameworks and Approach' paper for the Victorian DNSPs, the AER stated that the WAPC form of price control allows the Victorian DNSPs to manage uncertainty in outturn volume by re-balancing their tariffs.[185] However in its later 'Frameworks and Approach' paper for the 2014-19 determination for DNSPs in NSW, the AER stated that a WAPC is unlikely to result in recovery of efficient costs, in part, because the bulk of costs are fixed.[186] Therefore, the total costs to a DNSP implied by low demand do not differ greatly from those implied by high demand. A WAPC regime takes the higher per unit cost under low demand into account by allowing DNSPs to charge higher prices in cases of low demand. However, this creates an incentive for DNSPs to provide unrealistically low demand forecasts at the time of the determination (securing high price caps) and subsequently receive inflated revenue when actual demand exceeds the forecast.

NSP incentives in relation to tariff structures

Theoretically, NSPs have an incentive to set their tariff structures to reflect their underlying cost structure under a WAPC as it minimises their profit risk. This is illustrated in Box B.3, for a situation of a decrease in demand relative to initial expectations. In practice, however, the AEMC has previously noted that NSPs do not always set cost reflective tariffs because:

- there are technical and policy restrictions on networks to price at cost reflective levels; and
- the link between volumes at peak times, higher costs and lower profits is not straightforward for a network business.[187]

Where the weights applied in the WAPC constraint are based on actual quantities sold two years previously (ie, q^{t-2}), NSPs also face an incentive to set prices with regard to how fast or slow demand for each of the different price components is growing.

NSPs can increase their overall revenue by increasing prices the most for those price components for which demand is growing at the fastest rate, given the weights in the WAPC formula are based on demand data that is two years old at the time of setting the current year's prices. If a NSP knows demand for a particular service is growing it has an incentive to increase the price charged for this service in the current year as it can increase its revenue received given that its actual revenue will reflect the actual quantity sold at the higher tariff, ie, $p^t.q^t > p^t.q^{t-2}$.

NSPs also have an incentive to keep prices constant (or to raise them more slowly) on those components where demand is falling, in order to limit the decline in expected overall revenue as a result of reducing demand for some services.

185 AER, *Framework and Approach – Citipower, Powercor, Jemena, SP AusNet and United Energy*, May 2009, pp. 67-68.

186 AER, *Framework and approach – NSW*, June 2012, p. 55.

187 AEMC, *Power of Choice Review – Final Report*, 30 November 2012, p. 215.

The AER has previously commented on these incentives. As part of its Frameworks and Approach paper for the 2014-19 determination for DNSPs in NSW, the AER noted the incentive for DNSPs to increase prices on services with increasing sales quantities and decrease prices on services with decreasing sales quantities, in order to earn revenue above forecasts.[188]

As noted above, in determining the X factors, the WAPC constraint (including lagged weights) is used by the AER in projecting changes in prices over the regulatory control period. However, the AER also assumes that there will be no change to existing tariff structures and the relativities between tariffs over the regulatory control period. In contrast, as part of the annual tariff approval process NSPs are free to rebalance tariffs and to increase some tariffs more than others, and have incentives to do so. As noted earlier. NSPs under a WAPC therefore have an incentive at the time of the revenue determination to under-state future demand levels (as more conservative demand forecasts will lower the X factor calculated), even through the WAPC formula uses lagged volumes to weight changes in prices over the period.

The AEMC notes that there is no straightforward alternative to the AER's assumption of constant tariff structures at the time at which it determines the X factors. The AER would have no firm basis for assuming a particular change in an NSP's tariff structures during the regulatory control period. In addition, if the AER were to adopt a particular tariff rebalancing assumption, this would alter the risks faced by the NSP where it did not then in practice adjust its tariffs to be consistent with the tariff structure assumed by the AER. As noted above, NSPs' incentives under a WAPC with lagged weights are affected not only by the potential to increase profits by increasing prices the most on the fastest growing tariff components, but also by their ability to manage the profitability risk they face where actual volumes differ from forecast volumes.

188 AER, *Framework and approach – NSW*, June 2012, p. 55.

Box B.3: Example of falling demand and profitability risk under a WAPC

Consistent with Box B.2 above, suppose a NSP has an annual fixed cost of $100/customer, a variable cost of $1/kWh and currently serves 1,000 customers with the expectation that annual demand will be 20MWh.

Suppose that the NSP chooses to set a tariff structure that is not aligned with its underlying cost structure. Specifically, assume the NSP chooses to do this by charging a fixed tariff of $70/customer and a variable tariff of $2.50/kWh. The NSP would expect to earn the following revenue and profit:

- Revenue: $120,000, ie, (1,000 customers x $70/customer) + (20,000kWh x $2.50/kWh); and
- Profit: $0, ie, $120,000 – [(1,000 customers x $100/customer) + (20,000kWh x $1.00/kWh)]

This tariff strategy exposes the NSP to profit risk if demand turns out to be lower than expected. For example, suppose that outturn demand is only 15MWh, the NSP would earn the following revenue and profit:

- Revenue: $107,500, ie, (1,000 customers x $70/customer) + (15,000kWh x $2.50/kWh); and
- Profit: -$7,500, ie, $107,500 – [(1,000 customers x $100/customer) + (15,000kWh x $1.00/kWh)]

Under a WAPC the shortfall in revenue is not made-up in later years by an adjustment to the price cap (in contrast to a revenue cap). As a consequence, the NSP would make a loss in this case.

This profit risk can managed if the NSP instead sets a tariff structure in-line its underlying cost structure, ie, a fixed tariff of $100/customer and a variable tariff of $1.00/kWh. When tariffs are in-line with costs, the NSP would expect to recover its costs under any demand volumes, ie:

If demand is 20MWh as expected, the NSP would earn the following revenue and profit:

- Revenue: $120,000, ie, (1,000 customers x $100/customer) + (20,000kWh x $1.00/kWh); and
- Profit: $0, ie, $120,000 – [(1,000 customers x $100/customer) + (20,000kWh x $1.00/kWh)]

If demand is lower than expected (ie, 15MWh), the NSP would earn the following revenue and profit:

- Revenue: $115,000, ie, (1,000 customers x $100/customer) + (15,000kWh x $1.00/kWh); and
- Profit: $0, ie, $115,000 – [(1,000 customers x $100/customer) + (15,000kWh x $1.00/kWh)]

The NSP therefore has an incentive to set their tariff structures to reflect their underlying cost structure under a WAPC as it minimises their profit risk.

The AER also expressed scepticism in relation to the operation of the incentives under a WAPC in practice. It noted that while the WAPC is supposed to provide theoretical incentives to set efficient prices, it did not consider that pricing outcomes have been efficient in practice across the NSW and Victorian DNSPs.[189]

Under a WAPC, the link between volumes sold and allowed revenue may act as a disincentive on NSPs to undertake demand management initiatives. Reductions in volumes reduce the revenues earned by the DNSP. Where the reduction in revenue does not also represent a reduction in the costs faced by the DNSP, it would also reduce their profitability. The AER has previously commented on this disincentive.[190]

The DMEGIS is intended to counter this disincentive, as discussed in section B.1.7, by allowing prices to be adjusted to reflect foregone revenue as a result of having undertaken (approved) demand management initiatives. The changes to the DMEGIS proposed by the AEMC in its *Power of Choice* review would further address this issue.

Average revenue cap

Mechanics

Under an ‘average revenue cap’ form of control (also known as a ‘revenue yield’ control), a cap is placed on the average revenue per kWh the NSP is allowed to earn per year. Average revenue is calculated as total revenue divided by total output, and so requires a homogenous unit of output in order for a ‘total output’ measure to be established, ie, kWh.

The average revenue per unit is typically calculated by dividing the allowable revenue calculated at the time of the determination by either a forecast kWh of output, or kWh output in previous years.[191] This average revenue is then allowed to vary throughout the regulatory control period on the basis of a ‘CPI-X’ formula.

The NSP must ensure that the average revenue per unit in a given year (calculated using proposed prices and forecast quantities for that year) is less than or equal to the maximum allowed average revenue per unit. This is represented by the following formula:

$$\sum \frac{p_t q_t}{q_t} \le \mathrm{Re}\,vYield_{t-1}(CPI - X)$$

Importantly, the amount of revenue earned on each *individual* unit (as opposed to the *average* revenue per unit) is not regulated. Therefore, the NSP has a degree of flexibility in setting individual tariffs within this control mechanism.

