Opex and the Efficiency Benefit Sharing Scheme

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1. Introduction

I have been asked to prepare this report by ActewAGL Distribution (ActewAGL). The context for my report is the Australian Energy Regulator's (AER's) draft decision in relation to the distribution determination applying to ActewAGL for the period commencing on 1 July 2014 through to 30 June 2019 (the draft decision).[1]

ActewAGL has asked that I address a number of questions concerning the relationship between the operating expenditure (opex) allowance that is to be determined in the AER's distribution determination, and the Efficiency Benefit Sharing Scheme (EBSS) applying in relation to the immediately prior regulatory period. ActewAGL's instructions to me are attached as Annexure A to my report. For ease of exposition, I also set out the four specific questions I have been asked to consider in section 2 of this report.

1.1 My experience and expertise

I am a founding Partner of the economic consulting firm, HoustonKemp. For the twenty five years prior to establishing HoustonKemp, I was a consulting economist with NERA economic consulting, where I held the position of Director for sixteen years. Over that period I have accumulated substantial experience in the economic analysis of markets and the provision of expert advice and testimony in litigation, business strategy and policy contexts. I have developed that expertise in the course of advising regulators, corporations and governments on a wide range of competition, regulatory and financial economics assignments.

I have testified on these matters on numerous occasions before arbitrators, appeal panels, regulators, the Federal Court of Australia, the Competition Tribunal and other judicial or adjudicatory bodies.

My industry sector experience spans aviation, beverages, building products, e-commerce, electricity and gas, grains, insurance, medical waste, mining, payments networks, petroleum, ports, rail transport, retailing, scrap metal, securities markets steel, telecommunications, thoroughbred racing, waste processing and water.

In relation to the economic regulation of the energy sector in particular, in 2004 I was one of three members of an expert panel retained by the Standing Committee of Officials of the then Ministerial Council on Energy to advise on the appropriate specification of a national electricity objective, for inclusion in the then proposed national electricity law. Separately, in December 2005 I was appointed to an expert panel convened by the Minister for Industry and Resources, the Hon Ian Macfarlane, to prepare a report for the Ministerial Council on Energy on the harmonisation of the price determination elements of the access regimes for electricity and gas network services. The expert panel provided its report in April 2006, and many of its recommendations form the basis for the current framework of national electricity laws and rules.

I attach a copy of my curriculum vitae as Annexure B.

In preparing this report, I have been assisted principally by two colleagues, Brendan Quach and Oliver Nunn. Notwithstanding this assistance, the opinions in this report are my own and I take full responsibility for them.

1.2 Structure of this report

My report is structured as follows:

- in section 2 I explain the context for my report and set out the questions I have been asked to address;

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[1] Australian Energy Regulator, *Draft decision, ActewAGL distribution determination 2015-16 to 2018-19*, November 2014

- in section 3, I assess the incentives on ActewAGL to identify and implement opex efficiencies during the 2009-14 control period, and consider whether those incentives were sufficient to elicit ActewAGL to reveal its efficient level of opex;

- in section 4 I provide an assessment of the implications of adjusting a distribution network service provider's (DNSP's) base year opex on the basis that it is inefficient relative to its peers; and

- section 5 concludes my report.

I confirm that in the course of preparing this report, I have been provided with a copy of and read, understood and complied with Federal Court of Australia Practice Note CM7, entitled Expert Witnesses in Proceedings in the Federal Court of Australia (the Practice Note). My declaration, made in accordance with clause 2.2 of the Practice Note, is contained at the end of my report, as section 6.

2. Context for Report

In this section I explain the context for my report and set out the questions that I have been asked to address by ActewAGL.

2.1 National Electricity rules

The national electricity objective (NEO) is the foundational reference point for decisions made by regulators under the National Electricity Law and its accompanying rules. The NEO states that:[2]

> The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –
>
> (a)   price, quality, safety, reliability and security of supply of electricity; and
>
> (b)   the reliability, safety and security of the national electricity system.

The fundamental architecture of the NEO has been developed by reference to the promotion of efficiency, in the 'investment in', 'operation' and 'use of' electricity services. I explain below that these references correspond to dimensions of efficiency that are widely understood and accepted by economists. The references to such efficiency being 'for the long term interests of consumers..' and then 'with respect to..' a number specified dimensions of an electricity services serve to clarify that:

- the ultimate beneficiary of such efficiency is consumers;
- the relevant timeframe over which the efficiency objective should be interpreted is the long term; and
- the particular dimensions of electricity network services to which the efficiency objective should be directed, ie:
  - > the price, quality, reliability, and security of supply; and
  - > the reliability, safety and security of the national electricity system.

 'Efficiency' is a term of art in economics and is widely accepted by economists as having three distinct dimensions; namely:

- **productive efficiency**, which is concerned with the means by which goods and services are produced and is attained when production takes place with the least cost combination of inputs;
- **allocative efficiency**, which is concerned with what is produced and for whom, and is attained when the optimal set of goods and services is produced and allocated for use so as to provide the maximum benefit to society; and
- **dynamic efficiency**, which is concerned with society's capacity to achieve the efficient production and allocation of goods and services over time, in the face of changing productivity and/or technology (which reduces the cost of production and alters the optimal mix of inputs), and the changing preferences of consumers, which alters the good and services that are desired the most by consumers.

Each of these dimensions of efficiency is explicitly recognised by the architecture of the NEO. By way of explanation:

- the reference to efficient 'investment in' and 'operation of' electricity services refers to the productive dimension of efficiency, ie, the NEO will be promoted if decisions made by reference to it promote the supply of electricity services using the least cost combination of both capital and operating inputs;

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[2] Section 7, National Electricity Law

- the reference to efficient 'use of' electricity services refers to the allocative dimension of efficiency, ie, the NEO will be promoted if decisions are made that give rise to a level and structure of prices that both recover the cost of making electricity services available and maximise the extent to which consumers are able to purchase them at prices no greater than the benefit they derive from that decision; and

- the reference to efficiency in 'investment in' and for the 'long term' interests of consumers refers to its dynamic dimension, ie, the NEO will be promoted if decisions are made that give greater weight to long term productive and allocative efficiency considerations, as distinct from immediate or near term efficiency outcomes.

Importantly, the reference to the 'long term' interests of consumers and the reduced emphasis it implies for short term considerations underlines that the application of frameworks for economic regulation involves the need to make trade-offs between competing objectives. By way of example, the potential for short and long term efficiency objectives to be in tension with each other arises when a decision that may have the effect of increasing short term allocative efficiency (such as, by forcing a substantial reduction in consumer prices), is not consistent with the achievement of long term productive or allocative efficiency – because it threatens the sustainability of a service provider's operations or its efficient future investment plans.

To summarise, the NEO is structured so as to encapsulate all three dimensions of efficiency that are familiar to economists, ie, productive, allocative and dynamic. As a matter of principle, efficiency can be assessed in both static (at a particular point in time) and dynamic terms (over the future course of time). However, by its reference to the 'long term' interests of consumers, the NEO is structured so as to clarify that the balance of emphasis is to be given to the long term, dynamic dimension of efficiency.

2.2 Opex incentives for ActewAGL over the 2009-2014 period

Under the regulatory framework applying over the 2009-14 period, ActewAGL had a strong incentive to improve the efficiency of its opex. The framework was deigned to operate so that any resulting gains (or losses) relative to the benchmark opex allowance set by the AER in 2009 would be shared with ActewAGL's customers. The incentives on ActewAGL to improve the efficiency of its opex during this period arose from three different factors, which have been described by the AER as being that:[3]

(1) The AER will not claw back any differences between forecast and actual opex that arise during a regulatory period.

(2) The AER will use historical opex information when determining whether the forecast opex proposed by a DNSP for the next regulatory period is efficient; and

(3) The EBSS [efficiency benefit sharing scheme].

The efficiency benefit sharing scheme was published by the AER in 2008 (the 2008 EBSS), and is mechanism designed to reward or penalise a network service provider (NSP) for outperforming its forecast opex allowance during each regulatory price period. In particular, the 2008 EBSS – when combined with the 'no claw back' principle and the use of historic or revealed cost information to set the opex allowance for the following regulatory period – ensures that the rate of retention of any efficiency gains or losses is *invariant as to the timing* at which those gains/losses occurred. Further, the EBSS is designed to share those gains and losses:[4]

approximately 30:70 between the DNSP and distribution network users respectively.

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[3] AER, *Electricity distribution network service providers | Efficiency benefit sharing scheme*, June 2008, page 3.

[4] AER, *Electricity distribution network service providers | Efficiency benefit sharing scheme: Final decision*, June 2008, page 17. I note that the AER rejected a proposal by CitiPower and Powercor to lift the share of any gains or losses retained the DNSP.

The EBSS was specifically designed to counteract the incentive that otherwise exists for a firm operating under a fixed term price cap to delay the introduction of efficiency or cost savings initiatives that may be available towards the end of any regulatory period. By ensuring that the regulatory arrangements impose a constant incentive to make savings, DNSP has no incentive to delay the implementation of efficiency enhancing measures on the basis that the regulatory consequences make reduce the benefits that would otherwise arise.

However, the EBSS can only deliver such a constant incentive if it is combined with the determination of an opex allowance in the following regulatory period primarily by reference to the revealed or outturn costs of the DNSP for the prior period. This point was explicitly acknowledged by the AER, which stated:[5]

> In order for the EBSS to provide a continuous incentive, the AER considers forecast opex in the following regulatory control period should be based on actual opex in either the penultimate or antepenultimate regulatory year in the current regulatory control period.

2.3   Changes arising out of the Better Regulation review

In November 2012 the Australian Energy Market Commission (AEMC) completed the Economic Regulation of Network Service Providers Rule Change.[6] This rule change required the AER to develop and publish a series of guidelines on its approach to regulating network service providers (NSPs), including in relation to:

- the incentive arrangements for opex, ie, the EBSS; and

- the approach the AER will use to assess opex forecasts.

The guidelines for these two issues were completed in November 2013 as part of the AER's Better Regulation program.

The Better Regulation review did not result in any substantial change to the 2008 EBSS that was already in place. The only notable changes were those associated with:

- allowed adjustments and exclusions – with the new EBSS no longer excluding nominated 'uncontrollable' cost categories;[7] and

- the introduction of an adjustment to the EBSS carry forward amounts to ensure that any one-off adjustments to the base year opex amount were revenue neutral to the NSP.[8]

Further, the AER indicated that the EBSS did not need to be adjusted for the effects of a base year adjustment,[9] although it did state that:[10]

> In the unlikely event a NSP's revealed costs have no bearing on its opex allowance for a subsequent period we will consider not applying the EBSS reward (penalty) accrued in the first period to ensure the NSP does not retain more than 100 per cent of the efficiency gain (loss).

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[5] AER, *Electricity distribution network service providers | Efficiency benefit sharing scheme: Final decision*, June 2008, page 9.

[6] AEMC, *Economic Regulation of Network Service Providers and Revenue Regulation of Gas Services, Final Position Paper*, 2012.

[7] AER, *Better Regulation | Explanatory Statement | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, page 25.

[8] AER, *Better Regulation | Explanatory Statement | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, pages 20-22.

[9] AER, *Better Regulation | Explanatory Statement | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, page 31.

[10] AER, *Better Regulation | Explanatory Statement | Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, page 31.

However, in contrast the Better Regulation review of the means by which the future period opex allowance would be developed foreshadowed potentially substantial changes. In particular, the AER stated its preference for:[11]

> …. a 'base-step-trend' approach to assessing most opex categories.

The AER indicated that the base-step-trend assessment approach would result in a forecast of opex in year t as follows:[12]

$$Opex_t = \prod_{i=1}^{t}(1 + rate\ of\ change_i) \times (A_f^* - efficiency\ adjustment) \pm step\ changes_t$$

where:

- *rate of change$_t$* is the annual percentage rate of change in year *t*;

- A_f^* is the estimated actual opex in the final year of the preceding regulatory control period

- *efficiency adjustment* is the difference between efficient opex and deemed final year opex;

- *step changes$_t$* is the determined step changes in year *t*.

In assessing base year opex the AER state that:[13]

> The 'revealed cost' approach is our preferred approach to assessing base opex. If actual expenditure in the base year reasonably reflects the opex criteria, we will set base opex equal to actual expenditure for those cost categories forecast using the revealed cost approach …..

> We intend to not rely on the expenditure of a particular base year when we identify material inefficiencies in that expenditure. In this case, we may adjust the base year or substitute an appropriate base year. When determining whether to adjust or substitute base year expenditure, we will also have regard to whether rewards or penalties accrued under the EBSS will provide for the DNSP and its customers to fairly share efficiency gains or losses.

The AER identified two reasons for making adjustments to base year opex; namely, that:

1. a NSP's recurrent expenditure is inefficient compared to its peers

2. a NSP's base year expenditure is not reflective of efficient recurrent expenditure due to a one-off factor in the base year

Adjustments of the second form identified by the AER – the existence of non-recurring opex costs in the base year – does not change the nature of extent of the incentive arrangements existing under the 2008 EBSS. However, the same cannot be said in relation to the first form of adjustment. In section 4 I show that, by shifting away from adopting an NSP's revealed recurrent expenditure as the basis for its future opex allowance – such as through the imposition of benchmark-based judgement as to the degree of inefficiency of recurrent expenditure – will fundamentally undermine the incentives otherwise designed to achieve the objectives of the EBSS.

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[11]   AER, *Better Regulation | Explanatory Statement | Expenditure Forecast Assessment Guidelines for Electricity Distribution*, November 2013, page 31.

[12] AER, *Better Regulation | Explanatory Statement | Expenditure Forecast Assessment Guidelines for Electricity Distribution*, November 2013, page 31.

[13] AER, *Better Regulation | Explanatory Statement | Expenditure Forecast Assessment Guidelines for Electricity Distribution*, November 2013, pages 31-32.

2.3.1   Role of benchmarking in the regulatory process

The AER's proposal to apply the results of benchmarking analysis in its assessment of a distribution network service providers' opex allowance has evolved over time. Initially, the AER stated that:

> 'While we examine revealed costs in the first instance, we need to test whether DNSPs responded to the incentive framework in place. For this reason, we will assess the efficiency of base year expenditures using our techniques, beginning with the economic benchmarking and category analysis, to determine if it is appropriate for us to rely on a DNSP's revealed costs. That is, whether the DNSP's past performance was efficient relative to its peers and consistent with historical trends.'[14]

This statement suggests that the role of economic benchmarking would be to inform a threshold decision by the AER as to whether a DNSP's outturn opex performance can be classed as efficient, or inefficient. Reinforcing this, the AER had earlier stated that:

> '…there may be some circumstances where it is appropriate to adjust base opex to remove any identified inefficiencies. For example, if an NSP is not responding to the incentive to reduce opex to the efficient level the revealed cost approach will not provide a forecast of efficient opex. … Applying the revealed cost forecasting approach to an inefficient operator will produce an opex forecast that does not meet the opex criteria. Further, applying revealed costs would reward such firms for their historic inefficiencies.'[15]

In its final decision on the expenditure forecast guideline, the AER further stated that:

> 'We are likely to use economic benchmarking to (among other things):
>
> 1. measure the rate of change in, and overall efficiency of, NSPs. This will provide an indication of the efficiency of historical expenditures and the appropriateness of their use in forecasts.
>
> 2. develop a top down total cost forecast of total expenditure.
>
> 3. develop a top down forecast of opex taking into account:
>
>   - the efficiency of historical opex
>   - the expected rate of change for opex.'[16]

These statements indicate that economic benchmarking was to play a pivotal role in the AER's assessment of DNPS's expenditure, and the efficiency of that expenditure. In particular, the AER's statements suggest that economic benchmarking would initially inform a view as to whether a business is or is not 'responding to incentives'. In the event that a DNSP was deemed not to be responding to incentives, the AER proposed that it would establish its own, benchmark opex allowance.

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[14] AER, *Better Regulation: Draft Expenditure Forecast Assessment Guideline for Electricity Distribution*, August 2013, page. 7.

[15] AER, *Interaction between the EBSS and Opex Forecasts*, May 2013, page 1.

[16] AER, *Better Regulation | Explanatory Statement | Expenditure Forecast Assessment Guideline*, November 2013, pages 78-79.

2.4   Changes to the opex arrangements proposed in the draft decision

In November 2014 the AER published its draft decision, which substantially altered the anticipated opex arrangements for ActewAGL.[17] In particular, the draft decision:[18]

- rejected ActewAGL's proposed opex forecast, which was based on its revealed levels of opex, and instead relied on a preferred benchmarking model to estimate ActewAGL's base year opex;

- did not apply the negative EBSS carry forward amounts that would have accrued to ActewAGL from the 2009-14 regulatory control period; and

- proposes to abandon the EBSS in the 2015-19 regulatory control period.

This amounts to substantial change in approach with profound implications for DNSPs' efficiency incentives, which I discuss in detail in section 4 of this report.

2.5   Instructions

Against this backdrop, ActewAGL has asked me to address:

- the effect of making adjustments to base year opex on the basis that a DNSP's expenditure is inefficient relative to its peers on:
    - > the DNSP's resultant incentives under the EBSS to realise efficiency gains; and
    - > the sharing of efficiency gains between DNSPs and network users.

    I address this question in section 4.2 of this report.

- the incentives provided to ActewAGL to identify and implement operating expenditure efficiencies during the 2009/10-2013/14 regulatory control period, and the resultant implications for it to reveal its efficient level of operating expenditure. That is, whether the application of the Old EBSS to ActewAGL in that period created appropriate and effective efficiency incentives;

    I address this question in sections 3.1 and 3.2 of this report.

- if the Old EBSS created appropriate and effective incentives in the previous period for efficient opex decisions by DNSPs, including ActewAGL, the circumstances in which it would not respond appropriately to those incentives;

    I address this question in section 3.3 of this report.

- the effect of a decision by the AER, in making its distribution determination for ActewAGL for the 2015/16-2018/19 subsequent regulatory control period, not to apply the carryover amounts for the 2014/15-2018/19 period arising from the application of the Old EBSS to ActewAGL in the 2009/10-2013/14 regulatory control period, on the sharing between ActewAGL and distribution network users of the amount by which ActewAGL's opex for that period exceeded the forecast opex determined by the AER for that period;

    I address this question in section 4.1 of this report.