189 AER, *Framework and approach – NSW*, June 2012, p. 58.

190 AER, *Framework and approach – NSW*, June 2012, p. 60.

191 The AER is required to set out the exact average revenue cap formula to be applied in a determination in its framework and approach paper. For ActewAGL, the AER set out the following formula: $\sum \frac{p_t q_{t-2}}{q_{t-2}} \le \mathrm{Re}\,vYield_{t-1}(CPI - X)$

See: AER, *Matters relevant to the framework and approach for NSW and ACT DNSPs 2014-19*, February 2013, p. 10.

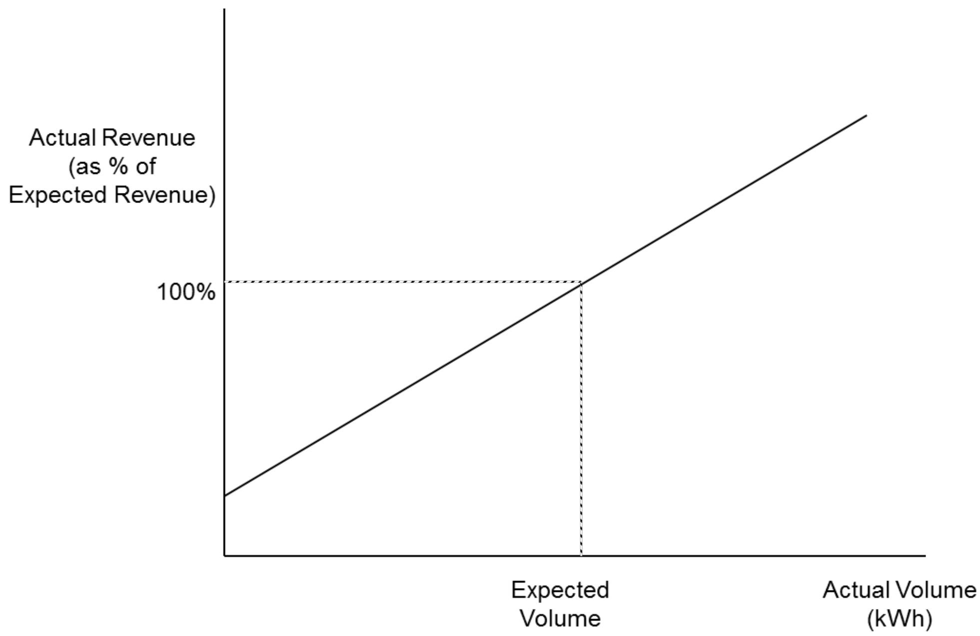
Impact on NSP revenues when demand changes

Changes in demand directly affect the revenue received by the NSP each year under a revenue yield form of control mechanism.

The revenue earned in a particular year by an NSP depends upon the actual tariffs applying and the actual quantities sold of each of the charging parameters. If electricity demand falls below that forecast for a particular year, the NSP will earn less than its expected revenue for that year. An example of a decrease in demand relative to initial expectations is outlined in Box B.3. Conversely, if electricity demand is greater than forecast for a particular year, the NSP will earn more revenue than expected.

Overall, under an average revenue control, NSPs bear the volume risk, since the revenue received for a particular year depends on the quantities sold. Figure B.4 below illustrates this.

Figure B.4 Average revenue control: difference between actual and expected revenues where actual volumes differ from expected volumes



Impact on NSP profit from demand changes

As outlined above, the revenue yield approach places volume risk on NSPs, with actual revenue varying with changes in demand. Given that costs are unlikely to be as strongly related to demand due to the presence of large fixed costs in transmission and distribution networks, it follows that NSPs also face profit risk under an average revenue cap, if outturn demand is different to forecast demand.

Under an average revenue cap, total revenues are determined in relation to all dimensions of tariffs, including fixed charges, demand charges and energy charges. In contrast, total quantities, are not determined in relation to all components of tariff structure, or to all cost components. Rather, total quantities represent a homogenous measure of total quantities, in kWh. This somewhat artificial definition of output masks the different dimensions of an electricity distribution service, and, as a result, the different unit cost characteristics of each dimension.

Since there is no necessary link between marginal revenues and marginal costs under an average revenue cap formula, there is a danger of systematic trends in cost and revenue drivers (such as a changes in demand conditions) leading to persistently lower (or higher) profits than expected.

NSP incentives in relation to tariff structures

Under the average price cap form of control mechanism, NSPs cannot manage profit risk through changes in their tariff structures. This is because it is the average amount of revenue per unit that is regulated, creating a mismatch between marginal revenues and marginal costs.

Instead, NSPs are provided with incentives to design tariff structures which do not necessarily reflect cost structures, but promote distribution of additional kWhs as this will increase their revenues.

Specifically, it is clear from the average revenue cap equation above that each additional unit attracts the per kWh allowance, regardless of the actual tariff applied to that unit. As a result, NSPs face incentives to increase the units of energy distributed by the lowest cost method (ie, so long as the marginal cost of the incremental unit does not exceed the average revenue allowance). Further, in those segments of the market where total demand can be increased at relatively low marginal cost, NSPs have an incentive to lower prices below economically efficient levels, in order to increase their overall profitability.

The link between volumes sold and allowed revenue may also act as a disincentive on NSPs to undertake demand management initiatives (as it reduces the revenue they are allowed to earn), and may encourage NSPs to expand volumes by non-price means. Again, the DMEGIS is intended to counter the disincentive to undertake demand management resulting from the associated reduction in revenues.

B.3 Impact of differences between forecast and actual demand on tariff structures

Summary

DNSPs determine the structure of network tariffs faced by retailers. As a consequence, it is the impact of differences between forecast and actual demand on DNSPs' tariffs which is of primary relevance for this review, rather than TNSP's tariff structures.

Under the NER, DNSPs are required to submit annual pricing proposals, which comply with a set of pricing principles set out in the NER. The NER also includes 'side constraints' which limit changes in the relativities between tariffs.

In theory, a WAPC form of control mechanism can provide incentives for DNSPs to set efficient tariffs, including to manage their volume risk where demand is falling compared with forecasts. However in practice this incentive may be offset by incentives to maximize revenues by increasing tariffs the most on the fastest growing components of demand, and limiting price increases on those elements where demand is falling, as well as by the side constraints between individual tariffs.

Under a revenue cap NSPs do not face incentives to improve the efficiency of their tariff structures, and may face incentives to adopt inefficient tariff structures, which limit volumes sold. However, again, in practice the impact of these incentives may be limited.

As part of its *Power of Choice* review, the AEMC has proposed a number of changes to the pricing principles in the NER, to provide better guidance on setting efficient and flexible network pricing structures, as well as resulting in a more robust consultation process around annual network tariff setting. These proposed changes to the NER would directly address the issue of providing efficient tariff structures in the face of uncertain future demand levels, and include:

- changes to the NER distribution pricing principles to provide better guidance for setting efficient and flexible network pricing structures;
- more robust consultation and verification applied to the annual network tariff setting process, including consulting on requested changes to the approved statement of network pricing structures;
- a new requirement for DNSPs to develop and consult with retailers and consumer groups on a statement of proposed network pricing structures as part of their regulatory proposals;
- possible changes to the network pricing side constraints, including the review of Clause 6.18.6(b) which prohibits price changes of greater than 2 per cent from one year to the next; and
- a requirement for the AER to publish a guideline for network tariff arrangements.

The previous section has highlighted how NSPs' profitability is affected by the choice of control mechanism applied to their tariffs, and the different incentives they are likely to have under different control mechanisms to move to efficient charging structures.

This section considers further the current NER provisions in relation to pricing, and in particular the annual price approval proves and the ability of NSPs to rebalance their tariffs during a regulatory control period. The focus of this section is particularly on distribution pricing, as it is DNSPs who determine the structure of network prices faced by retailers. This section also focuses on incentives for DNSPs in relation to their tariff structures where demand is falling relative to forecasts. SCER in its request for advice explicitly mentions the potential for improvements to the NER around annual network tariff setting in ensuring that consumers receive the benefits of sustained reductions in demand.

B.3.1 NER requirements for DNSP pricing

Under the NER, DNSPs are required to submit pricing proposals on an annual basis.