- whether and the extent to which a decision by the AER, in making its distribution determination for ActewAGL for the 2015/16-2018/19 subsequent regulatory control period, to determine opex forecasts for the 2014/15-2018/19 period otherwise than by reference to a revealed cost approach and also to apply the carryover amounts for the 2014/15-2018/19 period arising from the application of the Old EBSS to ActewAGL in the 2009/10-2013/14 regulatory control period, would be consistent with the regime for the economic regulation of distribution services established by Chapter 6 of the NER, the objective of the EBSS set out in clause 6.5.8(a) of the NER and the matters set out in clause 6.5.8(c) of the NER;

    I address this question in section 4.3 of this report.

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[17] AER, *ActewAGL distribution determination 2015-16 to 2018-19 Draft decision*, November 2014.
[18]

- whether and the extent to which a decision by the AER, in making its distribution determination for ActewAGL for the 2015/16-2018/19 subsequent regulatory control period, to determine opex forecasts for the 2014/15-2018/19 period otherwise than by reference to a revealed cost approach and not to apply any EBSS to ActewAGL in that period, would be consistent with the regime for the economic regulation of distribution services established by Chapter 6 of the NER, the object of the EBSS set out in clause 6.5.8(a) of the NER and the matters set out in clause 6.5.8(c) of the NER; and

  I address this question in section 4.4 of this report.

- in addressing the foregoing, the consultant is asked to address (amongst other things) the effects of a decision by the AER, in making its distribution determination for ActewAGL for the 2015/16-2018/19 subsequent regulatory control period, to determine opex forecasts for the 2014/15-2018/19 period otherwise than by reference to a revealed cost approach, and not to apply any EBSS to ActewAGL in that period on:

  > ActewAGL's incentives to reduce opex in the 2014/15-2018/19 period; and

  > the sharing between ActewAGL and distribution network users of the amount by which ActewAGL's opex for the 2014/15-2018/19 period is more or less than the forecast opex determined by the AER for that period.

  I address these matters in sections 4.2 and 4.3 of this report.

3. Incentives to Reveal Efficient Costs

In this section I set out my assessment of the incentives provided to ActewAGL to identify and implement opex efficiencies during the 2009-14 control period. Consistent with my instructions, I have had regard to three considerations, ie:

- the incentives provided to ActewAGL to identify and implement operating expenditure efficiencies during the 2009-14 regulatory control period;

- the resultant implications for ActewAGL to reveal its efficient level of opex and, in particular, whether the incentives were sufficient to achieve this outcome; and

- whether there are circumstances in which a DNSP would not respond appropriately to those incentives.

3.1   Incentives for opex efficiency during the 2009-14 regulatory period

The incentive arrangements that operated for ActewAGL for the 2009-2014 period are described in two documents issued by the AER, ie:

- AER, *Electricity Distribution Network Service Providers Efficiency Benefit Sharing Scheme*, June 2008.

- AER, *Electricity Distribution Network Service Providers Efficiency Benefit Sharing Scheme, Final Decision*, June 2008.

3.1.1   The OPEX and carryover allowances

The efficiency incentive arrangements in relation to opex arise from three essential features of the regulatory framework for DNSPs, namely that:

- there is to be no claw back for differences between forecast and outturn opex;

- the opex allowance is to be reset by reference to the revealed opex costs of a DNSP in a "base year" (normally, the penultimate year of the current regulatory period); and

- the 2008 EBSS mechanism.

The analysis that I set out below confirms the AER's conclusion that these arrangements give rise to opex efficiency incentives for a DNSP, such as ActewAGL, that:

- are symmetric, so that the DNSP is both rewarded for any opex efficiency gains and penalised for any efficiency losses incurred in a given year;

- are *invariant as to the timing* at which those efficiency or gains or losses occurred in the regulatory period; and

- that any efficiency gains or losses are shared in the ratio of approximately 30/70 between the DNSP and its users.

Table 1 below illustrates these incentive arrangements by reference to five scenarios, ie:[19]

- scenario A – the DNSP achieves a reduction in recurring opex of 10 units per annum in year 2;

- scenario B – the DNSP achieves a reduction in recurring opex of 10 units per annum in year 4;

- scenario C – the DNSP has an increase in recurring opex of 10 units per annum in year 2;

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[19] Our indicative modelling is set out in Appendix A.1, and assumes a discount rate of 6.0 per cent. Further, for simplicity our modelling assumes no inflation or growth in opex.

- scenario D – the DNSP achieves a one-off reduction in opex of 10 units per annum in year 3; and

- scenario E – the DNSP reports a one-off increase in opex of 10 units per annum in year 1.

Table 1 – Calculation of carryover of a reduction in opex[20]

Scenario A: 10 reduction in opex in year 2

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	0.0	9.4	8.9	8.4	7.9	7.5	7.0	0.0	0.0	0.0	0.0	49.2 (30%)
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.7	6.3	5.9	98.6	117.5 (70%)
Total benefit	0.0	9.4	8.9	8.4	7.9	7.5	7.0	6.7	6.3	5.9	98.6	0.0

Scenario B: 10 reduction in opex in year 4

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	0.0	0.0	0.0	8.4	7.9	7.5	7.0	6.7	6.3	0.0	0.0	43.8 (30%)
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	98.6	104.6 (70%)
Total benefit	0.0	0.0	0.0	8.4	7.9	7.5	7.0	6.7	6.3	5.9	98.6	148.3

Scenario C: 10 increase in opex in year 2

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	0.0	-9.4	-8.9	-8.4	-7.9	-7.5	-7.0	0.0	0.0	0.0	0.0	-49.2 (30%)
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-6.7	-6.3	-5.9	-98.6	-117.5 (70%)
Total benefit	0.0	-9.4	-8.9	-8.4	-7.9	-7.5	-7.0	-6.7	-6.3	-5.9	-98.6	-166.7

Scenario D: One off reduction in opex in year 3 of 10

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	0.0	0.0	8.9	0.0	0.0	0.0	0.0	0.0	-6.3	0.0	0.0	2.6
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.3	0.0	0.0	6.3
Total benefit	0.0	0.0	8.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.9

Scenario E: One off increase in opex in year 1 of 10

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	-10.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	0.0	-3.0 (30%)
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	-7.0	0.0	0.0	0.0	0.0	-7.0 (70%)
Total benefit	-10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0.	0.0	0.0	0.0	-10.0

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[20] Detailed modelling of these results are set out at A3.1.

3.2 Implications for revealed opex

I have been asked by ActewAGL whether the incentives provided under the arrangements applying to the 2009-2014 regulatory period were sufficient for it to reveal its efficient level of opex.

In my opinion, two critical properties of the EBSS bear on this question. First, the EBSS rewards and penalises a DNSP on a symmetrical basis – the carryover mechanism operates so that the effect of permanent efficiency gains as well as losses is sustained for five years. Implicit in this arrangement is that, by providing DNSPs with a share of the benefits of permanent efficiency gains – the result of which is a near term cost to customers – the ultimate reduction in the cost of providing the service will be more significant than would otherwise be the case. By virtue of that outcome, the long term interests of consumers will be enhanced.

Second, the EBSS provides a consistent incentive to businesses to implement efficiency gains. In the absence of any such arrangement, any reliance on outturn costs as a guide to the determination of future regulatory allowances is open to the risk of strategic decision-making by DNSPs. In particular, a business may act to inflate (or defer potential reductions in) its opex in the year adopted as the reference point for establishing forecasts for the next regulatory period, thereby encouraging the adoption of a higher allowance for the ensuing five year regulatory period.

The carryover mechanism and the associated approach to determining future regulatory allowances that underpin the EBSS smooth out the effect of any reduction (or increase) in observed opex that would permeate the establishment of the allowance for the next period. The arrangements are structured so that the strength of the incentive is invariant as to the timing at which an achieved reduction (or increase) in outturn opex occurs. NSPs therefore have no incentive to shift opex from one period to another, and so have a constant incentive to pursue efficiency gains over the entire determination period.

The operation of these arrangements over the 2009-14 period means that ActewAGL has a strong incentive both to act efficiently and to reveal its efficient level of opex. Put another way, it has no incentive to attempt to inflate its opex allowance in the following regulatory period by either:

- artificially increasing opex in the base year ie, year 4; or

- bringing forward opex from year 5 into year 4.

At Table 2 below I set out the rewards/penalties that the 2008 EBSS would deliver to a DNSP, under the following scenarios:

- Scenario A – the DNSP increases its revealed costs in year 4 by 20 units but then immediately reduces it opex by 20 in year 4;

- Scenario B1 – the DNSP achieves new cost savings of 5 units in each of the first three years;

- Scenario B2 – the DNSP achieves new cost savings of 5 units in each of the first three years but then reverses all gains in year 4;

- Scenario B3 – the DNSP achieves new cost savings of 5 units in each of the first three years, but reverses all gains in year 4 and then 'rediscovers' efficiency gains in year 5; and

- Scenario C – the DNSP brings forward 20 units in opex costs from year 5 to year 4.

Table 2 – Artificial increase in opex in year 4[21]

Scenario A: One-off increase in opex in year 4 of 20

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	0.0	0.0	0.0	-16.8	0.0	0.0	0.0	0.0	0.0	11.8	0.0	-4.0 (30%)
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-11.8	0.0	-11.8 (70%)
Total benefit	0.0	0.0	0.0	-16.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-16.8

Scenario B1: Opex efficiency gains in early years

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	5.0	9.4	13.3	12.6	11.9	11.2	7.0	3.3	0.0	0.0	0.0	73.8 (30%)
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	3.5	6.7	9.4	8.9	148.0	148.0 (70%)
Total benefit	5.0	9.4	13.3	8.4	7.9	7.5	10.6	10.0	9.4	8.9	140.0	250.3

Scenario B2: Opex efficiency gains in early years reversed in year 4

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	5.0	9.4	13.3	0.0	0.0	0.0	-3.5	-6.7	-9.4	0.0	0.0	8.2 (30%)
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	3.5	6.7	9.4	0.0	0.0	19.6 (70%)
Total benefit	5.0	9.4	13.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.8

Scenario B3: Early efficiency gains reversed in year 4 & rediscovered in year 5

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	5.0	9.4	13.3	0.0	11.9	11.2	7.0	3.3	0.0	8.9	0.0	70.1 (30%)
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	3.5	6.7	9.4	0.0	148.0	167.6 (70%)
Total benefit	5.0	9.4	13.3	8.4	7.9	7.5	10.6	10.0	9.4	8.9	98.6	237.7

Scenario C: Bring forward year 5 opex to year 4

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	0.0	0.0	0.0	-16.8	15.8	0.0	0.0	0.0	0.0	11.8	-11.2	-0.3 (30%)
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-11.8	11.2	-0.7 (70%)
Total benefit	0.0	0.0	0.0	-8.4	15.8	0.0	0.0	0.0	0.0	0.0	0.0	-1.0

Table 2 highlights that DNSPs face a positive disincentive or penalty if they try to inflate their future opex allowance by inflating their base year (ie, year 4) opex, namely:

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[21] Detailed modelling of these results are set out at A3.2.

- scenario A clearly demonstrates that a DNSP faces a significant penalty if it was to spike its opex in the base year in order to achieve a higher future opex allowance;

- scenario B shows that, if the DNSP is able to achieve efficiency gains in the early years of a regulatory period, then:

  > the DNSP has no incentive to reverse those gains in year 4, since its share of the gains falls from 73.8 in B1 to 8.2 in B2; and

  > the DNSP has no incentive to reverse those gains in year 4 and 'rediscover' those gains in year 5, since its share of the gains falls from 73.8 in B1 to 70.1 in B3; and

- scenario C shows that if it were possible for a DNSP to bring forward opex from year 5 to year 4, it would be worse off as a result.

These examples demonstrate that the incentives created by the 2008 EBSS reward the DNSP for implementing opex reductions, for avoiding unnecessary increases in opex, and for not bringing forward opex. I therefore conclude the incentives provided over the 2009-14 regulatory period – the incentives envisaged by the 2008 EBSS – would reward a DNSP for any efficient opex reductions and penalise it for any opex inefficiencies.

3.3   Circumstances where a DNSP would not respond to incentives

I demonstrate above that the 2008 EBSS will reward a DNSP for all incremental improvements in opex while penalising it for any incremental increases in opex. By ensuring that the opex penalties and rewards are symmetric, continuous and constant, the DNSP is always incentivised to minimise its outturn opex.

I have been asked by ActewAGL to consider whether there are likely to be any circumstances that a DNSP would not respond to these incentives. In other words, might there be any reasons why a DNSP would inflate its outturn opex above the level it could otherwise achieve. In this section I identify a number of plausible reasons as to why a DNSP may choose to inflate its outturn operating expenditure, ie:

- because of events that were not expected at the time of the regulatory determination;

- to achieve future opex efficiencies; or

- to improve service performance.

It follows from each of these potential scenarios that the fact a DNSP's outturn opex is greater than its allowance is not itself sufficient to conclude that it is not responding to the opex incentives. Rather, there are a number of plausible reasons as to why a DNSP may choose to spend more on opex than that allowed for by the regulator at the start of the regulatory period.

3.3.1   Unforeseen opex events

The AER defines efficiency gains and losses as any incremental change in a DNSP's outturn opex against its opex allowance.[22] This is an all-encompassing definition that sets aside many real world complexities. An opex allowance set by a regulator amounts to a forecast of a DNSP's opex at the time of the regulatory decision, and there are a number of plausible reasons why a DNSP's outturn opex during a regulatory period may differ from that expected at the beginning of the regulatory period.

First, the opex allowance is generally predicated on a forecasts of input cost escalators, for which the outturn experience will inevitably be different. For example, ActewAGL Distribution's 2009-14 opex allowance is predicated on AER estimates of growth in energy gas and water sector labour costs and ACT general labour costs, which I summarise at Table 3, overleaf.

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[22] AER, *Electricity Network Service Providers | Proposed Efficiency Benefit Sharing Scheme*, August 2013, page 5.

Table 3 – AER conclusion on ActewAGL's real EGW and general labour escalators (per cent) [Table 9.7, Final Decision]

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14
EWG labour	2.42	2.50	3.60	2.90	2.50	1.50
General labour	-2.50	0.50	1.30	1.00	0.90	0.20

However, outturn real general labour costs in the ACT were substantially higher than those forecast by the AER at ActewAGL's 2009 determination. I summarise these at Table 4, below.

Table 4 – ACT real labour costs and the AER estimate of real general labour escalators (per cent)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14
AER forecasts of General labour	-2.50	0.50	1.30	1.00	0.90	0.20
Outturn labour costs*	2.39	0.37	0.02	2.03	1.37	-0.65

Source: ABS, Consumer Price index and Total hourly rates of pay excluding bonuses; Australian Capital Territory; private and Public; All industries.

Circumstances where labour costs are higher than forecast may explain why a DNSP's outturn opex is greater than that forecast by the regulator.

Second, the opex tasks required to be undertaken by the DNSP may turn out to be different from that forecast. For example, unforeseen growth in customer connections or the size of the network would be likely to result in higher than forecast opex costs for the DNSP.

A DNSP may also incur unforeseen environmental, regulatory and tax costs during the regulatory period. For example, I note that in 2012/13 ActewAGL Distribution incurred:[23]

- an additional $1.9 million in vegetation management costs due to two years of above average rainfall; and

- an Comcare exit fee of $1.8 million.

3.3.2   Invest in future opex efficiencies

The incentives created by the 2008 EBSS are symmetric in that a DNSP bears approximately 30 per cent of the cost of any incremental increases in opex while also receiving approximately 30 per cent of the value of any incremental decreases in opex. This symmetry means that a DNSP has an incentive to incur higher opex today if it results in a sufficient fall in future opex.

I illustrate this point in Table 5, which analyses the extent to which a DNSP will be willing to increase opex for one year to achieve a reduction in future recurring opex. Table 5 considers the following three scenarios:

- scenario A: to achieve a 10 unit reduction in future recurring opex requires the DNSP to incur additional opex of 166.7 in year 1;

- scenario B: to achieve a 10 unit reduction in future recurring opex requires the DNSP to incur additional opex of 150 in year 1; and

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[23] ActewAGL, *Subsequent regulatory proposal*, July 2014, pages 218 and 224.

- scenario C: to achieve a 10 unit reduction in future recurring opex requires the DNSP to incur additional opex of 200 in year 1.

Table 5 – Increase in opex to achieve future opex efficiencies[24]

Scenario A: Increase in year 1 opex of 166.7

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	-166.7	9.4	8.9	8.4	7.9	7.5	124.5	0.0	0.0	11.8	0.0	0.0
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	-117.5	6.7	6.3	5.9	98.6	0.0
Total benefit	-166.7	9.4	8.9	8.4	7.9	7.5	7.0	6.7	6.3	5.9	98.6	0.0

Scenario B: Increase in year 1 opex of 150

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	-150.0	9.4	8.9	8.4	7.9	7.5	112.8	0.0	0.0	0.0	0.0	4.9 (30%)
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	-105.7	6.7	6.3	5.9	98.6	11.7 (70%)
Total benefit	-150.0	9.4	8.9	8.4	7.9	7.5	7.0	6.7	6.3	5.9	98.6	16.7

Scenario C: Increase in year 1 opex of 200

	1	2	3	4	5	6	7	8	9	10	10+	Total
Discounted benefit to NSP	-200.0	9.4	8.9	8.4	7.9	7.5	148.0	0.0	0.0	0.0	0.0	-9.8 (30%)
Discounted benefit to customers	0.0	0.0	0.0	0.0	0.0	0.0	-141.0	6.7	6.3	5.9	98.6	-23.5 (70%)
Total benefit	-200.0	9.4	8.9	8.4	7.9	7.5	7.0	6.7	6.3	5.9	98.6	-33.3

These scenarios illustrate the circumstances in which DNSPs have an incentive to incur additional opex today in order to achieve future opex savings, including that:

- the DNSP will only have an incentive to incur additional opex today if the future benefits in terms of lower ongoing opex outweigh the cost of the immediate increase in opex; and

- that the DNSP will be prepared to incur substantial increase in short term opex to achieve a permanent reduction in opex, ie, in scenario A, the DNSP would be prepared to expend and up to an additional 166.7 to achieve a reduction in recurring opex of 10.