DNSPs' pricing proposals set out the proposed tariff classes for the upcoming regulatory year and the proposed tariffs and charging parameters that correspond to each of these tariff classes. They also include information, including demand forecasts, which supports assessment of the compliance of the DNSP's proposed tariffs with the applicable control mechanism.

Pricing proposals must be submitted within fifteen days of the publication of the distribution determination for the first regulatory year of a regulatory control period and at least two months before the commencement of subsequent regulatory years during the regulatory control period.[192] The AER is responsible for assessing and approving proposed prices before they go into effect.

Pricing proposals must comply with a set of principles set out in Clause 6.18.5 of the NER. These principles can be summarised as follows:

- the revenue of each price class must be greater than the incremental cost and less than the standalone cost of the service;[193]
- DNSPs must take into account the long run marginal cost (LRMC) for a network service in setting network prices;[194] and
- DNSPs must have regard to (i) transaction costs associated with the tariff, and (ii) whether retail customers of the relevant tariff class are likely to respond to price signals in setting network prices;[195] and
- where the above principles do not result in prices which recover expected revenue, the DNSP must adjust prices in a way that minimises distortion to efficient patterns of consumption.[196]

192 NER clause 6.18.2(a)(2).

193 NER clause 6.18.5(a).

194 NER clause 6.18.5(b)(1).

195 NER clause 6.18.5(b)(2).

In addition to the above principles, prices for standard control services must also comply with the 'side constraints' outlined in Clause 6.18.6 of the NER. These side constraints can be summarised as follows:

- the expected weighted average revenue to be raised from a tariff class for a given year must not exceed the corresponding expected weighted average revenue for the preceding year in that regulatory control period by more than the 'permissible percentage'; and
- the permissible percentage is calculated as the greater of:
  - the CPI-X limitation on any increase in the DNSP's expected weighted average revenue between the two regulatory years plus 2 per cent; and
  - CPI plus 2 per cent.[197]

The AER must approve a pricing proposal if it is satisfied that it (i) complies with rule 6.18 of the NER (including the pricing principles) and (ii) all forecasts associated with the proposal are reasonable.[198] If the AER is not satisfied with a proposal on this basis, it may require the relevant DNSP to amend and resubmit the proposal within 10 business days of the AER's notice, or make the necessary amendments itself.[199] If the DNSP fails to submit an amended proposal, or the amended proposal in unsatisfactory, the AER may also make the necessary amendments.[200]

In practice, the current pricing proposal process involves little consultation and does not require the AER to issue discussion papers or a formal final decision. The AER provides documentation only if it chooses to reject a DNSP's initial pricing proposal, in which case it issues a short determination outlining its reasons for rejection.[201]

B.3.2 NER requirements for TNSP pricing

As noted above, the AEMC's focus for this portion of the advice is primarily on the incentives for network pricing and rebalancing by DNSPs as demand changes, as it is DNSPs who determine the structure of network prices faced by retailers.

The NER requirements in relation to transmission pricing are set out in Part J of Chapter 6A. The NER provisions (and in particular the pricing principles for prescribed transmission services) are more prescriptive than those for distribution, and set out:

- a cost allocation process (base on 'attributable cost shares') for determining how the maximum allowed revenue for transmission services should be recovered across each category of prescribed transmission service (6A.23.2); and

196 NER clause 6.18.5(c).

197 NER clause 6.18.6(b)(c). The NER also sets out factors that are not to be considered in deciding whether the permissible percentage has been exceeded in a particular regulatory year.

198 NER clause 6.18.8(a).

199 NER clause 6.18.8(b).

200 NER clause 6.18.8(c).

201 Examples of rejected pricing proposals include *Powercor – Annual pricing proposal 2013* and *United Energy – Annual pricing proposal 2013.*

- within each transmission service category, an allocation process in relation to different connection points (6A.23.3), which incorporated both a locational and a non-locational component.

The NER also includes a number of price structure principles for transmission prices (6A.23.4). This includes that:

- prices for prescribed common transmission services must be on a postage-stamp basis; and
- Prices for recovering the locational component of providing TUOS services must be based on demand at times of greatest utilization of the transmission network and for which transmission investment is most likely to be contemplated.

In addition, the AER is required to make and publish guidelines ('the pricing methodology guidelines') relating to the preparation by a TNSP of a proposed pricing methodology.[202]

TNSPs submit their proposed pricing methodology to the AER alongside their revenue proposal, at part of the periodic regulatory determination process.[203] The AER is required to either approve or refuse to approve the proposed pricing methodology, and to provide the reasons for its decision.[204] The AER must approve the TNSP's proposed pricing methodology if it is consistent with the pricing principles set out in the NER, and complies with the requirements of the pricing methodology guidelines.[205]

DNSPs pass through the charges they face for transmission services to retail customers on the basis of the chapter 6 provisions for 'designated pricing proposal charges'.[206] Under the NER, 'designated pricing proposal services' are defined as any of:

- prescribed exit services;
- prescribed common transmission services; and
- prescribed TUOS services.

The amount to be passed on by DNSPs to retail customers must not exceed the estimated amount of the designated pricing proposal charges which the DNSP will face, adjusted for any under- or over- recovery of charges in prior years.

B.3.3 Impact of demand reductions on NSPs' tariff strategies

As discussed above in relation to the form of control mechanism, differences between forecast and actual demand will affect the amount of revenue recovered by NSPs, where they face a WAPC or an average revenue control.

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202 NER rule 6A.25.

203 NER clause 6A.10.1 (a).

204 NER clause 6A.14.1(8).

205 NER clause 6A.14.3(g).

206 NER clause 6.18.7.

Under a WAPC, if tariffs are not cost reflective (ie fixed and variable charges are not proportionally recovered by fixed and variable tariff components) changes in demand may result in over or under recovery of costs, and therefore changes in NSPs' profitability.

Where a proportion of fixed costs are being recovered by variable charges, the NSP will under recover its costs under a WAPC or average revenue cap form of control, if actual demand is less than forecast demand. Under recovery of costs occurs even when new network investment also falls, concurrently with falling demand. This is because NSPs must still recover the fixed cost of their existing networks, even where reductions in demand mean that they no longer require substantial new investment.

An ongoing reduction in electricity demand may lead NSPs to seek to modify their tariff structures, to address this profitability risk and to ensure that fixed costs continue to be recovered. This may be accomplished by rebalancing fixed and variable tariff components so that they accurately reflect the underlying breakdown between fixed and variable costs. An alternative may be the introduction of new fixed tariff components, such as demand charges related to the maximum MW consumed over a period. Increases in the charges associated with initial MWh consumption bands under inclining block tariffs may also have the same impact, by increasing the total amount paid by customers in relation to their base consumption levels.

The AEMC notes that Ausgrid (in its 2012-2013 pricing proposal) noted that it had decided to "transition its transmission tariffs to cost reflective levels," and that "the future uncertainty in Ausgrid's volume environment… highlights the need for Ausgrid to continue to improve the cost reflectivity of network tariffs."[207]

As discussed earlier, these incentives to adopt efficient tariff structures under a WAPC may in practice be offset by incentives to maximise revenue by increasing tariffs the most on the fastest growing components of demand, and limiting price increases on those elements where demand is falling.

In addition, the previous section noted that under a revenue cap NSPs do not face incentives to improve the efficiency of their tariff structures, and may face incentives to adopt inefficient tariff structures, which limit volumes sold. However, the AER has noted in this regard that:

> "In practice, the incentive for DNSPs to set inefficient prices under a revenue cap is likely to be limited. This is because the majority of a DNSP's costs result from connections and augmentations to its network. Therefore, the incentive for a DNSP to decrease costs through pricing is likely to result in shifts away from other energy prices and towards fixed, peak, capacity and demand prices." [208]

207 Ausgrid, *Network Pricing Proposal for the financial year ending June 2013, May 2012*, p. 6-7, 9.

208 AER, *Framework and approach – NSW*, June 2012, p. 58.

B.3.4 Findings and recommendations in the Power of Choice review

The AEMC's recent *Power of Choice* review has considered the current application of the network pricing principles in Chapter 6 of the NER. The AEMC has made a number of recommendations to amend the NER to improve the current annual tariff setting process. These recommendations are summarized in Box B.4, and discussed further in this section. We consider that the adoption of these recommendations would improve the ability of NSPs to adopt efficient and flexible tariff strategies, and would improve the level of consultation and understanding associated with changes in tariff strategies, including where prompted by sustained reductions in demand.