I note that the incentive to incur greater opex in the short term in order achieve subsequent reductions in recurring opex would be undermined if the fact of such higher opex raises the risk that the DNSP's future opex allowance is determined by way of AER benchmarking. This is because such an outcome would cause the DNSP to bear all the costs of the higher initial opex, but receive none of the benefits from the resulting reduction in recurring opex. It follows that DNSPs will be less willing to incur short term costs for long term reductions in opex, even when it is efficient to do so.

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[24] Detailed modelling of these results are set out at A3.3.

In other words, the threat that a DNSP's opex allowance will be set by reference to benchmarking acts to undermine the incentives that regulated business has to pursue future opex efficiency.

3.3.3   Improve service quality

A further potential reason that a DNSP may increase its incremental opex arises when that extra expenditure results in an improvement in service quality. DNSPs are subject to the service target performance incentive scheme (STPIS), which the AER describes as follows:[25]

> While the regulatory regime as a whole encourages a business to improve its operating and capital efficiency, the STPIS is designed to ensure that this increase in efficiency is not at the expense of a deterioration in service performance for customers. Further, the STPIS is designed to encourage a business to improve its service performance where customers are willing to pay for these improvements.

It follows that a DNSP may be prepared bear the penalties imposed by the 2008 EBSS for increasing opex when that additional expenditure was directed towards improving its service performance.

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[25] AER, *Electricity Distribution Network Service Providers | Service target performance incentive scheme: Final decision*, November 2009, page 3.

4. Benchmark-based Adjustments to Opex

In this section I set out my assessment of the implications of moving away from the revealed cost approach to setting a firm's opex allowance and the abandonment of the EBSS. In particular, my assessment considers:

- the changes proposed in the draft decision that alter the share borne by ActewAGL of unforeseen opex overruns that occurred in the 2009/10-2013/14 period (see section 4.1);

- the share of efficiency gains that are retained by the DNSP as opex costs fall from revealed levels to a new 'efficiency frontier' and illustrate the new incentive for opex efficiency (see section 4.2);

- the extent to which the incentives created by the proposed opex arrangements are consistent with the principles set out in clause 6.5.8(a) and clause 6.5.8(c) of the NER (see section 4.3); and

- the broader implications for incentives of the proposed opex arrangements to apply to ActewAGL (see section 4.4).

4.1   Effect on the share of the 2009/10-2013/14 efficiency gains/losses

I described in section 2 the two critical incentive properties of the EBSS; namely: the symmetry of rewards and penalties; and, the continuous and constant incentive that exists over the regulatory period. The effectiveness of the EBSS turns on these two properties, and any modification to the scheme that disturbs either of these incentives has the potential to undermine the objectives that guided its design.

The current EBSS operates over two periods, through its influence on three elements of the revenue allowance process, ie:

- differences between forecast and outturn levels of opex within a regulatory period are not clawed back and retained by the DNSP;

- deviations from forecast levels of opex in later years of any regulatory period give rise to corresponding payments (or penalties) in the subsequent regulatory period (with the degree of carryover driven by the timing at which such deviation take place); while

- the adoption of outturn opex for the fourth year of any regulatory period as the basis for the opex allowance to apply from the commencement of the subsequent regulatory period ensures that any savings made in the fifth year are also carried over (by means of an 'inflated' opex allowance) into the following period.

The interaction of these three elements had the effect of sharing any efficiency gains or losses that occurred in the 2019/10-2013/14 regulatory control period on an approximate 30:70 basis between ActewAGL and its customers, respectively. However, the AER's draft decision essentially abandons this framework by:

- resetting ActewAGL's opex by reference to comparative efficiency, rather than by revealed costs; and

- the immediate removal of the EBSS mechanism.

In the following sections, I demonstrate that the application of these proposed changes profoundly alters the incentives of network businesses, relative to the original design objective.

To assist in demonstrative the effect of this undermining of the architecture of the EBSS, I have calculated the opex gains and losses for the 2009-14 regulatory period that accrue to ActewAGL under the incentive framework implied by the draft decision.

Table 6 – ActewAGL 2009-14 EBSS and future opex allowance ($m, 2013/14)

Year ending 30 June	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
EBSS target	55.7	56.3	57.4	59.4	59.1	42.5	43.2	44.1	44.8	45.6
Actual opex	57.2	65.5	70.1	70.2	69.8*	42.5	43.2	44.1	44.8	45.6
Carryover in year:	-1.5	-7.7	-3.5	1.9						
1		-1.5	-1.5	-1.5	-1.5	-1.5				
2			-7.7	-7.7	-7.7	-7.7	-7.7			
3				-3.5	-3.5	-3.5	-3.5	-3.5		
4					1.9	1.9	1.9	1.9	1.9	
5						0	0	0	0	0
EBSS Carry forward	0	0	0	0	0	-10.7	-9.2	-1.5	1.9	0
Total opex allowance	55.7	56.3	57.4	59.4	59.1	42.5	43.2	44.1	44.8	45.6
ActewAGL penalty/reward	-1.5	-9.2	-12.7	-10.7	-10.7	0	0	0	0	0

* Estimated opex from ActewAGL RIN.

Table 6 highlights that, over the 2009/10-2013/14 regulatory control period, ActewAGL's actual opex is estimated to be $44.9 million (2013/14 dollars) greater than the opex allowance provided by the AER's 2009 decision. Under the 2009 EBSS framework, this cost overrun would give rise to a negative EBSS carry forward amount of $19.6 million (2013/14 dollars), while ActewAGL's opex allowance would be re-based to reflect the revealed opex in 2012-13.

However, the distortion to the incentive framework created in the draft decision cause ActewAGL to bear the full cost of the opex over runs incurred during the 2009-14 period. Through its retrospective change the sharing arrangements contemplated at the start of the 2009/10-2013/14 regulatory control period, the draft decision alters the share of opex overruns between ActewAGL and its customers from a 30:70 basis,[26] to one where ActewAGL bears 100 per cent of its $44.9 million (2013/14 dollars) opex cost overrun.

To maintain the intended sharing ratio of 30:70 would require the AER to add $36.7 million (2013/14 dollars) to ActewAGL's 2014-15 revenues.[27]

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[26] AER, *Draft Decision ActewAGL distribution determination 2015-1 to 2018-19 | Attachment 9: Efficiency Benefit Sharing Scheme,* November 2014, page 9-9.

[27] Based on a 6.17 per cent real Vanilla WACC.

4.2 Share of future efficiency gains

Consistent with my instructions, I have also considered incentive effects of the AER's draft decision:

- not to use revealed opex costs to set the opex allowance when it is not satisfied that base year opex reasonably reflects the opex criteria; and

- not to apply the EBSS when the opex allowances are not set by reference to a DNSP's revealed base year opex costs.

The pivotal question that arises is the long term outcomes for DNSPs that meet or outperform the benchmark level of opex. I have therefore examined the long term outcomes under five different scenarios, namely:

- scenario A – the DNSP is unable to achieve any of the opex reduction suggested by the benchmarking;

- scenario B – the DNSP is only able to achieve 50 per cent of the opex reduction suggested by the benchmarking;

- scenario C – the DNSP achieves the benchmark level of opex expenditure;

- scenario D – the DNSP outperforms the benchmark level of opex, achieving 150 per cent of the opex reduction suggested by the benchmarking; and

- scenario D – the DNSP outperforms the benchmark level of opex, achieving 200 per cent of the opex reduction suggested by the benchmarking.

I set out the results of my analysis in Table 7, overleaf, and provide a graphical summary in Figure 1, below.

Figure 1 – Sharing of long term benefits between DNSP and consumers (Scenarios A to E)
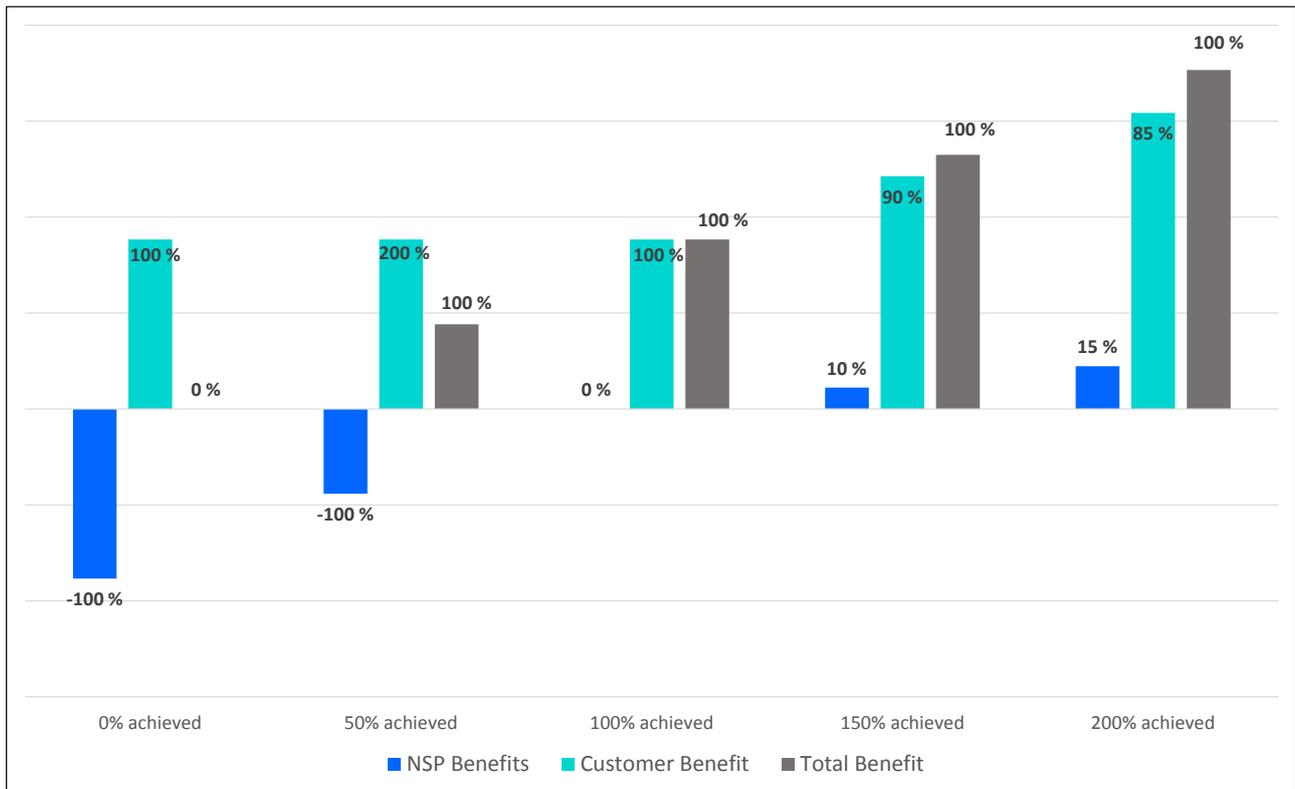
Table 7 – Sharing of long term benefits between NSP and consumers (Scenarios A to E)[28]

Scenario A: 0% achievement of benchmark level of expenditure												
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**10+**	**Total**
Discounted benefit to NSP	-10.0	-9.4	-8.9	-8.4	-7.9	-7.5	-7.0	-6.7	-6.3	-5.9	-98.6	-176.7
Discounted benefit to customers	10.0	9.4	8.9	8.4	7.9	7.5	7.0	6.7	6.3	5.9	98.6	176.7
Total benefit	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Scenario B: 50% achievement of benchmark level of expenditure												
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**10+**	**Total**
Discounted benefit to NSP	-5.0	-4.7	-4.4	-4.2	-4.0	-3.7	-3.5	-3.3	-3.1	-3.0	-49.3	-88.3
Discounted benefit to customers	10.0	9.4	8.9	8.4	7.9	7.5	7.0	6.7	6.3	5.9	98.6	176.6
Total benefit	5.0	4.7	4.4	4.2	4.0	3.7	3.5	3.3	3.1	3.0	49.3	88.3

Scenario C: 100% achievement of benchmark level of expenditure												
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**10+**	**Total**
Discounted benefit to NSP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Discounted benefit to customers	10.0	9.4	8.9	8.4	7.9	7.5	7.0	6.7	6.3	5.9	98.6	176.7
Total benefit	10.0	9.4	8.9	8.4	7.9	7.5	7.0	6.7	6.3	5.9	98.6	176.7

Scenario D: 150% achievement of benchmark level of expenditure												
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**10+**	**Total**
Discounted benefit to NSP	5.0	4.7	4.4	4.2	4.0	0.0	0.0	0.0	0.0	0.0	0.0	22.3
Discounted benefit to customers	10.0	9.4	8.9	8.4	7.9	11.2	10.6	10.0	9.4	8.9	148.0	242.9
Total benefit	15.0	14.2	13.3	12.6	11.9	11.2	10.6	10.0	9.4	8.9	148.0	265.0

Scenario E: 200% achievement of benchmark level of expenditure												
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**10+**	**Total**
Discounted benefit to NSP	10.0	9.4	8.9	8.4	7.9	0.0	0.0	0.0	0.0	0.0	0.0	44.7
Discounted benefit to customers	10.0	9.4	8.9	8.4	7.9	14.9	14.1	13.3	12.5	11.8	197.3	308.7
Total benefit	20.0	18.9	17.8	16.8	15.8	14.9	14.1	13.3	12.5	11.8	197.3	353.3

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[28] Detailed modelling of these results are set out at A3.4.

By way of explanation, in Table 7:

- the grey columns represent the total reduction in expenditure versus its initial level of opex achieved by the DNSP – for each scenario I have set this value equal to 100 per cent, establishing a basis for comparison;[29]

- the blue and green columns represent the sharing of the total efficiency gain received by the DNSP and consumers, respectively; and

- I have included labels that denote the DNSP and consumer share of the total efficiency gain as a percentage of the 'total efficiency gain', eg, in the '150 % achieved' scenario, the DNSP and customer shares are 10 and 90 per cent of the total efficiency gain, respectively.

Further, I note that:

- in scenarios A, B and C, the DNSP bears the entire difference between its expenditure and the benchmark level of opex - in these three scenarios, all efficiency gains achieved are received only by customers;

- in scenarios D and E, the DNSP outperforms its benchmark, and so triggers a reversion to a revealed cost level of opex - in both these scenarios, the absence of the EBSS means that, to the extent that the DNSP outperforms the benchmark, then distributor will retain less than 30 per cent of the benefits of the outperformance; and

- in scenarios D and E, the absence of EBSS also means that the share of the gains retained by the DNSP will depend on the timing of when the outperformance occurs with:

  > for outperformance occurring in year 1, the DNSP will retain the benefits of the outperformance for 5 years, which results in a sharing ratio of 25:75 between ActewAGL and its customers, respectively;[30]

  > for outperformance occurring in year 2, the DNSP will retain the benefits of the outperformance for 4 years, which results in a sharing ratio of 20:80 between ActewAGL and its customers, respectively;[31]

  > for outperformance occurring in year 3, the DNSP will retain the benefits of the outperformance for 3 years, which results in a sharing ratio of 16:84 between ActewAGL and its customers, respectively;[32]

  > for outperformance occurring in year 4, the DNSP will retain the benefits of the outperformance for 2 years, which results in a sharing ratio of 11:89 between ActewAGL and its customers, respectively;[33] and

  > for outperformance occurring in year 5, the DNSP will retain the benefits of the outperformance for 1 year, which results in a sharing ratio of 6:94 between ActewAGL and its customers, respectively.[34]

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[29] In the first scenario, there are no efficiency gains, and so I have assigned the total efficiency gains a value of 0 per cent. This scenario essentially represents a direct transfer from DNSPs to customers.

[30] A business that permanently reduces its opex below benchmark levels in the first year of a regulatory period, retains the benefit of its opex allowance being greater than its actual costs for 5 years. I have assumed that at the end of the regulatory period a business' opex allowance would be reset to reflect revealed levels and so the network would retain the benefits of underspending its allowance for 5 years which results in the network retaining 25 per cent of the total benefit, in present value terms, using a 7 per cent real discount factor.

[31] In this scenario the network reduces its opex below benchmark levels in the second year of a regulatory period and so retains the benefit for 4 years which results in it retaining approximately 20 per cent of the total benefit, in present value terms, using a 7 per cent real discount factor.

[32] In this scenario the network reduces its opex below benchmark levels in the third year of a regulatory period and so retains the benefit for 3 years which results in it retaining approximately 16 per cent of the total benefit, in present value terms, using a 7 per cent real discount factor.

[33] In this scenario the network reduces its opex below benchmark levels in the fourth year of a regulatory period and so retains the benefit for 2 years which results in it retaining approximately 11 per cent of the total benefit, in present value terms, using a 7 per cent real discount factor.

[34] In this scenario the network reduces its opex below benchmark levels in the last year of a regulatory period and so retains the benefit for 1 years which results in it retaining approximately 6 per cent of the total benefit, in present value terms, using a 7 per cent real discount factor.

4.3   Implications for incentives to reduce opex

The analysis I present above shows that the AER's proposed approach to setting the opex allowance and its associated abandonment of the EBSS has profound, negative consequences for the efficiency incentives faced by a DNSP.

I note that the clause 6.5.8(c) of the National Electricity Rule (the "rules") provides detailed guidance as to the incentive regime that is intended to operate for DNSPs with respect to opex, namely:

In developing and implementing an efficiency benefit sharing scheme, the AER must have regard to:

- *the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for Distribution Network Service Providers;*

- *the need to provide Distribution Network Service Providers with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure ;*

- *the desirability of both rewarding Distribution Network Service Providers for efficiency gains and penalising Distribution Network Service Providers for efficiency losses*

- *any incentives that Distribution Network Service Providers may have to capitalise expenditure; and*

- *the possible effects of the scheme on incentives for the implementation of non-network alternatives.*

In my opinion, the incentive framework implied by the AER's draft decision in relation to ActewAGL departs substantially from these specified requirements.

The proposed arrangements reduce the incentive for future opex efficiency

The arrangements proposed in the draft decision completely undermine the incentive that a DNSP has to incur prudent but higher opex today, where that expenditure gives rise to a reduction in future recurring opex. I explained in section 3.3.2 that the old EBSS aligned the regulatory incentives of a DNSP with the objective of long term productive efficiency by allowing the DNSP to retain approximately 30 per cent of any opex efficiency gains or losses.

The consequence of those arrangements was that a DNSP would have an incentive to incur higher short-term costs if that expenditure yielded sufficient future opex savings.[35] However, the alignment between the regulatory incentives of a DNSP and the long term productive efficiency objective is destroyed by the proposed opex arrangements.

Rather, under the proposed framework, a DNSP that incurs restructuring costs that allow it to reduce future recurring levels of opex will be less inclined to proceed with these prudent actions under the new framework because:

- the higher levels of short-term opex increase the possibility that the DNSP's base year costs will be deemed to be inefficient, causing the suspension of the EBSS and, further, its revealed costs no longer to be used as the basis for setting its opex allowance; so that

- the DNSP would then bear 100 per cent of the additional costs associated with the restructuring; while

- none of the benefits of the restructure (in terms of lower future recurring opex) would be retained by the DNSP since its opex allowances would set by reference to benchmarked efficient levels.

It follows that, although the application of benchmarking has resulted in a lower short term opex allowance for ActewAGL, this comes at the cost of virtually eliminating its incentive to incur restructuring costs that

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[35] That is, the DNSP would have positive financial reward if the net present value of the future opex savings outweighs the present value of the higher short term opex costs.

would give rise to lower future opex. I note that these consequences were not considered by the AER in its draft decision.

The proposed arrangements do not provide a continuous incentive

I set out in section 4.2 that under the revised incentive arrangements implied by the draft decision, the sharing ratio for efficiency gains is no longer invariant through time. In other words, the share of the benefits from outperforming the opex allowance that are retained by a DNSP falls through the regulatory period, ie, from 25 per cent (for outperformance in the first year of the regulatory control period) to 6 per cent per cent (for outperformance in the final year of the regulatory period).

The consequence of this declining incentive is to encourage a DNSP to delay any efficient reductions in opex below the benchmark levels until either:

- the first year of the regulatory control period, so as to retain 25 per cent of the benefits; or
- to a period when the EBSS would apply, so that the DNSP is able to retain 30 per cent of the efficiency gains.

The proposed arrangements do not reward a DNSP for efficiency gains

The incentives provided by the scheme also cease to be symmetrical. Rather, the AER's proposed approach involves a highly asymmetric sharing of efficiency gains, losses, and risks.

In assessing the symmetry of incentives, it is helpful first to define the concept of an efficiency gain or loss. Efficiency of a business is a recognised economic term that, in essence represents a ratio of a firm's outputs to its inputs.[36] Consequently, an efficiency gain can be said to occur where either:

- the quantum of a firm's outputs rise while the quantum of inputs used remain constant; or
- the quantum of inputs used by a firm falls while the level of outputs remain constant; or
- the quantum of outputs used by a firm increases at a greater rate that the quantum of inputs.

In other words, a DNSP that is able to reduce its opex costs below its current level without a concurrent reduction in output must have achieved an "efficiency gain".

However, the effect of the incentives implied by the AER's draft decision is to penalise the DNSP up to the point that it is able to achieve the benchmark level of opex. In other words, it receives no reward for reducing its opex to the benchmark levels.

I illustrate in Figure 1 that a DNSP that achieves 50 per cent of the opex efficiency reductions suggested by benchmarking would receive a penalty equal to the value of the efficiency improvements, ie, equal to the failure to achieve the other 50 per cent opex reductions suggested by the benchmarking. To put this in context, if ActewAGL were able to reduce its annual opex from $69.8 million (2013/14 dollars) by $13.65 million per annum (a 20 per cent reduction in annual opex), it would be face a penalty because its opex costs are still $13.65 million higher than the level set by the AER's proposed opex allowance.

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[36] See AER, *Better Regulation | Explanatory Statement | Expenditure Forecast Assessment Guideline*, November 2013, page 78 that states:

> *Economic benchmarking applies economic theory to measure the efficiency of a NSP's use of inputs to produce outputs, having regard to environmental factors.*

The proposed arrangements substantially change the incentive to capitalise expenditure

When developing the new Capital Expenditure Sharing Scheme (CESS) one of the principal reasons for the AER setting the incentive rate at 30 per cent was to:[37]

> … achieve a balance between the incentives for capex and opex. The incentives for opex are approximately 30 per cent. A reward and penalty which is relatively balanced between opex and capex will help to ensure a NSP makes efficient decisions when choosing whether to incur opex or capex.

An important function of the CESS was to align the incentives between opex and capex, on the presumption that DNSPs remain are subject to the old EBSS and revealed cost framework. However, the opex incentive arrangements implied by the draft decision now result in a fundamental disconnect between the incentives for opex and those that now apply to capex.

In particular, for so long as a DNSP's actual opex is above the efficient level suggested by the AER's benchmarking analysis, it has a strong incentive to capitalise expenditure. This is because:

- the penalty for increasing capex under the CESS would be 30 cents in every additional dollar of capitalised expenditure; while
- the benefit of decreasing opex to the benchmark results in reduced penalty of $1 for every additional of capitalised expenditure.

In other words, the DNSP receives a net benefit of 70 cents for every dollar that is shifted from opex to capex.

However, in light of the asymmetric and time-inconsistent incentives caused by the proposed framework, if the DNSP's actual opex is below the efficient level suggested by the AER's benchmarking analysis, then a DNSP will have an incentive to shift expenditure from capex to opex because:

- the opex penalty in the absence of the EBSS range from 25 per cent (for year 1 expenditure) to 6 per cent (for year 5 expenditure); while
- the benefit from decreasing capex under the CESS would be 30 cents in every additional dollar of capitalised expenditure.

The proposed arrangements undermine the incentive to procure demand management services

Non-network alternatives to network investments generally involve a DNSP purchasing demand management (DM) services that curtail demand, thereby allowing it to defer or avoid a network investment. Consequently, the procuring DM services involves a DNSP increasing its opex expenditure (ie, to procure DM services) to defer or avoid capex (ie, the network investment).

However, the opex incentive arrangements implied by the AER's draft decision give rise to substantially different incentive rates on opex and capex efficiency gains, undermining the rationale for a DNSP to procure efficient DM services.[38]

For so long as a DNSP's actual opex is above the efficient level suggested by the AER's benchmarking analysis, then the financial penalties associated with procuring DM services (ie, the DNSP bears 100 per cent of the additional DM costs) will outweigh the financial rewards associated with the deferment of the network capex, ie, where the DNSP receives 30 percent of the value of the network deferment. The consequence is that a DNSP will no longer have a financial incentive to procure DM services, unless the

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[37] AER, *Better Regulation | Explanatory Statement | Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, page 42.

[38] Efficient DM services would be those services where the present value of the benefits of deferring the network investment outweigh the present value of the cost of procuring DM services.

present value of the benefits from deferring capex is 333% greater than the present value of the cost of procuring DM services.

Conclusion

To summarise, the AER's proposed approach to setting the opex allowance and its associated abandonment of the EBSS will have profound effects on the efficiency incentives for a DNSP. The proposed changes give rise to incentive arrangements that are wholly inconsistent with the principles set out in clause 6.5.8(c) of the rules. The deficiencies I have identified show that the incentive arrangements sitting within the combination of measures proposed by the AER are deeply flawed. In my opinion, the draft decision gives insufficient attention to the long term incentives its create, and undermines the existing regulatory framework that, with the introduction of the CESS, would otherwise have aligned the incentives on a DNSP to deliver long term efficiency.

In the next section, I consider the wider implications of the proposed changes to the opex arrangements.

4.4   Wider implications of proposed changes to the opex arrangements

The proposed opex arrangements have a number of wider implications for the regulatory framework, including in particular:

- the broader implications of relying on benchmarking to set the opex allowance;
- the retrospective nature of the change; and
- the incentive framework applying to service quality.

I discuss these wider implications in turn below.

4.4.1   Broader implications of benchmarking

I have described that the AER's proposed approach will cause businesses to face considerable costs in the event that they fail to achieve the benchmark level of opex. Implicit within the approach is an assumption that expenditure above the 'efficient level' – as established through the benchmark – is always undesirable.

By contrast, there are at least two circumstances where this is simply not the case, ie:

- where the benchmark is in error; or
- where the benchmark is not achievable.

The benchmark is in error

A critical requirement for the responsible use of a benchmark expenditure allowance is for the benchmark to be a reasonable reflection of the 'efficient level' of expenditure for a DNSP. Significant risks arise in circumstances where the opex allowance *underestimates* the efficient level of expenditure, ie, the benchmark is too low.

Adoption of a benchmark that is too low not only fails to provide the right incentive to a DNSP, but may encourage a DNSP to make decisions that are contrary to the long term interests of consumers. Most notably, a benchmark opex allowance that is 'too low' encourages a DNSP to spend less on opex than is efficient – because it bears more than 100 per cent of any expenditure above the opex allowance.

These interactions inevitably cause significant attention to be given to the degree to which the benchmark can be relied upon, and the risk of disconnect between the benchmark and actual efficient levels of expenditure. The merits of the AER's benchmarking approach are beyond the scope of my report. Nevertheless, I note that the greater the uncertainty associated with the benchmark level of opex, the greater the potential for benchmarking of businesses to have detrimental outcomes for consumers.

The benchmark is not achievable

Even if the benchmark were assumed to be free of uncertainty, it does not follow that the benchmark is achievable. I have already described circumstances where a business might not respond to the incentives provided by the regulatory framework, a corollary of which is a DNSP not being able to achieve its benchmark level of opex.

In the event that a business cannot achieve the benchmark, the end result is ultimately a loss of revenue for the DNSP – revenue that the DNSP requires to maintain its network and ensure reliable supply to its customers. This gives rise to the question of whether adherence to an efficient but unachievable benchmark leads to recovery of the level of revenue that is consistent with the long term interest of consumers. In my opinion, it does not.

4.4.2 Retrospective changes

Investing in electricity distribution infrastructure involves substantial upfront investments whose costs are recovered over multiple regulatory control periods. The regulatory arrangements are critical to determining the basis for cost recovery and the risk of not recovering the cost of an investment. Ex-post adjustments that affect investors' reasonably anticipated returns will increase the level of uncertainty and reduce predictability in the regulatory environment.

The proposed opex arrangements set out in the draft decision retrospectively change the sharing of cost overruns experienced in the 2009/10-2013/14 regulatory control period. The existing opex arrangements set out prior to the start of the 2009/10-2013/14 regulatory control period clearly intended that with the EBSS, the DNSP and consumers would share the benefits or fund the cost of differences between the level of opex forecast and that actually incurred by the DNSP.[39] Further, the benefits or costs of any differences would be shared between the DNSP and its customers on a 30:70, basis.

However, the AER's draft decision of November 2014 now proposes that, for expenditure that occurred between 1 July 2009 and 30 June 2014, ActewAGL must bear 100 per cent of the opex costs in excess of the allowance determined by the AER. This retrospective change in the sharing ratio has material financial consequences given that ActewAGL overspent its EBSS target level of opex by $44.9 million (2013/14

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[39] See AER, *Electricity Distribution Network Service Providers Efficiency Benefit Sharing Scheme | Final Decision*, June 2008, page 23.

dollars) during this period. To maintain the intended sharing ratio of 30:70 would require the AER to add $36.7 million (2013/14 dollars) to ActewAGL's 2014-15 revenues.[40]

A failure to adjust revenue to achieve the sharing ratio operating under the 2008 EBSS increases the level of uncertainty in the regulatory environment and, in so doing, substantially increases the level of regulatory risk. Regulatory risk increases the prospect of investors' expectations as to the return on or of capital for a particular project not being met, and so increases a regulated firm's cost of providing capital, to the detriment of the long term interests of consumers.

In my opinion, retrospective changes to the regulatory framework that result in unanticipated and material financial losses to a DNSP are unnecessary and inconsistent with the long term interests of consumers as required by the NEO.

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[40] This adjustment has been calculated to ensure that the sharing ratio is 30:70 between ActewAGL and its customers in present value terms based on the regulated real Vanilla WACC of 6.17 per cent as determined for the 2009/10-2013/14 regulatory control period.

4.4.3   The proposed opex arrangements undermine the service quality incentive framework

ActewAGL is subject to the national distribution service target performance incentive scheme (STPIS).[41] STPIS provides a financial incentive to ActewAGL to maintain and improve service performance and is calibrated so the distributor retains the value of any incremental improvements (or bears the cost of any incremental deteriorations) in service performance for a period of 5 years. Under the STIPS, the DNSP retains approximately 25 per cent of the value of any improvements in service performance as well as bearing 25 per cent of the value of any reductions in service performance.[42]

It follows that the STIPS closely aligns to the incentives provided through both the current, 2008 EBSS and the CESS. However, this alignment is destroyed by the proposed opex arrangements set out in the draft decision. In particular, for so long as a DNSP's actual opex is above the efficient level suggested by the AER's benchmarking analysis, it has a strong incentive to reduce service performance so as to minimise the opex penalty. This distortion arises because, under the incentives implied by the draft decision, a DNSP would bear 100 per cent of the cost being above the level of the AER's opex allowance. In contrast, under the STIPS, the DNSP would only bear 25 per cent of the value of the change in service performance.

It follows that, under the proposed opex arrangements, a DNSP would:

*   not have an incentive to incur any additional opex costs in order to improve service performance, even if it was efficient to do so;[43] and

*   have an incentive to reduce opex costs, even if it results in an inefficient deterioration in service performance.[44]

It is difficult to reconcile how the distortion between the incentives for service performance and those that operate for opex, which could potentially result in inefficient levels of service performance, could be in the long-term interests of consumers, or consistent with the NEO.

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[41] AER, *Electricity distribution network service providers | service target performance incentive scheme*, 1 November 2009.

[42] A DNSP that is able to perpetually improve service performance and is able to retain the value of that service improvement for five years under the STIPS would retain approximately 25 per cent of a value of the perpetual improvement in service performance based on a real discount rate of 6 per cent.

[43] Efficient improvements in service performance occur when the present value to customers of the improvement in service performance outweighs the present value of the additional opex costs necessary to improve service performance.

[44] An inefficient deterioration in service performance occurs when the present value of the opex savings that cause the fall in service performance is less than the present value to customers of the deterioration in service performance.

5. Conclusion

ActewAGL has asked that I address a number of questions concerning the relationship between the operating expenditure (opex) allowance that is to be determined in the AER's distribution determination, and the Efficiency Benefit Sharing Scheme (EBSS) applying in relation to the immediately prior regulatory period

In section 3 of my report, I examine the opex incentives that applied in relation to ActewAGL for the 2009/10-2013/14 regulatory control period. I find that, consistent with the AER's guidelines, the efficiency incentive arrangements in relation to opex arise from three essential features of the regulatory framework for DNSPs, namely:

- there is to be no claw back for differences between forecast and outturn opex;
- the opex allowance is to be reset by reference to the revealed opex costs of a DNSP in a "base year" (normally, the penultimate year of the current regulatory period); and
- the 2008 EBSS mechanism.

My findings concur with those of the AER that these arrangements create an appropriate and effective incentive structure that encourages a DNSP, such as ActewAGL, to pursue efficient reductions in opex. This conclusion applies by virtue of four particular properties, ie, that:

- incentives are symmetric, so that a DNSP is both rewarded for any opex efficiency gains and penalised for any efficiency losses incurred in a given year;
- incentives are *invariant as to the timing* at which those efficiency or gains or losses occurred in the regulatory period;
- any efficiency gains or losses are shared in the ratio of approximately 30/70 between the DNSP and its users; and
- the incentives accord with those applying to capex and service quality.

The consequences of these properties is that, by providing DNSPs with a share of the benefits of incremental efficiency gains – the result of which is a near term cost to customers – in the long-term cost of providing the service can be expected to be lower than would otherwise be the case. By virtue of that outcome, these arrangements are in the long term interests of consumers and serve to promote the NEO.

These arrangements also remove the risk of strategic decision-making by DNSPs. In other words, a DNSP receives no net financial gain from inflating its opex in the year adopted as the reference point for establishing forecasts for the next regulatory period, thereby encouraging the adoption of a higher allowance for the ensuing five year regulatory period.

It follows that the opex costs incurred by ActewAGL in its base year can be presumed to be efficient, and can and should be relied on as the basis for setting its opex allowance for the 2014/15-2018/19 regulatory control period. Notwithstanding, I have also been asked to consider whether there are any circumstances under the existing opex arrangements that a DNSP would not respond to incentives and increase its incremental opex. I have identified four circumstances in which a DNSP may reasonably choose to incur higher incremental opex. These are that:

- events that were unexpected at the time of the regulatory determination occur, such as the forecasts that were relied on to establish the opex allowance did not eventuate and so a DNSP efficiently incurred opex costs greater than forecast;
- the DNSP efficiently incurred short-term costs (ie, restructuring costs) that allow it to reduce long-term recurring opex costs, for which I also find that a DNSP would be prepared to incur substantial short term opex costs in order to achieve a permanent reduction in opex;

- a misalignment of incentives between opex and capex could provide inappropriate incentives for a DNSP to increase its incremental opex, however:

  > the capex incentive applying hitherto declined through the regulatory control period and would not induce ActewAGL to inflate its base year opex (if anything the incentives in the base year would be to convert opex to capex and so understate base year opex); and

  > the CESS that will operate from the 2014/15-2018/19 regulatory control period aligns capex and opex incentives (were the EBSS and revealed costs to continue to apply); and

- the DNSP incurred additional opex to efficiently improved service quality, due to the operation of the STIPS.

In each of these circumstances, a DNSP may incur a level of opex that exceeded its allowance, but was nevertheless efficient. It follows that the existence of observed opex that exceeds the regulatory allowance is insufficient to conclude that DNSP has operated inefficiently.