Box B.4: Recommendations in relation to the annual network tariff setting process in the Power of Choice review

The *Power of Choice* review suggests changes to the NER in order to facilitate the adoption of demand-side participation. These recommendations include:

- changes to the NER distribution pricing principles to provide better guidance for setting efficient and flexible network pricing structures;[209]
- more robust consultation and verification applied to the annual network tariff setting process, including consulting on requested changes to the approved statement of network pricing structures;[210]
- a new requirement for DNSPs to develop and consult with retailers and consumer groups on a statement of proposed network pricing structures as part of their regulatory proposals;[211]
- possible changes to the network pricing side constraints, including the review of Clause 6.18.6(b) which prohibits price changes of greater than 2 per cent from one year to the next;[212] and
- a requirement for the AER to publish a guideline for network tariff arrangements.[213]

Changes to distribution pricing principles

As part of the consultation process for the *Power of Choice* review, the AER and other stakeholders submitted that the existing pricing principles should be made more focused. The AER considered that the existing principles are not prescriptive enough to encourage network businesses to propose prices which accurately reflect peak demand impacts on costs.[214]

209 AEMC, *Power of Choice Review – Final Report*, 30 November 2012, p. 183.

210 Id., p. 181.

211 Id., p. 190.

212 Id., p. 189.

213 Id., p. 181.

214 Id., p. 183.

To address these concerns the AEMC has proposed as part of the *Power of Choice* review the following changes to the five existing pricing principles:

- Principle 1 requires that the revenue of each price class is greater than the incremental cost and less than the standalone cost of the service. The Commission considers that this range is extremely wide and that this principle should therefore be a final check on prices rather than the primary requirement;[215]
- Principle 2 requires DNSPs to take into account the long run marginal cost (LRMC) for a network service in setting network prices. Principle 2 does not specify the method to be used in calculating the LRMC. The AEMC believes that DNSPs often interpret the LRMC in a way that is not consistent with its theoretical underpinnings and therefore proposes that the Turvey approach be adopted as the standard LRMC calculation methodology;[216]
- Principle 4 requires that network prices be determined with regard to the ability of consumers to respond to price signals. The AEMC acknowledges the importance of considering customers' abilities to respond to price signals. However, the AEMC also recognises the risk that this provision will encourage DNSPs to shift a disproportionate share of their costs onto consumers with non-flexible retail tariff structures. To mitigate this risk the Commission recommends that Principle 4 be replaced by the following requirements:
  - "that the development of network prices take into account the likely impacts of pricing structures on consumers, and
  - take into account relevant consultation requirements on proposed price structures in the rules."[217]
- Principle 5 stipulates that where principles 1 through 4 do not result in prices which recover expected revenue, the DNSP must adjust prices in a way that minimises distortion to efficient patterns of consumption. The AEMC considers that the current working of principle 5 implies that a Ramsey pricing approach would be used for the recovery of residual distribution network costs. The *Power of Choice* review has identified several problems with the Ramsey approach and has recommended that a postage stamp charge approach be implemented instead.[218]

A more robust consultation framework

Several stakeholders in the *Power of Choice* review suggested that retailers and consumer groups should play a larger, more formal role in the network price setting process. Currently, stakeholders may take part in the setting of network tariffs during the regulatory determination process or the annual price setting process via stakeholder consultation on the DNSP's 'regulatory proposal' or 'annual pricing

215 Ibid.

216 Ibid.

217 Id., pp. 184 - 186.

218 Id., pp. 184 - 188.

proposal'. The AEMC considers that this involvement is limited and suggests that greater stakeholder participation would allow for improved regulatory verification that network tariffs comply with the NER.[219]

In order to facilitate greater consultation and review of pricing proposals the AEMC recommends the addition of a 'statement of proposed network pricing structures' to apply for the regulatory control period. Such a statement would be developed by each DNSP with the involvement of retailer and consumer groups and would be reviewed by the AER.[220]

The AEMC further notes that IPART has recently proposed two additional measures to enhance the consultation and review processes of pricing proposals. These include:

- new consultation requirements proposed which would focus on annual pricing proposals. IPART's proposed rule change is to be released following the publication of the *Power of Choice* review;[221] and
- changes to the timing for network businesses to submit pricing proposals so that retailers have sufficient time to review and incorporate network prices in their retail prices. These changes would include a 20 day time limit for the AER to review and approve price proposals. The AEMC considers that 20 days may not be sufficient for the AER to perform this duty.[222]

A statement of proposed network pricing structures

As part of its effort to expand consultation and review roles in the network price setting process, the AEMC recommended that DNSPs be required to publish a statement of proposed network pricing structures as part of their regulatory proposal. Such a statement would be developed with the input of retailers and consumer groups. Subsequent revisions to the statement would be consulted on with stakeholders and approved by the AER.[223]

To support the implementation of the statement of proposed network pricing principles the AEMC recommends that the AER specify the following as part of its consultation and information guideline:

- the consumer consultation to be undertaken as part of developing pricing structures statement that forms part of the distribution business regulatory proposal;
- the consumer consultation to be undertaken by a distribution business in updating its statement of expected price trends and pricing structures in its annual pricing proposal;

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219 Id., p. 190.

220 Ibid.

221 Id., p. 191. IPART's Rule Change Proposal is available at http://www.ipart.nsw.gov.au/Home/Quicklinks/IPART_Submissions_to_External_Reviews/IPART_Submission_-_Proposed_changes_to_Annual_Network_Price_Setting_Arrangements_-_September_2012

222 AEMC, *Power of Choice Review – Final Report*, 30 November 2012, p. 191.

223 Ibid.

- the information required to be provided regarding the consumer consultation to be undertaken by a distribution business in developing its statement of expected price structures as part its regulatory proposal; and
- the information required to be provided regarding any proposed changes to the network pricing structures contemplated in annual pricing proposals.[224]

Changes to the network pricing side constraints

Clause 6.18.6(b) requires that the expected weighted average revenue from each price class for a particular regulatory year must not exceed the corresponding expected revenue for that price class in the previous year by more than two per cent of the average price increase.[225] This side constraint serves to protect customers from price volatility. However, the AEMC considers that there is a risk that it could restrict a DNSP's ability to set cost reflective prices, especially as we move forward into an environment where the need for cost reflective pricing becomes more pronounced. The AEMC therefore recommends consideration of whether this provision is necessary.[226]

A guideline for network tariff arrangements

Several stakeholders requested a greater level of guidance on certain aspects of the network tariff arrangements. Consequently, the AEMC recommends that the AER develop and publish a guide that (i) provides a detailed description of how pricing principles are applied, and (ii) sets out the requirements of the network pricing structures statements and annual updating of DNSP pricing proposals.[227]

224 Ibid.

225 Id., p. 189.

226 Ibid.

227 Id., p. 181.

C Assessment of options

As discussed in Appendix B, the NER already incorporate a number of provisions which link allowed revenues to changes in demand, and which are intended to provide incentives for NSPs to make efficient investment decisions in the light of differences between forecast demand at the start of the regulatory control period and subsequent outturn demand (or revisions in forecast demand).

This Appendix outlines four additional options which could be adopted to further strengthen the link between efficient expenditure and changes in demand. A number of these options were proposed by stakeholders or have been raised in other market reviews.

Specifically, it discusses the following options:

1. an adjustment to the calculation of efficiency gains (losses) over the regulatory control period to remove the windfall impact associated with changes in demand. This approach has been suggested by Grid Australia in its submission to the Productivity Commission review into network regulation;
2. a 'revenue driver' approach to adjusting allowed revenues at the next determination. This approach was recommended by the AEMC in its advice to SCER on the cost recovery of mandated smart meter infrastructure[228];
3. the removal of under-utilised assets from the RAB. This approach was raised by EUAA in this review and was the subject of the *Optimisation of Regulatory Asset Base and Use of Fully Depreciated Assets* rule change submitted by the Major Energy Users (MEU) in November 2011 ; and
4. a project by project assessment of demand-driven capex at the time at which the capex is needed, to replace the current assessment of the total capex program over the five year regulatory control period. Versions of this approach has been considered by the Productivity Commission in its review into network regulation and been raised by AEMO in its submission to this review.