In section 4 I have considered the implications of the AER's draft decision, which profoundly alters the opex incentive arrangements under which ActewAGL's previously operated. In particular, the draft decision:

- rejects ActewAGL's proposed total forecast opex, which was based on its revealed levels of opex and instead relies on the AER's preferred benchmarking model to estimate ActewAGL's base year opex;

- did not apply the negative EBSS carry forward amounts that would have accrued to ActewAGL from the 2009-14 regulatory control period; and

- proposes to abandon the EBSS in the 2015-19 regulatory control period.

The first implication of these changes is retrospectively to change burden of sharing of any opex cost overruns that occurred in the 2009/10-2013/14 regulatory control period, as between ActewAGL and its customers. I explained in section 3 that any differences between ActewAGL's outturn opex and its corresponding regulatory allowance would be shared 30:70 between ActewAGL and its customers, respectively. However, the effect of the draft decision is for ActewAGL to bear 100 per cent of the cost opex overruns. For ActewAGL, outturn opex over the 2009/10-2013/14 regulatory control period was $44.9 million (2013/14 dollars) greater than its opex allowance. The draft decision proposes that this will be fully borne by ActewAGL.

In my opinion, an unanticipated, retrospective change to the regulatory framework that imposes a substantial material negative financial loss to a DNSP materially increases the regulatory risk applying to all network service providers. This cannot be consistent with the NEO. I calculate that, to maintain the intended sharing ratio of 30:70 in net present value terms, would require the AER to add $36.7 million (2013-14 dollars) to ActewAGL's 2014-15 revenues.

Further, the opex incentive arrangements that are proposed to be applied in the 2014/15-2018/19 regulatory control period have a number of wholly undesirable incentive characteristics, ie:

- the DNSP is financially penalised until its expenditure reaches the benchmark level of opex, and so receives no financial reward for any of the efficiency gains achieved to reach benchmark levels; and

- the absence of the EBSS means that the share of any gains achieved beyond benchmark levels retained by a DNSP will depend on the timing of which such outperformance occurs, ie, the DNSP retains 25 per cent of the benefits of outperformance in year 1 and falls to 6 per cent of the benefits of outperformance in year 5.

The deficiencies I have identified suggest that, although it may not be appropriate to apply the current EBSS when revealed costs are no longer being relied upon to set the opex allowance, the absence of any efficiency mechanism has led to incentive arrangements that are deeply flawed.

In my opinion, the proposed incentive arrangements for opex are inconsistent with the long term interests of consumers, because they:

- undermine the incentive for DNSPs to reduce future opex costs, by discouraging businesses from efficiently incurring expenditure to restructure;

- do not provide a continuous incentive when outturn opex is below benchmark levels, and so encourage DNSPs to defer efficiency improvements;

- increase the incentive to capitalise expenditure when opex is above benchmark levels while providing an incentive to substitute capex for opex when below benchmark levels;

- frustrate the incentive to procure demand management services since the penalty for spending additional opex is over three times greater than the reward offered under the CESS for deferring network investments; and

- obstruct the incentive to improve service performance since the penalty for spending additional opex is substantially greater than the reward provided for improved service performance under the STIPS.

In my opinion, the efficiency incentives implied by the opex arrangements set out in the draft decision given undesirable weight to short term, allocative efficiency considerations, such that the achievement of long term dynamic efficiency is undermined. Such an outcome cannot be consistent with the NEO and, in particular, its emphasis on the 'long term' interests of consumers.

6. Declaration

In accordance with the Guidelines, I confirm that I have made all inquiries that I believe are desirable and appropriate, and that no matters of significance that I regard as relevant have, to my knowledge, been withheld from the Court.

Gregory J Houston
19 January 2015

A1. Instructions

Mr Greg Houston
HoustonKemp
Level 40
161 Castlereagh Street
Sydney NSW 2000

9 January 2015

Dear Greg

INTER-RELATIONSHIP BETWEEN OPERATING EXPENDITURE FORECASTS AND THE AER'S EFFICIENCY BENEFIT SHARING SCHEME

ActewAGL Distribution (**ActewAGL**) would like to engage HoustonKemp Economists (HoustonKemp) to provide an expert opinion on the inter-relationship between operating expenditure (**opex**) forecasts and the AER's Efficiency Benefit Sharing Scheme (**EBSS**) and the consistency of the AER's approach to assessing opex forecasts, and to developing and implementing the EBSS, in its guidelines and draft decision on the distribution determination for ActewAGL for the 2015/16 to 2018/19 subsequent regulatory control period published by the AER on 27 November 2014 (**Draft Decision**), with each other and the regime for the economic regulation of distribution services established by the National Electricity Rules (**NER**).

1.   PURPOSE

The purpose of this brief is to set out the nature, scope and purpose of work that ActewAGL is seeking HoustonKemp to undertake. The scope of work is set out in section 3 below.

2.   BACKGROUND

ActewAGL operates and owns the ACT's electricity distribution network. The AER is responsible for the economic regulation of electricity distribution services in the ACT under the National Electricity Law (**NEL**). The AER is required to make distribution determinations for distribution network service providers (**DNSPs**), including ActewAGL under the NER. The constituent decisions on which such a distribution determination is predicated relevantly include:

- a decision on the annual revenue allowance for the DNSP for each regulatory year of the regulatory control period to which the determination relates;

- a decision in which the AER either accepts the DNSP's total opex forecast for that regulatory control period or does not accept that forecast, in which case the AER must determine an estimate of the DNSP's required opex for that period; and

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- a decision on how any applicable EBSS is to apply to the DNSP.[1]

The annual revenue allowance for the DNSP for each regulatory year of the regulatory control period must be determined using a building block approach, under which the building blocks relevantly include:

- the revenue increments or decrements (if any) for that year arising from the application of any EBSS; and

- the forecast opex for that year as accepted or substituted by the AER in making the distribution determination.[2]

In 2012 significant amendments were made to the NER governing the economic regulation of DNSP's through the Australian Energy Market Commission's (**AEMC's**) Rule Determination, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*. As a result of significant changes to the NER in 2012, the AEMC deferred the full regulatory determination process for the 2014/15-2018/19 regulatory control period. As part of the transitional arrangements under the NER,[3] on 16 April 2014 the AER determined a placeholder distribution determination for a transitional regulatory control period (1 July 2014 to 30 June 2015) and is in the process of making a distribution determination for ActewAGL for the 2015/16-2018/19 subsequent regulatory control period.

In making ActewAGL's distribution determination for the subsequent regulatory control period, the AER is required to determine a "notional" annual revenue allowance for the transitional regulatory control period.[4] The AER must adjust ActewAGL's total revenue requirement for the subsequent regulatory control period (1 July 2015 to 30 June 2019) by increasing or decreasing the annual revenue allowance(s) for one or more of the regulatory years of the subsequent regulatory control period.[5] The amount of that adjustment is calculated as the amount of the annual revenue allowance approved for the transitional regulatory control period in its placeholder distribution determination for that period less the amount of the "notional" annual revenue allowance for the transitional regulatory control period determined in the distribution determination for the subsequent regulatory control period (subject to modifications as set out in the AER's Framework and Approach Paper).

ActewAGL submitted its regulatory proposal for the subsequent regulatory control period (2015/16-2018/19) to the AER in July 2014 (**ActewAGL's Subsequent Regulatory Proposal**).[6] The AER published its Draft Decision on 27 November 2014. ActewAGL's revised regulatory proposal is due in January 2015 and the AER expects to publish a final decision in April 2015 in respect of the subsequent regulatory control period (1 July 2015 to 30 June 2019).

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[1] Clause 6.12.1(2), (4) and (9) of the NER.

[2] Clause 6.4.3(a)(5) & (7) and (b)(5) & (7).

[3] Division 2 of Part ZW of Chapter 11 of the NER.

[4] Clause 11.56.4(c) of the NER.

[5] Clause 11.56.4(h) and (i) of the NER.

[6] ActewAGL first submitted its regulatory proposal to the AER on 2 June 2014. The AER issued ActewAGL with a notice under clause 6.9.1(a) of the NER, to resubmit its regulatory proposal on the basis that it was not compliant with the NER. On 10 July 2014, ActewAGL resubmitted its regulatory proposal which addressed the deficiencies identified by the AER.

NER Requirements

The AER is required to accept a DNSP's forecast opex where it is satisfied that the forecast opex for the regulatory control period reasonably reflects the following criteria (**opex criteria**) in clause 6.5.6(c) of the NER[7] being:

- the efficient costs of achieving the opex objectives in clause 6.5.6(a) of the NER (**opex objectives**);

- the costs that a prudent operator would require to achieve the opex objectives; and

- a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

The opex objectives in clause 6.5.6(a) of the NER are to:

- meet or manage the expected demand for standard control services over the regulatory control period;

- comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

- to the extent that there is no applicable regulatory obligation or requirement in relation to:

  - the quality, reliability or security of supply of standard control services; or

  - the reliability or security of the distribution system through the supply of standard control services,

  to the relevant extent:

  - maintain the quality, reliability and security of supply of standard control services; and

  - maintain the reliability and security of the distribution system through the supply of standard control services; and

- maintain the safety of the distribution system through the supply of standard control services.

In deciding whether or not it is satisfied that the forecast opex for the regulatory control period reasonably reflects the opex criteria, the AER must have regard to certain factors specified in clause 6.5.6(e) of the NER, including relevantly:

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[7] Unless otherwise stated, where we refer in these instructions to provisions in Chapter 6 of the NER we are referring to the provisions in Chapter 6 contained in version 58 of the NER. Clause 11.56.4 of the Savings and Transitional Rules in Chapter 11 of the NER provides that except as specified in that clause, "current Chapter 6" governs the making of a distribution determination for the subsequent regulatory control period for NSW and ACT DNSPs. Clause 11.65.2(a) of the NER provides that references to "current Chapter 6" are to be read as Chapter 6 of the NER as in force immediately after the *National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013* came into force. That Rule came into force on 26 September 2013 and version 58 of the NER was the version of the NER in force from 26 September 2013. Accordingly, the NER currently provides that Chapter 6 in version 58 of the NER applies to the making of distribution determinations for NSW and ACT DNSPs for the subsequent regulatory control period. Accordingly, your expert opinion should also be based on the provisions of Chapter 6 in version 58 of the NER.

- the most recent annual benchmarking report that has been published under clause 6.26 of the NER and the benchmark operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period (clause 6.5.6(e)(4));

- the actual and expected operating expenditure of the DNSP during any preceding regulatory control periods (clause 6.5.6(e)(5));

- the relative prices of operating and capital inputs (clause 6.5.6(e)(6));

- the substitution possibilities between opex and capital expenditure (**capex**) (clause 6.5.6(e)(7));

- whether the opex forecast is consistent with any incentive scheme or schemes that apply to the DNSP, including the EBSS published by the AER under clause 6.5.8 of the NER (clause 6.5.6(e)(8); and

- any other factor the AER considers relevant and which the AER has notified the DNSP in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3 is an operating expenditure factor (clause 6.5.6(e)(12).

Under clause 6.5.8(a) of the NER the AER is required to develop and publish an EBSS that provides for a fair sharing between DNSPs and distribution network users of:

- the efficiency gains derived from the opex of DNSPs for a regulatory control period being less than the forecast opex accepted or substituted by the AER for that regulatory control period; and

- the efficiency losses derived from the opex of DNSPs for a regulatory control period being more than the forecast opex accepted or substituted by the AER for that regulatory control period.

In developing and implementing an EBSS, the AER must have regard to (clause 6.5.8(c) of the NER):

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs;

- the need to provide DNSPs with a continuous incentive, so far is consistent with economic efficiency, to reduce opex;

- the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses;

- any incentives that DNSPs may have to capitalise expenditure; and

- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

Under clause 6.12.1 of the NER, a distribution determination is predicated on (amongst others) constituent decisions on:

- the DNSP's current building block proposal in which the AER either approves or refuses to approve the annual revenue requirement of the DNSP, as set out in the building block proposal, for each regulatory year of the regulatory control period (clause 6.12.1(2)(i)); and

- how any applicable EBSS is to apply to the DNSP (clause 6.12.1(9)).

Clause 6.4.3(a) provides that the annual revenue requirement for a DNSP for a regulatory year of a regulatory control period must be determined using a building block approach, under which the building blocks include, amongst other things:

> (5)   the revenue increments or decrements (if any) for that year arising from the application of any efficiency benefit sharing scheme ... - see subparagraph (b)(5)[.]

Clause 6.4.3(b)(5) in turn provides:

> (5)   the revenue increments or decrements referred to in subparagraph (a)(5) are those that arise as a result of the operation of an applicable efficiency benefit sharing scheme ... as referred to in clause 6.5.8 ... [.]

AER's Approach to Assessing Expenditure Forecasts

In 2013, following the significant amendments to the NER in 2012, the AER undertook a Better Regulation program.[8] As part of that program in November and December 2013 the AER published a number of Guidelines, together with Explanatory Statements, relevant to its assessment of DNSP's expenditure proposals. Relevantly, in November 2013, as required by clause 6.2.8(a) of the NER, the AER published the following:

- the AER's *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013 (**Expenditure Forecast Assessment Guideline**); and

- the AER's *Explanatory Statement, Expenditure Forecast Assessment Guideline*, November 2013 (**Expenditure Forecast Assessment Explanatory Statement**).

The Expenditure Forecast Assessment Guideline specifies the approach the AER proposes to use to assess the forecasts of opex and capex that form part of the DNSPs' regulatory proposals and the information the AER requires for the purpose of that assessment.[9] The Guideline is not mandatory and does not bind the AER or DNSPs, however, if the AER makes a distribution determination which is not in accordance with the Guideline, the AER must state its reasons for departing from the Guideline in that determination.[10]

ActewAGL's opex forecasts for the 2015/16-18/19 regulatory period will be assessed by the AER having regard to its Expenditure Forecast Assessment Guideline.

In its Expenditure Forecast Assessment Guideline, the AER states that it prefers to follow a "base-step-trend" approach to assessing most opex.[11] Under this approach, the AER uses a "revealed cost" approach to assessing base opex. It assesses whether opex in the base year is efficient and adjusts the DNSP's revealed costs to remove inefficient costs.

In describing its proposed general approach to assessing DNSP's forecast expenditure, the AER states in its Expenditure Forecast Guideline:[12]

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[8] New EBSS Explanatory Statement, p9.

[9] Clause 6.4.5(a) of the NER.

[10] Clause 6.2.8(c) of the NER.

[11] AER's Expenditure Forecast Guideline, p22.

[12] AER's Expenditure Forecast Guideline, pp7-8.

For recurrent expenditure, we prefer to use revealed (past actual) costs as the starting point for assessing and determining efficient forecasts. If a DNSP operated under an effective incentive framework, actual past expenditure should be a good indicator of the efficient expenditure the NSP requires in the future. The ex-ante incentive regime provides an incentive to improve efficiency (that is, by spending less than the AER's allowance) because DNSPs can retain a portion of cost savings made during the regulatory control period. However, the incentive to spend less than our allowance must not be to the detriment of the quality of the services the DNSP supplies.

Consequently we apply various incentive schemes (such as the efficiency benefit sharing scheme (EBSS), the service target performance incentive scheme (STPIS) and the capital expenditure sharing scheme (CESS)) to provide DNSPs with a continuous incentive to improve their efficiency in supplying electricity services to the standard demanded by consumers.

While we examine revealed costs in the first instance, we must test whether DNSPs have responded to the incentive framework in place. That is, we must determine whether or not the DNSP's revealed costs are efficient. For example, whether the DNSP's past performance was efficient relative to its peers and whether the DNSP has improved its efficiency over time. For this reason, we will assess the efficiency of base year expenditures using our techniques, beginning with economic benchmarking and category analysis, to determine if it is appropriate for us to rely on a DNSP's revealed costs.

...

Our approach for both opex and capex will place greater reliance on benchmarking techniques than we have in the past. We will, for example, use benchmarking to assist us in determining the appropriateness of revealed costs. We will also benchmark DNSPs across standardised expenditure categories to compare relative efficiency.

In describing its approach to assessing opex in its Expenditure Forecast Guideline the AER states:[13]

The 'revealed cost' approach is our preferred approach to assessing base opex. If actual expenditure in the base year reasonably reflects the opex criteria, we will set base opex equal to actual expenditure for those cost categories forecast using the revealed cost approach. We will use a combination of techniques to assess whether base opex reasonably reflects the opex criteria. We will likely assess base year expenditure exclusive of any movements in provisions that occurred in that year.

We intend to not rely on the expenditure of a particular base year when we identify material inefficiencies in that expenditure. In this case, we may adjust the base year or substitute an appropriate base year. When determining whether to adjust or substitute base year expenditure, we will also have regard to whether rewards or penalties accrued under the EBSS will provide for the DNSP and its customers to fairly share efficiency gains or losses.

We will likely apply all of our assessment techniques to identify the presence of material inefficiencies in the chosen base year, and in choosing an alternative. Section 6 [sic 5] details the information we will require to assess base opex.

The EBSS requires an estimate of actual opex for the final year, which we do not typically know at the time of the final determination. Expressing estimated final year expenditure in the following

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[13] AER's Expenditure Forecast Guideline, p22. See also, Expenditure Forecast Expenditure Assessment Explanatory Statement Box 6.1, p92.

form allows the DNSP to retain incremental efficiency gains made after the base year through the EBSS carryover. To the extent the assumption[14] is incorrect the DNSP will still retain incremental efficiency gains but they will be retained through the opex forecast rather than EBSS carryovers. The same estimate will be used to calculate carryovers under the EBSS. Accordingly, we will estimate final year expenditure to be equal to:

$$A_f^* = F_f - (F_b - A_b) + non\text{-}recurrent\ efficiency\ gain_b$$

where:

- A_f^* *is the estimated actual opex in the final year of the preceding regulatory control period*

- F_f *is the determined opex allowance for the final year of the preceding regulatory control period*

- F_b *is the determined opex allowance for the base year*

- A_b *is the amount of actual opex in the base year*

- *non-recurrent efficiency gain$_b$ is the non-recurrent efficiency gain in the base year.*

The AER discusses its approach to assessing opex in section 5 of its Expenditure Forecast Assessment Explanatory Statement. In that section of its Expenditure Forecast Assessment Explanatory Statement, the AER states the following regarding the EBSS:[15]

> *We are now explicitly required to have regard to whether an opex forecast is consistent with any incentive schemes that apply to a NSP. [footnote 268: NER clauses 6.5.6(e)(8) and 6A.6.6(e)(8)]. Consequently, when determining whether to adjust or substitute base year expenditure, we will also have regard to whether rewards or penalties accrued under the EBSS will provide fair sharing of efficiency gains or losses between the NSP and its customers.*
>
> *A NSP should be largely indifferent in the choice of base year. Although a different base year will derive a different opex forecast, any change to the opex forecast should be offset by a similar but opposite change to the increment/decrement accrued under the EBSS. That is, the opex forecast, net of any EBSS carryover, should be similar...*

The AER considers the interaction between incentive frameworks such as the EBSS and its approaches to assessing opex forecasts in section 6 of its Expenditure Forecast Assessment Explanatory Statement. In that section of the Expenditure Forecast Assessment Explanatory Statement, the AER states the following regarding the EBSS:[16]

> *The EBSS shares opex efficiency gains and losses between NSPs and network users. The specific design of the EBSS addresses two issues:*

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[14] This appears to be a reference to the assumption that efficiency gains made in the base year are recurrent. See p96 of the Expenditure Forecast Explanatory Statement.

[15] Expenditure Forecast Assessment Explanatory Statement, p63.

[16] Expenditure Forecast Assessment Explanatory Statement, pp91-92.

1. *If we set forecast opex allowances with reference to revealed costs in a specific year, the NSP has an incentive to increase its expenditure in that year so as to increase its opex allowance in the following regulatory control period.*

2. *Similarly, if we apply a revealed cost forecast, a NSP that is able to reduce (recurrent) expenditure near the beginning of the regulatory control period can retain the benefits of that reduction longer than if it were to reduce expenditure closer to the end of the period. Consequently, incentives weaken over the period.*

The EBSS allows NSPs to retain the benefits of efficiency gains (losses) for the length of the carryover period, typically five years, irrespective of the year NSPs make the gain (loss). This provides NSPs a continuous incentive to pursue efficiency gains over a regulatory control period.

The AER also states in its Expenditure Forecast Assessment Explanatory Statement that it may make adjustments to base opex for two reasons being:[17]

- a DNSP's recurrent expenditure is inefficient compared to its peers; and/or

- a DNSP's base year expenditure is not reflective of efficient recurrent expenditure due to a one-off factor in the base year.

Regarding the efficiency of recurrent opex and the EBSS, the AER states in its Expenditure Forecast Assessment Explanatory Statement:[18]

As stated, we will use a single year revealed cost forecasting approach to assess opex forecasts. However, if the base year opex reflects inefficient costs, then continuing with a revealed cost approach may not result in a prudent, efficient forecast of costs consistent with the opex criteria. This situation may arise because a NSP does not respond to incentives or appropriate incentives were not in place for efficient expenditure decisions.

Where a NSP does not respond to incentives, the sharing of rewards or penalties would not be in the long term interests of consumers. Where a NSP responds to incentives, it will make efficient expenditure decisions regardless of the forecast. These efficient (historic) expenditures can then be used as the basis for opex forecasts.

Where there is an EBSS in place, there is a continuous incentive across a regulatory period for a NSP to pursue efficiency gains. Hence, when there is an EBSS in place and a NSP appropriately responds to incentives, revealed costs provide a good indication that forecasts will be efficient.

However, we will not assume a NSP is appropriately responding to incentives simply because an EBSS is in place. We must test the NSP's efficiency before relying on its revealed costs. We will likely use a number of techniques to assess the efficiency of a NSP's base year, including economic benchmarking techniques.

In its Expenditure Forecast Assessment Explanatory Statement the AER also considered whether the assumption, which was made in the Old EBSS, that all efficiency gains made in the base year were

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[17] Expenditure Forecast Expenditure Assessment Explanatory Statement p93.

[18] Expenditure Forecast Assessment Explanatory Statement, pp94-95.

recurrent was necessary.[19] That is, whether it was necessary for the EBSS to assume that the underspend in the final year of the regulatory control period was equal to any observed underspend in the base year. The AER noted that if that assumption was made it was important that the opex forecasting approach reflected the same assumption. However, the AER considered that the assumption may not always be appropriate. It noted that:[20]

> If base year expenditure was significantly lower (higher) than ongoing efficient opex, due to a one-off factor, then the opex forecast would be artificially low (high). The NSP would be sufficiently compensated through the EBSS carryover, however the 'optics' could be misleading. That is, an NSP's actual expenditure would appear high when compared against its regulatory allowance (not factoring in the EBSS carryover).

The AER concluded that it was not necessary for the EBSS to assume that all efficiency gains made in the base year were recurrent. Accordingly, it decided to relax that assumption in its approach to the opex forecast and the New EBSS. The AER stated:[21]

> We have reconsidered whether it is necessary to make this assumption in both the opex forecast and the EBSS. We have determined this assumption is not necessary as long as the same assumption about final year expenditure is made in both the EBSS and opex forecast. Given this, we have relaxed the assumption that all efficiency gains made in the base year are recurrent. The estimated final year equation (which we previously called the deemed final year equation) now allows one-off efficiency gains in the base year to be added back on to the estimated final year opex to ensure if reflects efficient ongoing expenditure and is not artificially low. To ensure NSPs have a continuous incentive in the final year, we have made a corresponding adjustment to the EBSS. This effectively shifts revenue from the EBSS carryover to the opex forecast.

The AER's EBSS

The AER's *ActewAGL Distribution distribution determination 2009-10 to 2013-14* dated 28 April 2009 (**Distribution Determination**) includes the AER's constituent decision on how any applicable EBSS was to apply to ActewAGL in the previous regulatory control period.[22] The Distribution Determination provided that the EBSS to apply to ActewAGL in the previous regulatory control period would be the EBSS applicable to NSW and ACT DNSPs published by the AER in February 2008 titled *Efficiency benefit sharing scheme for the ACT and NSW distribution determinations* under clause 6.5.8 of Transitional Chapter 6 (**Old EBSS**).[23] Accordingly, ActewAGL's carryover amounts arising from the 2009/10-13/14 regulatory control period for the purposes of the AER's distribution determination for ActewAGL for the subsequent regulatory control period are to be calculated in accordance with the AER's Old EBSS.

Also as part of the AER's Better Regulation Program, in November 2013, in accordance with clause 6.5.8(a) of the NER, the AER published a new version of the EBSS that will apply to distribution determinations in respect of regulatory control periods commencing after November 2013. The AER published the following:

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[19] Expenditure Forecast Assessment Explanatory Statement, pp95-96.

[20] Expenditure Forecast Assessment Explanatory Statement, p96.

[21] Expenditure Forecast Assessment Explanatory Statement, p96.

[22] This constituent decision was required to be made in ActewAGL's Distribution Determination by clause 6.12.1(9) of Chapter 6 in the form set out in Appendix 1 to the NER (**Transitional Chapter 6**). See also clause 6.3.2(a)(3) of Transitional Chapter 6, which requires the building block determination that is a component of a distribution determination (see clause 6.3.1(a)) to specify, for a regulatory control period, how any applicable EBSS is to apply to the DNSP. Transitional Chapter 6 applies to the NSW and ACT DNSPs in respect of the previous regulatory control period (Division 2 of Part M - Economic Regulation of Distribution Services (2007 Amendments)).

[23] Distribution Determination, p7.

- the AER's *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013 (**New EBSS**); and

- the AER's *Explanatory Statement, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013 (**New EBSS Explanatory Statement**).

Consistent with its approach in the Expenditure Forecast Assessment Guideline and the Expenditure Forecast Assessment Explanatory Statement, in its New EBSS Explanatory Statement, the AER states the following about the EBSS and its approach to assessing base year expenditure:[24]

> *The EBSS aims to provide a continuous incentive for NSPs to pursue efficiency improvements in opex and to share efficiency gains between NSPs and network users. It is intrinsically linked to our forecasting approach for opex. In our Expenditure Forecast Assessment Guidelines, we have stated our preference is to continue with the revealed cost base-step-trend forecasting approach for assessing opex. If a NSP has operated under an effective incentive framework, and sought to maximise its profits, the actual opex incurred in a base year should be a good indicator of the efficient opex required. However, we must test this, and if we determine a NSP's revealed costs are not efficient, we will adjust them to remove inefficient costs. We then add additional opex not reflected in the base year ('step changes') and trend it forward to reflect forecast changes in input costs, productivity and output growth.*

Further, in the New EBSS Explanatory Statement, the AER states that:[25]

> *Our Explanatory Statement to the draft EBSS noted that when we use a single year revealed cost forecasting method NSPs face strong incentives to overspend in the expected base year. The EBSS is designed to counter this incentive. Although the EBSS has only been in place a short time, there is not strong evidence to suggest spending in the base year has been high compared to other years. As we are likely to continue to use a single year revealed cost forecasting method for forecasting opex, we considered that a mechanism is required to mitigate a NSP's incentive to increase opex in the expected base year. A NSP may still have this incentive even if it expects we may adjust the base year to remove identified inefficiencies (we will test the efficiency of base year expenditure and adjust it if we find it to be inefficient). Our draft position was that the EBSS is an effective mechanism for constraining this incentive.*

ActewAGL's approach to forecasting opex and the EBSS

For the 2014-19 regulatory period, ActewAGL has used the fourth year (2012-13) of the previous regulatory control period as the base year for forecasting opex where using a base year approach. Further details of ActewAGL's forecasting approach are contained in ActewAGL's Subsequent Regulatory Proposal (see section 8.7, from page 222).

ActewAGL sets out how it considers the EBSS should apply to it in Chapter 16 of its Subsequent Regulatory Proposal.[26]

AER's conclusions on forecast opex and the EBSS in its Draft Decision

AER's draft decision on forecast opex

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[24] New EBSS Explanatory Statement p6.

[25] New EBSS Explanatory Statement p15.

[26] ActewAGL's Subsequent Regulatory Proposal, pp356-360.

The AER concluded in the Draft Decision that it was not satisfied ActewAGL's forecast opex reasonably reflected the opex criteria. Accordingly, the AER rejected the forecast opex included in ActewAGL's building block proposal. The AER substituted ActewAGL's total opex forecast with the AER's total opex forecast, which it considered reasonably reflected the opex criteria.[27] The AER's draft decision in respect of opex is contained in Attachment 7 to the Draft Decision.

In assessing ActewAGL's forecast opex, the AER generally followed the approach set out in its Expenditure Forecast Assessment Guideline and Expenditure Forecast Assessment Explanatory Statement. Like ActewAGL, the AER used 2012-13 as the base year for its opex forecast, subject to its considerations in respect of efficiency adjustments.[28]

The AER concluded that the main difference between its opex forecast and ActewAGL's forecast was the portion of opex in the base year that was efficient.[29] The AER's detailed analysis of ActewAGL's base year opex is contained in Appendix A to Attachment 7 to the Draft Decision.

In assessing base year opex, under clause 6.5.6(e)(12) of the NER the AER took into account the following two opex factors in addition to the factors specified in clauses 6.5.6(e)(4) to 6.5.6(e)(10):[30]

- the AER's benchmarking data sets including, but not limited to:

    o data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN;

    o any relevant data from international sources; and

    o data sets that support econometric modelling and other assessment techniques consistent with the approach in the AER's Expenditure Forecast Assessment Guideline,

  as updated from time to time; and

- economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.

The AER tested the efficiency of ActewAGL's historical opex using a combination of assessment techniques, including economic benchmarking. For the purpose of its Draft Decision and its distribution determinations in respect of NSW DNSPs, the AER engaged Economic Insights Pty Ltd (**Economic Insights**) to assist with the application of economic benchmarking and advise on:[31]

- whether the AER should make adjustments to base opex for the NSW and ACT DNSPs based on the results from economic benchmarking models; and

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[27] Overview to Draft Decision, p51 and Attachment 7, p7-7.

[28] Attachment 7, p7-36.

[29] Overview to Draft Decision, p51.

[30] Attachment 7, p7-11 and p7-24.

[31] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014 (**Economic Insights Report**), piv. While the Draft Decision refers to an Economic Insights Report of October 2014 (see for example, footnote 35 of Appendix 7), the 17 November 2014 report is the report provided on the AER's website in connection with the Draft Decision. Accordingly, the references in this letter are to that report.

- the productivity change to be applied to forecast opex for the NSW and ACT DNSPs.

In its report, Economic Insights use a range of economic benchmarking methods to assess the relative opex cost efficiency of Australian DNSPs, including a Cobb Douglas stochastic frontier analysis opex cost function model, Cobb Douglas and Translog least squares econometrics (LSE) opex cost function models and multilateral total factor productivity (MTFP) and mutilateral partial factor productivity (MPFP) indexes.[32]

In assessing base year opex in the Draft Decision, the AER relied on the analysis in the Economic Insights Report to compare ActewAGL to its peers using those benchmarking techniques. The benchmarking results are described in Appendix A of Attachment 7 to the Draft Decision. The AER found that the benchmarking analysis undertaken by Economic Insights revealed that ActewAGL spends opex about 40 per cent as efficiently as the most efficient service providers in the NEM (CitiPower and Powercor) on four different measures.[33] The AER considered that other simpler benchmarking techniques such as partial performance indicators and category analysis corroborated those results.[34]The AER also examined potential sources of inefficiency or high costs that might explain the gap in performance between ActewAGL and its peers. This included consideration of ActewAGL's labour and workforce practices and vegetation management.[35]

Following its analysis of ActewAGL's forecast opex, the AER concluded that it was satisfied that it did not reasonably reflect the opex criteria and, accordingly, an adjustment was necessary. On the advice of Economic Insights the AER used results from its preferred benchmarking model, the Cobb Douglas Stochastic Frontier Analysis model, as a starting point for determining an alternative estimate of what it considered reasonably reflected base year opex.[36] However, rather than mechanistically applying the efficiency adjustment predicted by the model, the AER made three adjustments to the "raw" benchmarking results in favour of ActewAGL. The AER describes those adjustments in Attachment 7 to the Draft Decision as follows:[37]

> Rather than using the National Energy Market (NEM) frontier service provider, CitiPower, as the benchmark for efficiency comparisons, the first adjustment is to set a lower benchmark based on an average of the efficiency scores of the most efficient service providers in the NEM. This reduces the benchmark efficiency target by 9 percentage points to 0.86 from 0.95.
>
> The second adjustment is to modify the benchmark efficiency target to account for operating environment factors specific to the ACT. We are satisfied that a 30 per cent operating environment adjustment is appropriate for ActewAGL. This effectively reduces the benchmark efficiency target by 20 percentage points to 0.66.
>
> Additionally we have made a third adjustment because the Cobb Douglas SFA model efficiency scores represent ActewAGL's average efficiency for the benchmarking period. We have applied a trend to move the substitute base opex from a forecast of the average amount for the 2006 to 2013 period to a forecast for 2012–13, the base year. In trending the average amount forward,

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[32] Economic Insights Report, piv and Draft Decision, pp7-52 to 7-61.

[33] Overview to Draft Decision, p52 and Attachment 7, pp7-26 to 7-27.

[34] Overview to Draft Decision, p52 and Attachment 7, pp7-29 to 7-31, pp7-61 to 7-64 and p7-70.

[35] Overview to Draft Decision, p52 and Attachment 7 pp7-31 to 7-33 and pp7-77 to 7-89.

[36] Attachment 7, p 7-19, p7.27.

[37] Attachment 7, p7-27. See also Attachment 7, pp7-123 to 7-125. Further, the AER describes its analysis in respect of operating environment factors that require adjustments to the benchmarking results at pp7-90 to 7-122 of the Attachment 7 to the Draft Decision.

we have used essentially the same rate of change method we use to determine the trend component of our base step trend methodology. For this reason, the percentage reduction differs to the average efficiency score.

AER's draft decision on the EBSS

The AER's draft decision was not to apply an EBSS carryover penalty to ActewAGL arising from the application of the Old EBSS during the 2009/10-13/14 regulatory control period.[38] In addition, the AER's draft decision was that no expenditure would be subject to the New EBSS during the 2014/15-18/19 period. The AER's draft decision in respect of the EBSS is contained in Attachment 9 to the Draft Decision.

The AER stated that, under the EBSS, the fair sharing of efficiency gains and losses in one regulatory control period was intrinsically linked to the use of a revealed cost forecasting approach for opex for the following regulatory control period.[39] The AER considered that where it does not propose to rely on the revealed costs of a service provider in forecasting opex that had consequences for the service provider's incentives to make productivity improvements and, as a consequence, for its decision on how the AER applies the EBSS.

Consistently with ActewAGL's calculation in its Subsequent Regulatory Proposal, the AER estimated that if it applied the carryover amounts arising from the application of the Old EBSS in the 2009/10-13/14 regulatory control period in determining ActewAGL's annual revenue allowances for the 2014/15-2018/19 period, ActewAGL would receive an EBSS carryover penalty of -$19.6 million.[40] The AER considered that given that it had not used a revealed cost approach to forecasting ActewAGL's opex and had adjusted ActewAGL's base opex down in its alternative forecast after benchmarking it against other DNSPs, if it were to apply both the EBSS penalty and a benchmark opex allowance for the 2014/15-2018/19 period derived in this manner, ActewAGL would carry a greater share of efficiency losses than was intended when the AER decided to apply the Old EBSS in the 2009-14 regulatory control period. Accordingly, the AER considered that applying the Old EBSS would not give effect to the objectives of fair sharing of efficiency losses as defined under the NER.[41]

The AER said:[42]

> *We acknowledge that this is a different position to what we considered we would do when we established the EBSS. We originally intended to apply all EBSS carryover amounts - both positive and negative. However, at the same time, we also highlighted the inter-relationships between the EBSS and a revealed cost forecasting approach. For instance, we considered we were likely to be relying on revealed costs to some degree to forecast ActewAGL's opex in the next period.*
>
> *When implementing an efficiency benefit sharing scheme, we have regard to whether benefits to electricity consumers from the scheme are sufficient to warrant a penalty we might apply under the scheme. As we have not used a revealed cost forecasting approach for this draft decision, we have revisited our earlier position that all negative EBSS carryover amounts should apply when implementing the EBSS. A change in opex forecasting approach away from a revealed cost*

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[38] Overview to Draft Decision, pp61-62; Attachment 9, p9-7.