These four options are only briefly explained in this Appendix. Further detail would need to be developed before the options set out here would be suitable for implementation, and the AEMC notes that they could be complicated to apply in practice. It would also be necessary to consider the impact of these options on the existing incentives reflected in the NER, and the administrative costs for both the AER and NSPs.

The first three options apply a form of reconciliation (“true up”) to allowed revenues to account for differences between forecast and actual demand. While option 4 attempts to address the issue through decreasing the time gap between the decision on allowed expenditure and the need for investment.

A general difficulty with the above approaches is that they are highly dependent on the ability to link costs to specific changes in demand. This raises the issue of whether

228 AEMC, *Request for Advice on Cost Recovery for Mandated Smart Metering Infrastructure*, Final Report, 22 December 2010.

defining projects as "demand-related" projects is a realistic reflection of the drivers on network investments.

It is our understanding that many network investments are undertaken in response to several drivers (such as replacement of assets and the need to meet reliability standards), which need not all be related to demand. Also it will be common for NSPs to align the timing of replacement programs with augmentation and reinforcements needs of the network. It is important that NSPs do not become discourage from considering the most efficient way to manage all aspects of their business, including combining replacement and augmentation projects where appropriate.

All four options will affect the risks allocation between the NSPs and consumers. Some of them could transfer more of the risks associated onto consumers. Options which apply reconciliation ("true up") to allowed revenues to account for differences between forecast and actual demand, may actually increase the risks for consumers. This is because more of the risk associated differences in demand will now be pass onto consumers.

While the consumers might receive a larger benefit when actual demand is less than forecast demand, consumers are now exposed to more of the extra costs incurred if actual demand is more than forecast demand. This could negative affect the incentive on networks to control costs in the light of changing demand conditions because more of the risk has been passed onto consumers.

The first two of the above four options appear likely to be able to be accommodated under the existing NER, via the provisions which allow the AER to develop 'capital expenditure sharing schemes' and 'small scale incentive schemes'.[229] The current NER provide a process under which the AER could consult on and further develop these options, where it considers that they would be consistent with the capital expenditure incentive objective[230] and the National Electricity Objective. They also require the AER to consider the interaction of any proposed incentive schemes with the current incentive arrangements under the NER.

The second two options represent more substantial changes to the existing regulatory regime. We do not consider that these latter two approaches represent a proportionate response to the issues raised and would not be in the long term interest of consumers.

C.1 Adjustment to the calculation of efficiency gains/losses to remove windfall impact of changes in demand

Under the current regulatory arrangements, differences between forecast demand and actual demand which result in a change in the costs incurred by NSPs may result in "windfall" gains or losses accruing to NSPs. Such impacts have been labelled as windfall by Grid Australia, to describe circumstances where revenues vary due to factors that are largely outside the control of the NSP.

Such gains and losses arise both as a consequence of specific aspects of the regulatory approach (such as where a revenue cap form of control mechanism is adopted), as well

229 NER clauses 6.5.8A, 6.6.4, 6A.6.5A and 6A.7.5.

230 Set out in NER clauses 6A.5A(a) and NER 6.4A(a).

as potentially being a consequence of the introduction of a specific capex incentive mechanisms.

For example, if actual demand falls short of forecast demand, an NSP will likely need to undertake less augmentation expenditure than that reflected in allowed revenues at the time of the AER's regulatory determination. Any difference between the NSP's actual expenditure and allowed expenditure is treated as an efficiency gain under the NER, and the NSP is rewarded for that gain. However, in this circumstance, a portion of the savings is the result of lower costs due to lower demand (and therefore the need for the NSP to 'do less'), rather than representing a business-induced efficiency gain (where the business does the same, but for less cost). Therefore, a portion of the reward earned by the NSP represents a 'windfall gain'.

The opposite of this scenario is also possible where actual demand exceeds forecast demand and the NSP is required to incur additional expenditure as a result, which cannot be accommodated by making adjustments elsewhere in its expenditure programme. In this circumstance NSPs are penalised and therefore experience a windfall loss.

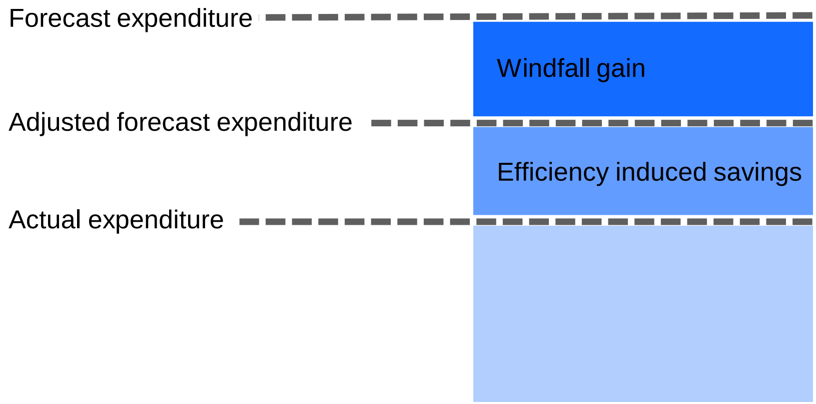
In its submission to the Productivity Commission's Draft Report on Electricity Network Regulation, Grid Australia proposed a mechanism to identify and neutralise the windfall gain/loss resulting from any difference between forecast and actual demand, as part of the operation of a capex incentive scheme.[231] Grid Australia's proposed mechanism is reproduced in Box C.1, and can be summarised as follows:

- prior to the start of the regulatory control period, forecast network augmentation is calculated using the best forecasts of demand available at the time;
- at the end of the regulatory control period, an adjusted forecast of expenditure is calculated by re-running the models that were used to calculate forecast augmentation using actual demand figures for the period; and
- business-induced efficiencies are calculated as the difference between actual augmentation expenditure and adjusted forecast expenditure.

This calculation is depicted in Figure C.1 below.

231 Grid Australia, (2012) *Electricity Network Regulation, Submission in response to Productivity Commission Draft Report*, 30 November 2012, pp. 18-19.

Figure C.1 Calculation of efficiency gain, excluding windfall gains/losses



Grid Australia's proposed approach would effectively correct for the windfall gain or loss component of an NSP's capex underspend or overspend, in calculating the reward or penalty to apply to an NSP under a capex incentive scheme.

A variant of the approach proposed by Grid Australia was adopted by the Essential Services Commission of Victoria (ESCV) in 2002. Specifically, the ESCV made an *ex post* adjustment to the capital and operating expenditure benchmarks for the regulated gas distribution businesses to reflect differences between forecast and actual customer connections, prior to the calculation of the rewards/penalties under the incentive carry-over mechanism.[232] The ESCV required the businesses to provide a per customer cost for new connections, which was then used to adjust the expenditure benchmarks at the end of the regulatory control period to reflect the difference between the forecast and outturn number of new connections during the period.

The AEMC notes that under the approach suggested by Grid Australia, NSPs would be provided no certainty at the start of the period over the adjusted expenditure forecast that would be used in making the correction for outturn demand at the end of the period. A modified version of Grid Australia's proposed mechanism, which would provide NSPs with a greater degree of certainty, could be developed as follows:

- the AER would establish a separate forecast capex allowance for a range of different demand scenarios at the start of each determination and would pick most credible capex/demand scenario for the determination based upon information at the time;
- at end of regulatory control period, the expenditure models would be re-run based upon actual demand and identify the most appropriate capex/demand scenario (the 'actual demand scenario'); and
- the windfall gain or loss would be calculated as the difference between the forecast demand scenario and the actual demand scenario. Revenue would be corrected to account for any windfall gain or loss.

The above approach would not be a form of menu regulation, as the NSP would still independently come up with its own forecasts and revenue proposal. However it

232 Grid Australia, (2013) *Electricity Network Regulation, Submission in response to Productivity Commission Draft Report*, 18 January 2013, p. 5.

would provide greater certainty to the NSP as to the adjusted forecast against which its actual expenditure would be assessed, in the event of a difference between forecast and actual outturn demand.

Under the existing NER, the AER is able to develop a capital expenditure sharing scheme,[233] defined as a scheme that provides an NSP 'with an incentive to undertake efficient capex during a regulatory control period'. The introduction of a mechanism to adjust the calculation of efficiency gains to remove the impact of windfall gains/losses associated with differences between forecast and actual demand would appear to fall within this definition.