[39] Attachment 9, p9-8.

[40] Attachment 9, p9-9.

[41] Attachment 9, p9-10.

[42] Attachment 9, pp9-10 to 9-11.

approach leads to different sharing of efficiency losses than was intended when we established the EBSS. We do not believe a carryover penalty is warranted in these circumstances.

The AER noted that it made this draft decision on the application of the Old EBSS only because of its change in forecasting approach, and that it intended to apply negative EBSS carryover amounts to other service providers where it relied on a revealed cost forecasting approach.[43]

> The AER concluded that because it was uncertain whether, and to what extent, it would rely on ActewAGL's revealed costs in the 2014/15-2018/19 period in forecasting its opex in the following regulatory control period, its draft decision was that no expenditure would be subject to the New EBSS during that period. The AER considered that if it did not use a revealed cost forecasting approach for forecasting opex in the future, there was not a strong reason to apply the New EBSS.[44] The AER stated that:[45] *In the case where we apply the EBSS in the 2015–19 regulatory control period but do not rely on revealed costs to set forecast opex in the next regulatory control period, there are some potentially perverse outcomes. For instance a service provider will face high penalties if it continues to make incremental efficiency losses. It will receive negative EBSS carryovers as well as a benchmark opex allowance. This outcome is not consistent with what we are seeking to achieve with the application of the EBSS nor is it consistent with the implementation requirements for an EBSS set out in the NER.*

Further, the AER considered that since ActewAGL would already face an incentive to make efficiency improvements while its actual opex was higher than that of a benchmark efficient service provider, it did not need to apply an EBSS to further strengthen its incentives.[46]

3.   SCOPE OF WORK

ActewAGL is seeking an expert opinion on the inter-relationship between opex forecasts and the AER's EBSS and whether the AER's approach to assessing opex forecasts is consistent with that EBSS, having regard in particular to the requirements of the NER.

The consultant is to provide an expert report which addresses the following:

- The effect of making adjustments to base year opex on the basis that a DNSP's expenditure is inefficient relative to its peers on:

    o   the DNSP's resultant incentives under the EBSS to realise efficiency gains; and

    o   the sharing of efficiency gains between DNSPs and network users.

- Whether appropriate incentives were in place in the 2009/10-2013/14 regulatory control period for ActewAGL to make efficient opex decisions in that period including in particular in the base year. That is, whether the application of the Old EBSS to ActewAGL in that period created appropriate and effective efficiency incentives.

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[43] Attachment 9, p9-11.

[44] Attachment 9, p9-11.

[45] Attachment 9, p9-12.

[46] Attachment 9, p9-12.

- If the Old EBSS created appropriate and effective incentives in the previous period for efficient opex decisions by ActewAGL, the circumstances in which it would not respond appropriately to those incentives.

- The effect of a decision by the AER, in making its distribution determination for ActewAGL for the 2015/16-2018/19 subsequent regulatory control period, not to apply the carryover amounts for the 2014/15-2018/19 period arising from the application of the Old EBSS to ActewAGL in the 2009/10-2013/14 regulatory control period on the sharing between ActewAGL and distribution network users of the amount by which ActewAGL's opex for that period exceeded the forecast opex determined by the AER for that period.

- Whether and the extent to which a decision by the AER, in making its distribution determination for ActewAGL for the 2015/16-2018/19 subsequent regulatory control period, to determine opex forecasts for the 2014/15-2018/19 period otherwise than by reference to a revealed cost approach and also apply the carryover amounts for the 2014/15-2018/19 period arising from the application of the Old EBSS to ActewAGL in the 2009/10-2013/14 regulatory control period would be consistent with the regime for the economic regulation of distribution services established by Chapter 6 of the NER, the objective of the EBSS set out in clause 6.5.8(a) of the NER and the matters set out in clause 6.5.8(c) of the NER.

- Whether and the extent to which a decision by the AER, in making its distribution determination for ActewAGL for the 2015/16-2018/19 subsequent regulatory control period, to determine opex forecasts for the 2014/15-2018/19 period otherwise than by reference to a revealed cost approach and not to apply any EBSS to ActewAGL in that period would be consistent with the regime for the economic regulation of distribution services established by Chapter 6 of the NER, the object of the EBSS set out in clause 6.5.8(a) of the NER and the matters set out in clause 6.5.8(c) of the NER.

- In addressing the foregoing, the consultant is asked to address (amongst other things) the effects of a decision by the AER, in making its distribution determination for ActewAGL for the 2015/16-2018/19 subsequent regulatory control period, to determine opex forecasts for the 2014/15-2018/19 period otherwise than by reference to a revealed cost approach and not to apply any EBSS to ActewAGL in that period on:

    o ActewAGL's incentives to reduce opex in the 2014/15-2018/19 period; and

    o the sharing between ActewAGL and distribution network users of the amount by which ActewAGL's opex for the 2014/15-2018/19 period is more or less than the forecast opex determined by the AER for that period.

- Any other matters the expert considers relevant to the interrelationship between the approach to forecasting opex and the operation of the EBSS, or the assessment of the efficiency of base year opex.

For the purpose of preparation of the report, we will provide you with a copy of the documents listed in Attachment A to this letter.

A list of all documents provided to HoustonKemp, as well as those documents relied upon by HoustonKemp should be included in the report and those documents should be annexed to the report or, in the alternative, provided to ActewAGL if they were not provided to HoustonKemp by ActewAGL. In addition, you should attach a copy of your CV containing your qualifications and relevant experience to your expert report.

4. EXPERT WITNESSES

ActewAGL anticipates providing a copy of HoustonKemp's report to the AER in response to the AER's Draft Decision.

To this end, ActewAGL has attached a copy of the Federal Court of Australia's Practice Note "Expert Witnesses in Proceedings in the Federal Court of Australia" (**Attachment B**). The Practice Note contains useful direction regarding the steps that should be taken by expert witnesses to ensure the veracity of their reports. ActewAGL requires HoustonKemp to comply with the Practice Note in preparing its report.

5. TIMING

HoustonKemp must deliver its final report by 19 January 2015.

6. Contact

Usman Saadat, Manager, Regulatory Affairs, will be the day to day contact for HoustonKemp in relation to this project. Usman's contact details are:

Usman Saadat
ActewAGL Regulatory Affairs
Phone: 02 6248 3806
Email:Usman.Saadat@actewagl.com.au

Please contact Usman if you have any questions regarding the preparation of your report.

Yours sincerely

David Graham
Director, Regulatory Affairs and Pricing

Attachment A

List of documents

1. ActewAGL's regulatory proposal for the subsequent regulatory control period (2015-2019) (resubmitted 10 July 2014).

2. AER, *Draft decision ActewAGL distribution determination 2015/16 to 2018/19* published on 27 November 2014 (**Draft Decision**), Overview.

3. AER, Draft Decision, Attachment 7: Operating Expenditure.

4. AER, Draft Decision, Attachment 9: Efficiency Benefit Sharing Scheme.

5. AER, Draft Decision, Attachment 10: Capital Expenditure Sharing Scheme

6. AER, Draft Decision, Attachment 11: STPIS

7. Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014.

8. AER, *Electricity distribution network service providers, Annual benchmarking report*, November 2014.

9. Chapter 6 in the form set out in Appendix 1 to the National Electricity Rules.

10. Chapter 6 in version 58 of the National Electricity Rules.

11. Chapter 6 and Chapter 10 in version 66 of the National Electricity Rules.

12. Divisions 1 and 2 of Part M, Division 2 of Part ZW and Part ZY of Chapter 11 in version 66 of the National Electricity Rules.

13. AER, *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013.

14. AER, *Explanatory Statement, Expenditure Forecast Assessment Guideline*, November 2013.

15. AER, *Electricity Distribution Network Service Providers Efficiency Benefit Sharing Scheme*, June 2008.

16. AER, *Electricity Distribution Network Service Providers Efficiency Benefit Sharing Scheme, Final Decision,* June 2008.

17. AER, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.

18. AER, *Explanatory Statement, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.

Attachment B

Federal Court's Practice Note CM 7
"Expert Witness Proceedings in the Federal Court of Australia"

Appended separately.

FEDERAL COURT OF AUSTRALIA
Practice Note CM 7
EXPERT WITNESSES IN PROCEEDINGS IN THE
FEDERAL COURT OF AUSTRALIA

Practice Note CM 7 issued on 1 August 2011 is revoked with effect from midnight on 3 June 2013 and the following Practice Note is substituted.

Commencement
1.   This Practice Note commences on 4 June 2013.

Introduction
2.   Rule 23.12 of the Federal Court Rules 2011 requires a party to give a copy of the following guidelines to any witness they propose to retain for the purpose of preparing a report or giving evidence in a proceeding as to an opinion held by the witness that is wholly or substantially based on the specialised knowledge of the witness (see **Part 3.3 - Opinion** of the *Evidence Act 1995* (Cth)).

3.   The guidelines are not intended to address all aspects of an expert witness's duties, but are intended to facilitate the admission of opinion evidence[1], and to assist experts to understand in general terms what the Court expects of them.   Additionally, it is hoped that the guidelines will assist individual expert witnesses to avoid the criticism that is sometimes made (whether rightly or wrongly) that expert witnesses lack objectivity, or have coloured their evidence in favour of the party calling them.

Guidelines
1.   General Duty to the Court[2]
1.1   An expert witness has an overriding duty to assist the Court on matters relevant to the expert's area of expertise.

1.2   An expert witness is not an advocate for a party even when giving testimony that is necessarily evaluative rather than inferential.

1.3   An expert witness's paramount duty is to the Court and not to the person retaining the expert.

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[1] As to the distinction between expert opinion evidence and expert assistance see *Evans Deakin Pty Ltd v Sebel Furniture Ltd* [2003] FCA 171 per Allsop J at [676].
[2] The *"Ikarian Reefer"* (1993) 20 FSR 563 at 565-566.

2. The Form of the Expert's Report[3]

2.1 An expert's written report must comply with Rule 23.13 and therefore must

    (a) be signed by the expert who prepared the report; and

    (b) contain an acknowledgement at the beginning of the report that the expert has read, understood and complied with the Practice Note; and

    (c) contain particulars of the training, study or experience by which the expert has acquired specialised knowledge; and

    (d) identify the questions that the expert was asked to address; and

    (e) set out separately each of the factual findings or assumptions on which the expert's opinion is based; and

    (f) set out separately from the factual findings or assumptions each of the expert's opinions; and

    (g) set out the reasons for each of the expert's opinions; and

    (ga) contain an acknowledgment that the expert's opinions are based wholly or substantially on the specialised knowledge mentioned in paragraph (c) above[4]; and

    (h) comply with the Practice Note.

2.2 At the end of the report the expert should declare that "[the expert] has *made all the inquiries that* [the expert] *believes are desirable and appropriate and that no matters of significance that* [the expert] *regards as relevant have, to* [the expert's] *knowledge, been withheld from the Court.*"

2.3 There should be included in or attached to the report the documents and other materials that the expert has been instructed to consider.

2.4 If, after exchange of reports or at any other stage, an expert witness changes the expert's opinion, having read another expert's report or for any other reason, the change should be communicated as soon as practicable (through the party's lawyers) to each party to whom the expert witness's report has been provided and, when appropriate, to the Court[5].

2.5 If an expert's opinion is not fully researched because the expert considers that insufficient data are available, or for any other reason, this must be stated with an indication that the opinion is no more than a provisional one. Where an expert witness who has prepared a report believes that it may be incomplete or inaccurate without some qualification, that qualification must be stated in the report.

2.6 The expert should make it clear if a particular question or issue falls outside the relevant field of expertise.

2.7 Where an expert's report refers to photographs, plans, calculations, analyses, measurements, survey reports or other extrinsic matter, these must be provided to the opposite party at the same time as the exchange of reports[6].

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[3] Rule 23.13.

[4] See also *Dasreef Pty Limited v Nawaf Hawchar* [2011] HCA 21.

[5] The *"Ikarian Reefer"* [1993] 20 FSR 563 at 565

[6] The *"Ikarian Reefer"* [1993] 20 FSR 563 at 565-566. See also Ormrod *"Scientific Evidence in Court"* [1968] Crim LR 240

3. Experts' Conference

3.1 If experts retained by the parties meet at the direction of the Court, it would be improper for an expert to be given, or to accept, instructions not to reach agreement. If, at a meeting directed by the Court, the experts cannot reach agreement about matters of expert opinion, they should specify their reasons for being unable to do so.

J L B ALLSOP
Chief Justice
4 June 2013

A2. Curriculum Vitae

Greg Houston

Partner

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Mobile: +61 417 237 563
E-mail: Greg.Houston@houstonkemp.com
Web: HoustonKemp.com

Overview

Greg Houston is a founding partner of the firm of expert economists, HoustonKemp. He has twenty five years' experience in the economic analysis of markets and the provision of expert advice in litigation, business strategy, and policy contexts. His career as a consulting economist was preceded by periods working in a financial institution and for government.

Greg has directed a wide range of financial, competition and regulatory economics assignments during this consulting career. His work in the Asia Pacific region principally revolves around the activities of the enforcement and regulatory agencies responsible for these areas, many of whom also number amongst his clients. In his securities and finance work Greg has advised clients on a number of securities class action, market manipulation and insider trading proceedings, as well as on cost of capital estimation. On competition and antitrust matters he has advised clients on merger clearance processes, competition proceedings involving allegations of anticompetitive conduct ranging from predatory pricing, anti-competitive agreements, anti-competitive bundling and price fixing. Greg also has deep experience of infrastructure access regulation matters, and intellectual property and damages valuation.

Greg's industry experience spans the aviation, beverages, building products, cement, e-commerce, electricity and gas, forest products, grains, medical waste, mining, payments networks, petroleum, ports, rail transport, retailing, scrap metal, securities markets, steel, telecommunications, thoroughbred racing, waste processing and water sectors.

Greg has acted as expert witness in valuation, antitrust and regulatory proceedings before the courts, in various arbitration and mediation processes, and before regulatory and judicial bodies in Australia, Fiji, New Zealand, the Philippines, Singapore, the United Kingdom and the United States.

Greg was until April 2014 a Director of the global firm of consulting economists, NERA Economic Consulting where, for twelve years he served on its United State Board of Directors, for five years on its global Management Committee and for sixteen years as head of its Australian operations. Greg also serves on the Competition and Consumer Committee of the Law Council of Australia.

Qualifications
1982   **UNIVERSITY OF CANTERBURY, NEW ZEALAND**
                B.Sc. (First Class Honours) in Economics

Prizes and Scholarships
1980   University Junior Scholarship, New Zealand

Career Details

1989-2014	**NERA ECONOMIC CONSULTING** Director (2000-2014) London, United Kingdom (1989-1997); and Sydney, Australia (1998-2014)
1987-89	**HAMBROS BANK, TREASURY AND CAPITAL MARKETS** Financial Economist, London, United Kingdom
1983-86	**THE TREASURY, FINANCE SECTOR POLICY** Investigating Officer, Wellington, New Zealand

Project Experience

Regulatory Analysis

2014	**Actco Gas** **Access price review** Expert reports on the economic interpretation of provisions in the national gas law and rules in relation to depreciation and the application of the national gas objective to the entire draft decision, submitted to the Economic Regulation Authority of WA.
2014	**Government of Victoria** **Economic regulation for privatisation** Advisor to government of Victoria on the economic regulation of the Port of Melbourne Corporation in the context of the proposed privatization of the port by way of long term lease.
2013	**Actew Corporation** **Interpretation of economic terms** Advice on economic aspects of the draft and final decisions of the Independent Competition and Regulatory Commission in relation to the price controls applying to Actew.
2012-13	**Gilbert + Tobin/Rio Tinto Coal Australia** **Price review arbitration** Analysis and expert reports prepared in the context of an arbitration concerning the price to be charged for use of the coal loading facilities at Abbott Point Coal Terminal.
2012-13	**Ashurst/Brisbane Airport Corporation** **Draft access undertaking** Advice, analysis and expert reports in the context of the preparation of a draft access undertaking specifying the basis for determining a ten year price path for landing charges necessary to finance a new parallel runway at Brisbane airport.
2012	**King & Wood Mallesons/Origin Energy** **Interpretation of economic terms** Expert reports and testimony in the context of judicial review proceedings before the Supreme Court of Queensland on the electricity retail price determination of the Queensland Competition Authority.
2012	**Contact Energy, New Zealand** **Transmission pricing methodology** Advice on reforms to the Transmission Pricing Methodology proposed by Electricity Authority.

2011-12   **Energy Networks Association**
                     Network pricing rules
                     Advice and expert reports submitted to the Australian Energy Market
                     Commission on wide-ranging reforms to the network pricing rules applying to
                     electricity and gas transmission and distribution businesses, as proposed by
                     the Australian Energy Regulator.

2010-12   **QR National**
                     Regulatory and competition matters
                     Advisor on the competition and regulatory matters, including: a range of
                     potential structural options arising in the context of the privatisation of QR
                     National's coal and freight haulage businesses, particularly those arising in
                     the context of a 'club ownership model' proposed by a group of major coal
                     mine owners; and an assessment of competitive implications of proposed
                     reforms to access charges for use of the electrified network.

2002-12   **Orion New Zealand Ltd, New Zealand**
                     Electricity lines regulation
                     Advisor on regulatory and economic aspects of the implementation by the
                     Commerce Commission of the evolving regimes for the regulation of New
                     Zealand electricity lines businesses. This role has included assistance with
                     the drafting submissions, the provision of expert reports, and the giving of
                     expert evidence before the Commerce Commission.

2011   **Meridian Energy, New Zealand**
                     Undesirable trading situation
                     Advice to Meridian Energy on the economic interpretation and implications of
                     the New Zealand electricity rule provisions that define an 'undesirable trading
                     situation' in the wholesale electricity market.