In developing such a scheme, it would be open for the AER to consider the merits of mechanisms to adjust for differences between forecast and actual demand outcomes, along the lines of those discussed above. The AER would also consider the interaction of such an incentive scheme with the incentives already present under other elements of the existing regulatory frameworks, such as the contingent project mechanism.[234]

There are a number of issues with this approach that would have to be addressed before it could be applied. The obvious issue with this option are the reliance on modelling to determine the gains and losses. This could very much susceptible to debate about the assumptions leading to disputes between the NSP and the AER.

In addition, this option assumes that differences between forecast and actual demand are not within the control of the NSPs. However a network business could influence actual demand through its policies towards demand management and embedded generation. We note that this point applies more towards distribution businesses than transmission businesses.

Further analysis is required on how such an option would affect the incentives on networks and also the impacts on consumers. By including this adjustment to account for windfall gains or losses, the NSP may not have an incentive to get the demand forecast correct in the first instance. Furthermore, consumers will now be exposed to the risk of any increases in expenditure required if actual demand turns out to be higher than forecast demand. Under the current frameworks, NSPs are exposed to this extra cost.

Given that the AER can already consider the merits of these schemes, there would be no need for further changes to the NER in order to facilitate the adoption of this approach.

233 NER clauses 6.5.8A and 6A.6.5A.

234 As required under NER clauses 6.5.8A(d) and 6A.6.5A(d).

Box C.1: Grid Australia Proposed Mechanism to Minimise Windfall Gains/Losses[235]

In many incentive schemes, the reward or penalty that a regulated business receives for a change in performance is based on the difference between an ex ante forecast of the relevant performance metric and the result that is achieved. This approach is taken in the service target performance incentive schemes and operating expenditure efficiency benefit sharing schemes for both transmission and distribution. It is also implicit where a forecast of capex is included in the setting of a price or revenue cap.

However, transmission augmentation projects can be very large, and their timing critically affected by the forecast of demand, which is largely outside of the control of the transmission businesses. The implications of these factors is that applying a simple incentive scheme to transmission augmentation projects could deliver material windfall gains or losses (depending upon whether demand forecasts turn out to be too high or too low), which explains the preference of some of the consumer representatives for excluding such projects from incentive schemes.

An alternative approach to excluding augmentation projects from an incentive scheme is to attempt to remove the demand-related 'windfall' element from the rewards and penalties under the scheme. One approach could be:

1. include a forecast of augmentation expenditure in the capex that is included under the revenue cap that is based upon the best forecasts of demand available at the time. As discussed elsewhere in this submission, converting economically derived standards into a deterministic equivalent makes it more straightforward to link demand and expected capex needs;

2. at the end of the regulatory control period, re-run the models that were used to forecast augmentation expenditure using the actual demand that was observed over the period. This step could be made easier by the AER generating a number of forecasts of augmentation expenditure during the preceding review, with each scenario corresponding to different forecasts of demand, which is undertaken already by the TNSPs that use a probability-weighted average for capex across different scenarios for demand; and

3. calculate the business-induced efficiencies in augmentation expenditure by comparing the actual augmentation expenditure to the adjusted forecast. This would allow the demand-induced 'windfall' element to be removed from the measured change in efficiency, while still including (and thereby encouraging) savings in the cost of the project, or savings from being able to defer the project (including through undertaking demand side measures).

This last step would permit the 'windfall' element to be removed from the

235 Grid Australia, (2012) *Electricity Network Regulation, Submission in response to Productivity Commission Draft Report*, 30 November 2012, pp. 18-19.

reward or penalty that may have accrued during the previous regulatory control period, as well as permitting this to be excluded from any carry-over of capital-related efficiency benefits into the next regulatory control period. It is observed here that while undertaking such a project-by-project adjustment may appear at first sight to be complex or intrusive, the 'lumpiness' that characterises projects in the transmission sector makes such a project-by-project adjustment feasible. Moreover, the option would remain to remove particularly large or uncertainty projects from the revenue cap and treat them instead as a contingent project.

C.2 Use of revenue drivers to adjust allowed revenues

A revenue driver approach links an NSP's allowed revenue to actual outturn outcomes, via an adjustment to allowed revenues at the time of the next regulatory determination.

The application of a revenue-driver approach to demand-related expenditure would entail the revenue an NSP receives being linked to differences between forecast and actual demand measures (such as total consumption, peak demand and customer numbers) for a number of pre-defined, demand related expenditures. The NSP's allowed revenue would then be adjusted at the time of the next regulatory determination to reflect differences between outturn demand (or revised forecast demand) and the original demand forecast, for each of these expenditures, at pre-defined 'unit costs'. Revenue adjustments would be symmetrical; revenue would be removed at the next determination where demand is less than forecast and additional revenue would be included where demand is greater than forecast.

Under a revenue driver mechanism, adjustments to an NSP's allowed revenue are made only in relation to those cost elements directly affected by demand. The remainder of an NSP's allowed revenue would continue to be determined using the standard building block approach set out in the NER. Put another way, the adjustments to an NSP's allowed revenue to reflect differences between forecast and actual demand occur outside of the main building block calculation.

An example of how a revenue driver approach for demand might work in practice is outlined in Box C.2 below.

The purpose of the revenue driver mechanism is to ensure that NSPs remain neutral to differences between actual and forecast demand. The mechanism removes the financial impact on NSPs where actual demand deviates from forecast demand.[236] This would address any incentive on the NSPs to over-forecast demand in their regulatory proposals.

Incentives on NSPs to minimise costs under the revenue driver approach are maintained, as the revenue adjustment would be based on a standard measure of unit operating and capital costs, determined at the beginning of the previous regulatory control period, rather than the actual costs incurred by the NSP. Where the NSP was

236 This is in contrast to the impact on revenues under a WAPC, where changes in actual demand compared to forecast directly affect the revenue received by the NSP over a regulatory control period.

able to meet demand at a cost below the standard unit cost adopted, it would retain the benefit of this underspend in the following regulatory control period.

Box C.2: Example of Revenue Driver Approach

Under a revenue driver approach, the AER would set allowed unit costs for defined demand related outputs at the start of a regulatory control period in conjunction with the NSP. For example:

- $500 per residential connection; and
- $200 per kW of peak demand growth;

The AER would then agree on forecasts for each of the defined outputs over the regulatory control period in conjunction with the NSP, for example:

- 10,000 new residential connections; and
- 150MW of peak demand growth.

As part of the regulatory determination for the subsequent period, the AER would take into account actual outturn (or revised forecast) demand for these defined demand-related outputs, and would make a corresponding adjustment to the next period's allowed revenue.

For example, if demand was lower than expected and there were only 9,000 new residential customer connections and 120MW of peak demand growth, allowed revenue for the subsequent period would be reduced by $6.5 million.[237] Conversely, if demand was greater than expected and there were 12,000 new residential connections and 155MW of peak demand growth, allowed revenue for the subsequent period would be increased by $2 million.[238]

The AEMC proposed a similar revenue driver mechanism as part of its 2010 review of cost recovery for mandated smart meters infrastructure.[239] The AEMC Final Determination recommended an amendment to the NER to provide for a revenue adjustment at the time of the next distribution determination, to ensure that DNSPs remain neutral to any differences between the actual and forecast timing of a mandated smart meter roll-outs within a regulatory control period.[240] The adjustment was proposed to:

- remove any additional revenue earned by a DNSP, where a DNSP has rolled out smart meters and/or associated infrastructure slower than forecast in the previous distribution determination and allowed for in revenues for that period; and

237 ($500/residential connection x 1000 residential connections) + ($200/kW of peak demand growth x 30MW of peak demand growth), ignoring any present value adjustments.

238 ($500/residential connection x 2000 residential connections) + ($200/kW of peak demand growth x 5MW of peak demand growth), ignoring any present value adjustments.

239 AEMC, (2010), *Request for Advice on Cost Recovery for Mandated Smart Metering Infrastructure*. Final Report, 30 November 2010, pp. 6-7.

240 Id., pp. 19-20.

- compensate a DNSP for costs above allowed revenues where a DNSP has rolled out smart meters and/or associated infrastructure faster than forecast in the previous distribution determination.

As noted in the previous section, the ESCV also introduced a similar mechanism in 2002 for the regulated gas distribution businesses, which involved *ex post* adjustments to the capital and operating expenditure benchmarks to reflect differences between forecast and actual customer numbers. The ESCV required businesses to provide a unit cost for new customer connections, which was then used to adjust the expenditure benchmarks to reflect the difference between forecast and outturn new connections.[241]

A key implementation issue associated with a revenue driver approach in the context of managing the impact of differences between forecast and actual demand is the identification of unit costs and their relationship with changes in demand.

In the above cases where a revenue driver approach has been previously adopted or, it has been in relation to specific aspects of expenditure where unit costs are more easily definable. For example:

- the mechanism the ESCV introduced in 2002 for gas distribution businesses in Victoria targeted new customer connections; and
- the 2010 AEMC mechanism targeted the costs associated with the installation of smart meters.

Revenue drivers and standard unit costs associated with changes in network demand may not be as easy to identify. For example, augmentation costs to meet peak demand growth are likely to differ in different regions of an NSP's network, as well as between NSPs. In addition, NSPs in many cases combine the timing of replacement projects with network augmentation projects. Therefore, implementing a revenue driver approach to target fluctuating demand is not likely to be a simple task. If the wrong values are set, it will distort the NSPs incentives with regard to which projects to undertake.

Notwithstanding the above, it would be open to the AER under the current NER to consider the merits and practicalities of a revenue driver approach in considering whether or not to introduce a capital incentive sharing scheme, and the appropriate form of such a scheme. The objective of a revenue driver approach would be to provide an incentive for NSPs to undertake efficient capex during a regulatory control period, consistent with the definition in the NER of a capital expenditure sharing scheme. In addition, NER clauses 6A.5.4(5) and 6.4.3(a)(5) allow for "revenue increments and decrements (if any) for that year arising from the application of any [incentive scheme]" to be included in the building blocks. Conceptually, therefore, the revenue driver approach would be able to be implemented alongside the building block approach set out in the NER.

In addition, the AER is also able to consider whether to introduce a revenue driver approach under the current NER provisions which allow it to introduce 'small-scale incentive schemes' (NER clauses 6A.7.5(a) and 6.6.4(a) of the current NER). Such

241 Grid Australia, (2013) *Electricity Network Regulation, Submission in response to Productivity Commission Draft Report*, 18 January 2013, p. 5.

schemes are intended to provide NSPs with incentives to provide prescribed network services in a manner that contributes to the achievement of the national electricity objective.

As a consequence, the AEMC considers that the current NER already allow the AER to consider the merits of introducing an incentive scheme which would give effect to a revenue driver approach. No changes to the NER would therefore be necessary to facilitate this approach.

C.3 Removing under-utilised assets from the RAB

SCER's Request for Advice asks the AEMC to provide advice on whether amendments to the NER are needed to ensure that consumers receive the benefits of sustained reductions in demand. The Request for Advice flags that one possible mechanism to achieve this could be improvements to the AER's ability to consider utilisation of previously approved capex.

Under this approach, at the time of every regulatory determination the AER would review the utilisation of existing network assets and assess whether they are continuing to contribute to the provision of network services. Where there is a sustained reduction in demand, the utilisation of existing assets would be expected to fall, although the extent of this reduction will vary across different parts of the network.

Where the AER concluded that there were assets which were no longer contributing to the provision of network services, then these assets would be removed from the RAB and not used to determine allowed revenues for the forthcoming regulatory control period. The level of both allowed revenue and prices in the subsequent period would therefore be lower than they would have been in the absence of such optimisation, all else equal. The extent of the reduction in allowed revenues would reflect the return on (ie, WACC multiplied by the value of the removed asset) and return of (ie, depreciation) component associated with the assets being removed from the RAB. A potential variant would be to keep the asset in the RAB, but instead finance it at the cost of debt (rather than the WACC). Under this approach, allowed revenues and prices would also fall following optimisation, although to a lesser extent.

Where the RAB is subject to optimisation, consideration would need to be given to the additional risk implied for NSPs, and the appropriate mechanism to compensate NSPs for this risk – which would offset part of the reduction in allowed revenues.

Overall an optimisation mechanism would result in a reduction in allowed revenue and prices, where there is a sustained reduction in demand leading to underutilisation of network assets.

There are currently no general provisions in the NER for adjustment of the RAB at the time of a regulatory determination to account for the degree of utilisation of previously approved capex.[242] There is a limited exception for TNSPs, where assets which are dedicated to one transmission network user (not being a DNSP) or a small group of transmission network users, and where the value of the asset (or group of assets) at the

242 This is discussed in Appendix B.

start of the regulatory control period is greater than the indexed amount of $10m.[243] In this case, the AER may also determine a separate amount which is to be included in the building block revenue requirement to compensate the TNSP for the risk of the value of assets being removed from the RAB. To date this mechanism has not been used by the AER.

In contrast, the National Gas Rules (NGR) do include provisions for 'redundant' investment to be excluded from the RAB, where such investment no longer contributes to the delivery of pipeline services.[244] Where those assets subsequently contribute to the delivery of pipeline services, they are able to be added back into the RAB. Before requiring or approving a mechanism under this rule, the NGR require that the AER must take into account the uncertainty such a mechanism would cause and the effect the uncertainty would have on the service provider, users and prospective users.

Inclusion of optimisation of the asset base in the NER was proposed by the Major Energy Users Inc. (MEU) in a rule change request submitted to the AEMC in November 2011. The MEU's proposed rule would have required the AER to periodically review the existing asset base and exclude assets that are unutilised or underutilised from the RAB.[245] The MEU argued that asset base optimisation would prevent consumers from paying a rate of return to service providers for assets which are not utilised or are underutilised. This would include situations where sustained reductions in demand result in existing network assets being underutilised.

In its review of the MEU's proposed rule change, the AEMC determined not to make a change in the NER to permit optimisation of the RAB. The key considerations in reaching this conclusion were that such optimisation:[246]

- could increase the risk to service providers and therefore provide disincentives for future investment;
- could increase the complexity, costs and resourcing of the regulatory process; and
- would require the regulator to perform too detailed a role in approving a service provider's projects and plans.

In relation to the first point, the AEMC considered that *ex post* asset optimisation represents an increased risk to NSPs that assets may not be added to, or may be removed from, the asset base ('asset stranding'). This increased stranding risk would discourage service providers from undertaking efficient investment in an asset that appears to carry a risk of being under-utilised. Furthermore, investors would require a higher rate of return to compensate for the added risk of asset stranding. This may increase costs for customers.[247]

243 NER clauses S6A.2.3 and 6A.5.4(b)(7).

244 National Gas Rules, Part 9, Division 3, clauses 77 and 85.

245 AEMC, *National Electricity Amendment Rule 2012 – Rule Determination*, 13 September 2012, p. 1. The proposed rule also covered the replacement of fully depreciated assets which can be still be used.

246 AEMC, *National Electricity Amendment Rule 2012 – Rule Determination*, 13 September 2012, p. ii.

247 Id., pp. 19-20.

The Commission also considered that *ex post* optimisation would increase the complexity and costs of the regulatory process. The AER would be required to consider the degree of utilisation of every asset in the asset base. This would be time consuming and would require the use of data provided by the NSPs, which would need to be independently audited for accuracy. In addition, if optimisation were to be implemented, the regulator would need to develop detailed rules about how optimisation is to be undertaken, well in advance of its implementation.[248] The AEMC noted that these changes would increase the regulatory burden, and that the AER is already time constrained under the current regulatory process.

With respect to the third point, the AEMC determined that the introduction of asset optimisation would give the regulator an inappropriately high level of involvement in detailed decisions relating to a service provider's capital program.[249] Under the current form of regulation, a price or revenue cap is set at the start of the regulatory control period. Capex is not allocated to particular projects and it is up to the service provider to manage its projects and its business plan in the most efficient way. The AEMC considers that NSPs' access to information and their experience in running their networks put them in the best position to make detailed decisions about what expenditure is to be undertaken. *Ex post* asset optimisation allocates a role to the regulator in making these decisions, which potentially jeopardizes price outcomes and network reliability.

The AEMC also noted as part of its determination on the MEU rule change request that, unlike a competitive business, a regulated service provider has an obligation to invest to meet expected demand growth regardless of the likely risk, including the risk that expected demand does not eventuate.[250] Service providers are not compensated for this additional risk with a higher rate of return. The AEMC had regard to the limitations and obligations placed on service providers in its decision not to adopt asset base optimisation.

The AEMC has not seen any new analysis that would lead us to review the position reached in consideration of the earlier MEU rule change request. The AEMC notes that SCER requires that in proposing any amendments to the NER, the AEMC should have regard to the need to maintain stability and predictability in the regulatory regime, including ensuring sufficient capital investment certainty for infrastructure provision and the ability to obtain capital at reasonable rates. As noted above, the AEMC considers that the additional risk introduced into the regulatory arrangements as a consequence of allowing optimisation of the RAB would decrease the stability and predictability of the regulatory regime and provide disincentives for future investment.

C.4 Project by project assessment

A fourth alternative approach to addressing differences between forecast and actual demand outcomes would be to adopt a project by project approach to the assessment of NSPs' demand-related expenditure. This would be in contrast to the current

248 Id., p. 20.

249 Id., p. 7.

250 Id., p. 6.

approach of approving an expenditure allowance over the entire regulatory control period, and leaving NSPs to manage the risks of meeting their actual expenditure requirements within this allowance.

Such an alternative has recently been flagged by the Productivity Commission for the regulation of transmission networks, as part of its review on Electricity Network Regulation. Specifically, the Productivity Commission has suggested that all transmission projects (above a certain threshold) could effectively be considered as contingent projects, given the difficulty of predicting exactly when investments are needed, the lead times required for transmission investment and the difficulties of developing incentive regulation for projects that are out in the future.[251]

AEMO's submission to this review also advocated a variant of the project by project mechanism for all material augmentation capex. Under this option, all material augmentation capex (above the regulatory investment test threshold of $5m) are moved out of the 5 yearly regulatory reset process and into a modified contingent projects regime. Instead the regulatory investment test process will be applied to determine the most efficient project based upon the most recent demand forecasts. The most efficient project will be submitted to the AER for approval.[252]

A project by project assessment would involve an ex ante evaluation of each demand-related project proposed by an NSP. The aim of such an approach would be to lessen the uncertainty associated in forecasting an efficient level of demand-related expenditure at the beginning of a regulatory control period, and to instead assess individual projects closer to when the investment is actually required.

At a high level, a project by project assessment could operate as follows:

- an NSP would include a range of demand related projects as part of each regulatory determination process that may be required, depending on outturn demand;
- a demand related 'trigger event' would be defined for each of these projects as part of the regulatory determination process;
- if the trigger event occurs within a regulatory control period, the NSP would put forward cost estimates for the particular investment(s) to the AER; and
- the AER would review the costs proposed by the NSP and amend its revenue determination to include the revenue required for each approved project.

Variants of the above approach could include excluding all demand-related expenditure from the five yearly regulatory process, and instead making ad hoc determinations in relation to specific projects, as and when they occur.

Overall, a project by project mechanism could operate in a similar manner to the current contingent project mechanism. However, a project by project assessment would

251 Productivity Commission, (2012), *Inquiry into Electricity Network Regulatory Frameworks*, Transcript of Proceedings at Canberra, 6 December 2012, p. 303.

252 Under AEMO proposal, current arrangements will continue to be applied to existing network assets including replacement and refurbishment, and any augmentation projects under fall under the RIT threshold.

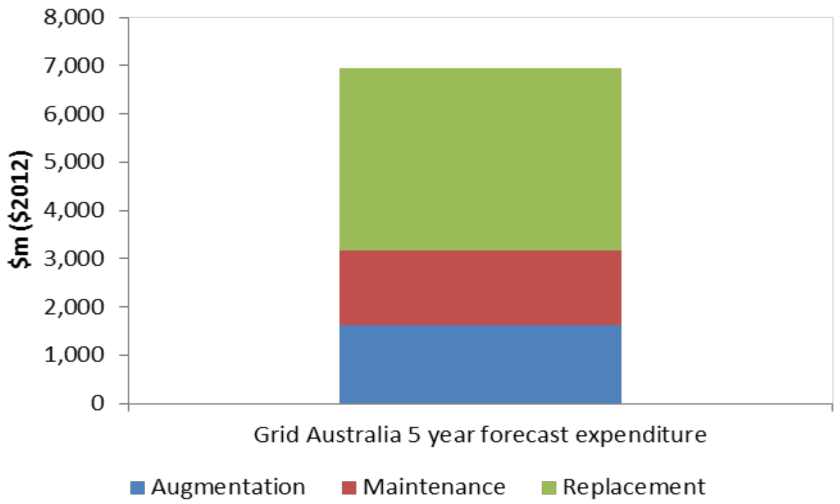
take the majority (or even all) of the NSP's demand related projects out of the general incentive regime. This is in contrast to the contingent project mechanism, which covers only the largest and most uncertain projects. The AEMC has previously noted that the substantial threshold for contingent projects means that these can only be used for larger projects, and that this is important in preserving the effectiveness of incentives under the ex-ante revenue allowance approach.[253]

In addition, given that there may be a combination of drivers for many network investments (such as demand growth and replacement), a project by project assessment mechanism would also be likely to capture projects which are not only demand-related.

A project by project assessment may be more easily adopted for demand-related transmission investments, given that transmission investments are typically large and their timing can be critically affected by forecast demand. A project by project assessment may be more difficult to apply to distribution networks, which are typically defined by a larger number of smaller investments with several drivers (demand growth, customer connections, replacement), and by expenditure relating to programs rather than discrete projects.

However, in addition to demand-related augmentation capex, TNSPs also undertake a large amount of non-demand related expenditure, ie, 'recurrent expenditure'. For example, in its submission to the Productivity Commission Draft Report on Electricity Network Regulation, Grid Australia stated that replacement and maintenance expenditure made up approximately 76 per cent of Grid Australia's total forecast five year costs, as depicted in Figure C.2. This expenditure may be less suited to a project by project assessment approach, given that the nature and timing of this expenditure is likely to be better known at the time of regulatory determinations and is not subject to outturn demand levels.

Figure C.2 Grid Australia Five-Year Forecast Expenditure, ($m, $2012)



Source: Grid Australia, (2013) Electricity Network Regulation, Submission in response to Productivity Commission Draft Report, 18 January 2013, p. 10.

253 AEMC, *Draft Rule Determinations, Draft National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, August 2012, p. 195.

The AEMC considers that a major failing of a project by project assessment approach is that it is a more administratively demanding mechanism, which provides substantially less scope for the application of incentive mechanisms to achieve cost efficiencies.

A project by project assessment would involve the AER having to assess the need for and expenditure associated with each demand-related project. Where a substantial number of projects are subject to such project by project assessment, it would be likely to increase the overall time needed by the AER to undertake the assessments. As a result, there could be a risk of delay in project construction as a consequence of requiring a project by project assessment. Conversely, the AER may have to start such an assessment further in advance of when the project is expected to be needed, re-introducing the scope for there to be subsequent changes in demand forecasts, and so reducing the value of the project by project approach as a mechanism to address such demand uncertainty.

A project by project assessment also represents a move away from incentive-based regulation towards a cost of service model. As noted above, a project by project assessment takes the majority (or all) of the NSP's demand related projects out of the incentive regime. While the AER could provide incentives for individual investments under a project by project assessment (as is currently done with contingent projects), the overall scope to apply incentives to NSPs' expenditure to ensure that they are undertaken at lowest cost is reduced.

A project by project type mechanism would also mean subjecting both NSPs and electricity consumers to a greater degree of annual pricing uncertainty and variability.

In addition, there would also be a risk that the AER could effectively become the decision maker on whether specific projects go ahead. It would not be appropriate for a regulator to be in this position, as they are not exposed either to the commercial risks or the reliability obligations faced by the NSPs.

Also project by project assessments assumes that it is possible to separately identify capex projects which are solely driven by increase in forecast demand. We also note that these types of approaches takes away any ability or incentive for a network to try and manage within its overall revenue for augmentation projects, including re-prioritising between years or between different types of expenditure. The work for the network regulation rule change indicated that NSPs did undertake such re-prioritisation.

For these reasons, we don't consider that a general move towards project by project assessments would be consistent with promoting the National Electricity Objective. The AEMC does not therefore consider that the adoption of a project by project assessment approach would be a proportionate change to the current incentive-based regulatory frameworks.