2011   **Ausgrid**
                     Demand side management
                     Prepared a report on incentives, constraints and options for reform of the
                     regulatory arrangements governing the role of demand side management in
                     electricity markets.

2010-11   **Transnet Corporation, South Africa**
                     Regulatory and competition policy
                     Retained to advise on the preparation of a white paper on future policy and
                     institutional reforms to the competitive and regulatory environment applying to
                     the ports, rail and oil and gas pipeline sectors of South Africa.

2010-11   **Minter Ellison/UNELCO, Vanuatu**
                     Arbitral review of decision by the Vanuatu regulator
                     Expert report and evidence before arbitrators on a range of matters arising
                     from the Vanuatu regulator's decision on the base price to apply under four
                     electricity concession contracts entered into by UNELCO and the Vanuatu
                     government. These included the estimation of the allowed rate of return
                     including its country risk component, and the decision retrospectively to bring
                     to account events from the prior regulatory period.

2007-11   **Powerco/CitiPower**
                     Regulatory advice
                     Wide ranging advice on matters arising under the national electricity law and
                     rules, such as the framework for reviewing electricity distribution price caps,
                     the treatment of related party outsourcing arrangements, an expert report on
                     application of the AER's efficiency benefit sharing scheme, the potential
                     application of total factor productivity measures in CPI-X regulation, and
                     arrangements for the state-wide roll out of advanced metering infrastructure.

1999-2004, 2010-11	**Sydney Airports Corporation** **Aeronautical pricing notification** Wide ranging advice on regulatory matters. This includes advice and expert reports in relation to SACL's notification to the ACCC of substantial reforms to aeronautical charges at Sydney Airport in 2001. This involved the analysis and presentation of pricing principles and their detailed application, through to discussion of such matters at SACL's board, with the ACCC, and in public consultation forums. Subsequent advice on two Productivity Commission reviews of airport charging, and notifications to the ACCC on revised charges for regional airlines.
2010	**Industry Funds Management/Queensland Investment Corporation** **Due diligence, Port of Brisbane** Retained to advise on regulatory and competition matters likely to affect the future financial and business performance of the Port of Brisbane, in the context of its sale by the Queensland government.
2009-10	**New Zealand Electricity Industry Working Group, New Zealand** **Transmission pricing project** Advice to a working group comprising representatives from lines companies, generators, major users and Transpower on potential improvements to the efficiency of New Zealand's electricity transmission pricing arrangements.
2007-09	**GDSE, Macau** **Electricity tariff reform** Advice to the regulator of electricity tariffs in Macau on a series of potential reforms to the structure of electricity supply tariffs.
2001-09	**Auckland International Airport Limited, New Zealand** **Aeronautical price regulation** Advice and various expert reports in relation to: the review by the Commerce Commission of the case for introducing price control at Auckland airport; a fundamental review of airport charges implemented in 2007; and the modified provisions of Part IV of the Commerce Act concerning the economic regulation of airports and other infrastructure service providers.
2008	**Western Power** **Optimal treatment and application of capital contributions** Advice on the optimal regulatory treatment of capital contributions, taking into account the effect of alternative approaches on tariffs, regulatory asset values, and network connection by new customers.
2000-08	**TransGrid** **National electricity market and revenue cap reset** Regulatory advisor to TransGrid on a range of issues arising in the context of the national electricity market (NEM), including: the economics of transmission pricing and investment and its integration with the wholesale energy market, regulatory asset valuation, the cost of capital and TransGrid's 2004 revenue cap reset by the ACCC.
2007	**Johnson Winter & Slattery/Multinet** **Review of outsourced asset management contracts** Expert report developing a framework for assessing the prudence of outsourcing contracts in the context of the Gas Code, and evaluating the arrangements between Multinet and Alinta Asset Management by reference to that framework.
2007	**Ministerial Council on Energy** **Review of Chapter 5 of the National Electricity Rules** Advice on the development of a national framework for connection applications and capital contributions in the context of the National Electricity Rules.

2006-07	**Ministerial Council on Energy** **Demand side response and distributed generation incentives** Conducted a review of the MCE's proposed initial national electricity distribution network revenue and pricing rules to identify the implications for the efficient use of demand side response and distributed generation by electricity network owners and customers.
2006	**Ministerial Council on Energy** **Electricity network pricing rules** Advice on the framework for the development of the initial national electricity distribution network pricing rules, in the context of the transition to a single, national economic regulator.
2005-06	**Minister for Industry** **Expert Panel** Appointment by Hon Ian Macfarlane, Minister for Industry, Tourism and Resources, to an Expert Panel to advise the Ministerial Council on Energy on achieving harmonisation of the approach to regulation of electricity and gas transmission and distribution infrastructure.
2005-06	**Australian Energy Markets Commission** **Transmission pricing regime** Advice to the AEMC on its review of the transmission revenue and pricing rules as required by the new National Electricity Law.
1998-2006	**Essential Services Commission of Victoria** **Price cap reviews** Wide ranging advice to the Essential Services Commission (formerly the Office of the Regulator-General), on regulatory, financial and strategic issues arising in the context of five separate reviews of price controls/access arrangements applying in the electricity, gas distribution, ports, rail and water sectors in Victoria. This work encompassed advice on the development of the Commission's work program and public consultation strategy for each review, direct assistance with the drafting of papers for public consultation, the provision of internal papers and analysis on specific aspects of the review, drafting of decision documents, and acting as expert witness in hearings before the Appeal Panel and Victorian Supreme Court.
2004-05	**Ministerial Council of Energy** **Reform of the National Electricity Law** Retained in two separate advisory roles in relation to the reform of the institutions and legal framework underpinning the national energy markets. These roles include the appropriate specification of the objectives and rule making test for the national electricity market, and the development of a harmonised framework for distribution and retail regulation.
2004-05	**Johnson Winter Slattery, ETSA Utilities** **Price determination** Advice on a wide range of economic and financial issues in the context of ETSA Utilities' application for review of ESCOSA's determination of a five year electricity distribution price cap.
2004	**Deacons/ACCC** **Implementation of DORC valuation** Prepared a report on the implementation of a cost-based DORC valuation, for submission to the Australian Competition Tribunal in connection with proceedings on the appropriate gas transportation tariffs for the Moomba to Sydney gas pipeline.

2003-04   **Natural Gas Corporation, New Zealand**
                     Gas pipeline regulation
                     Advisor in relation to the inquiry by the Commerce Commission into the case
                     for formal economic regulation of gas pipelines. This role included assistance
                     with the drafting of submissions, the provision of expert reports, and the giving
                     of evidence before the Commerce Commission.

2001-03   **Rail Infrastructure Corporation**
                     Preparation of access undertaking
                     Advised on all economic aspects arising in the preparation of an access
                     undertaking for the New South Wales rail network. Issues arising included:
                     pricing principles under a `negotiate and arbitrate' framework, asset valuation,
                     efficient costs, capacity allocation and trading, and cost of capital.

2002   **Clayton Utz/TransGrid**
                     National Electricity Tribunal hearing
                     Retained as the principal economic expert in the appeal brought by Murraylink
                     Transmission Company of NEMMCO's decision that TransGrid's proposed
                     South Australia to New South Wales Electricity Interconnector was justified
                     under the national electricity code's 'regulatory test'.

2001-02   **SPI PowerNet**
                     Revenue cap reset
                     Advisor on all regulatory and economic aspects of SPI PowerNet's application
                     to the ACCC for review of its revenue cap applying from January 2003. This
                     included assistance on regulatory strategy, asset valuation in the context of
                     the transitional provisions of the national electricity code, drafting and editorial
                     support for the application document, and the conduct of a `devil's advocate'
                     review.

2002   **Corrs Chambers Westgarth/Ofgar**
                     Economic interpretation of the gas code
                     Provision of expert report and sworn testimony in the matter of Epic Energy v
                     Office of the Independent Gas Access Regulator, before the Supreme Court
                     of Western Australia, on the economic interpretation of certain phrases in the
                     natural gas pipelines access code.

Sworn Testimony, Transcribed Evidence[45]

2014

Expert evidence before a UNCITRAL arbitral tribunal on behalf of Maynilad Water Corporation Inc (MWCI), in the matter of MWCI v Metropolitan Waterworks and Sewerage System (MWSS)
Expert reports, sworn evidence, Sydney (by videolink to Manila), 31 August 2014

Expert evidence before the Australian Competition Tribunal on behalf of the ACCC, in the matter of AGL Energy v ACCC
Expert reports, sworn evidence, Sydney, 10-11 June 2014

2013

Expert evidence before the Supreme Court of Victoria on behalf of Maddingley Brown Coal in the matter of Maddingley Brown Coal v Environment Protection Agency of Victoria
Expert reports, sworn evidence, Melbourne, 12 August 2013

Expert evidence before the Federal Court on behalf of Modtech v GPT Management and Others
Expert reports, sworn evidence, Melbourne, 27 March 2013

2012

Expert evidence before the Supreme Court of Queensland on behalf of Origin Energy Electricity Ltd and Others v Queensland Competition Authority and Others
Expert reports, sworn evidence, Brisbane, 3 December 2012

2011

Expert evidence before the Federal Court on behalf of the Australian Turf Club and Australian Racing Board in the matter of Bruce McHugh v ATC and Others
Expert report, transcribed evidence, Sydney, 12 and 14 October 2011
Expert evidence in arbitration proceedings before J von Doussa, QC, on behalf of Santos in the matter of Santos and Others v Government of South Australia
Expert report, transcribed evidence, Adelaide, 13-15 September 2011
Expert evidence before a panel of arbitrators on behalf of UNELCO in the matter of UNELCO v Government of Vanuatu
Expert report, transcribed evidence, Melbourne, 23 March and 21 April 2011
Expert evidence before the Federal Court on behalf of ActewAGL in the matter of ActewAGL v Australian Energy Regulator
Expert report, sworn evidence, Sydney, 17 March 2011
Deposition Testimony in Re Payment Care Interchange and Merchant Discount Litigation, in the United States District Court for the Eastern District of New York
Deposition testimony, District of Colombia, 18 January 2011

2010

Expert evidence before the Federal Court in behalf of the Australia Competition and Consumer Commission in the matter of ACCC v Cement Australia and others
Expert report, sworn evidence, Brisbane, 19-21 October 2010
Expert evidence on behalf of Orion NZ, at the Commerce Commission's Conference on its Input Methodologies Emerging View Paper
Transcribed evidence, public hearings, Wellington, 24 February 2010
Deposition Testimony in *Re Payment Card Interchange and Merchant Discount Antitrust Litigation*, in the United States District Court for the Eastern District of New York
Deposition Testimony, District of Columbia, 18 February 2010

2009

Expert evidence before the Australian Competition Tribunal on behalf of Fortescue Metals Group Ltd, in the matter of Application for Review of Decision in Relation to

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[45]   Past ten years.

Declaration of Services Provided by the Robe, Hamersley, Mt Newman and Goldsworthy Railways
Expert report, sworn evidence, Melbourne, 12-13 October and 5-6 November 2009
Expert evidence on behalf of Orion NZ, at the Commerce Commission's Conference on its Input Methodologies Discussion Paper
Transcribed evidence, public hearings, Wellington, 16 September 2009
Expert evidence before the Federal Court on behalf of Fortescue Metals Group Ltd, in the matter of ASIC v Fortescue Metals Group and Andrew Forrest
Expert report, sworn evidence, Perth, 29 April–1 May 2009
Expert report and evidence in arbitration proceedings before Hon Michael McHugh, AC QC, and Roger Gyles, QC, between Origin Energy and AGL
Expert report, sworn evidence, Sydney, 19-24 March 2009

2008	**Expert evidence on behalf of Orion NZ, at the Commerce Commission's Conference on its Draft Decision on Authorisation for the Control of Natural Gas Pipeline Services**

Transcribed evidence, public hearings, Wellington, 21 February 2008

2007	**Expert report and evidence in arbitration proceedings before Sir Daryl Dawson between SteriCorp and Stericycle Inc.**

Expert report, sworn evidence, 11 July 2007

2006	**Expert report and evidence in arbitration proceedings before Sir Daryl Dawson and David Jackson, QC, between Santos and others, and AGL**

Expert report, sworn evidence, November 2006
Expert report and evidence before the Federal Court on behalf of Fortescue Metals Group in the matter of BHP Billiton v National Competition Council and Others
Expert report, sworn evidence, November 2006
Expert report and evidence in arbitration proceedings before Sir Daryl Dawson and David Jackson, QC, between Santos and Others, and Xstrata Queensland
Expert report, sworn evidence, September 2006
Expert report and evidence before the Copyright Tribunal on behalf of the Australian Hotels Association and others in the matter of PPCA v AHA and Others
Expert report, sworn evidence, May 2006
Expert report and evidence in arbitration proceedings before Hon Michael McHugh, AC QC, on the matter of AWB Limited v ABB Grain Limited
Expert report, sworn evidence, 24 May 2006
Expert report and evidence to Victorian Appeal Panel, in the matter of the appeal by United Energy Distribution of the Electricity Price Determination of the Essential Services Commission
Expert report, sworn evidence, 10 February 2006

2005	**Expert evidence on behalf of Orion NZ, at the Commerce Commission's Conference on its Notice of Intention to Declare Control of Unison Networks**

Transcribed evidence, public hearings, Wellington, 17 November 2005
Expert evidence on behalf of Orion NZ, at the Commerce Commission's Conference on Asset Valuation choice and the electricity industry disclosure regime
Transcribed evidence, public hearings, Wellington, 11 April 2005

2004	**Expert report and evidence to the Australian Competition Tribunal, in the matter of Virgin Blue Airlines v Sydney Airport Corporation**

Expert reports, sworn evidence, 19-20 October 2004
Expert evidence on behalf of Orion NZ, at the Commerce Commission's Conference on the ODV Handbook for electricity lines businesses
Transcribed evidence, public hearings, Wellington, 26 April 2004

A3. Model Examples

This appendix details the full calculation of the rewards, penalties, benefits and costs of the different scenarios set out in this report.

A3.1 Detailed modelling underpinning results in Table 1

Table 8 – Table 1: Scenario A – Permanent decrease in opex in year 2

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	90	90	90	90	90	90 p.a.
Actual (A_t)	100	90	90	90	90	90	90	90	90	90	90 p.a.
Underspend ($F_t - A_t = U_t$)	0	10	10	10	10	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	0	10	0	0	0	0	0	0	0	0	0 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			10	10	10	10	10				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					0	0	0	0	0		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						10	10	0	0	0	
Total cost of opex to customers	100	100	100	100	100	100	100	90	90	90	90 p.a.
Benefits to NSP ($Ft - At + Ct$)	0	10	10	10	10	10	10	0	0	0	0
Benefits to consumers ($F1 - (Ft + Ct)$)	0	0	0	0	0	0	0	10	10	10	177
Discounted benefits to NSP***	0.0	9.4	8.9	8.4	7.9	7.5	7.0	0.0	0.0	0.0	0.0
Discounted benefits to consumers***	0	0	0	0	0	0	0	6.7	6.3	5.9	98.6

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 9 – Table 1: Scenario B – Permanent decrease in opex in year 4

	Period 1					Period 2					Future
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	
Forecast (F_t)	100	100	100	100	100	90	90	90	90	90	90 p.a.
Actual (A_t)	100	100	100	90	90	90	90	90	90	90	90 p.a.
Underspend ($F_t - A_t = U_t$)	0	0	0	10	10	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	0	0	0	10	0	0	0	0	0	0	0 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					10	10	10	10	10		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						10	10	10	10	0	
Total cost of opex to customers	100	100	100	100	100	100	100	100	100	90	90 p.a.
Benefits to NSP ($Ft - At + Ct$)	0	0	0	10	10	10	10	10	10	0	0
Benefits to consumers ($F1 - (Ft + Ct)$)	0	0	0	0	0	0	0	0	0	10	177
Discounted benefits to NSP***	0.0	0.0	0.0	8.4	7.9	7.5	7.0	6.7	6.3	0.0	0.0
Discounted benefits to consumers***	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	98.6

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 10 – Table 1: Scenario C – Permanent increase in opex in year 2

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	110	110	110	110	110	110 p.a.
Actual (A_t)	100	110	110	110	110	110	110	110	110	110	110 p.a.
Underspend ($F_t - A_t = U_t$)	0	-10	-10	-10	-10	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	0	-10	0	0	0	0	0	0	0	0	0 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			-10	-10	-10	-10	-10				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					0	0	0	0	0		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						-10	-10	0	0	0	
Total cost of opex to customers	100	100	100	100	100	100	100	110	110	110	110 p.a.
Benefits to NSP ($Ft - At + Ct$)	0	-10	-10	-10	-10	-10	-10	0	0	0	0
Benefits to consumers ($F1 - (Ft + Ct)$)	0	0	0	0	0	0	0	-10	-10	-10	-177
Discounted benefits to NSP***	0.0	-9.4	-8.9	-8.4	-7.9	-7.5	-7.0	0.0	0.0	0.0	0.0
Discounted benefits to consumers***	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-6.7	-6.3	-5.9	-98.6

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 11 – Table 1: Scenario D – One off decrease in opex in year 3

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	100	100	100	100	100	100 p.a.
Actual (A_t)	100	100	90	100	100	100	100	100	100	100	100 p.a.
Underspend ($F_t - A_t = U_t$)	0	0	10	0	0	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	0	0	10	-10	0	0	0	0	0	0	0 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				10	10	10	10	10			
Carryover (I_4)					-10	-10	-10	-10	-10		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						0	0	0	-10	0	
Total cost of opex to customers	100	100	100	100	100	100	100	100	90	100	100 p.a.
Benefits to NSP ($F_t - A_t + C_t$)	0	0	10	0	0	0	0	0	-10	0	0
Benefits to consumers ($F_1 - (F_t + C_t)$)	0	0	0	0	0	0	0	0	10	0	0
Discounted benefits to NSP***	0.0	0.0	8.9	0.0	0.0	0.0	0.0	0.0	-6.3	0.0	0.0
Discounted benefits to consumers***	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.3	0.0	0.0

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

A3.2 Detailed modelling underpinning results in Table 2

Table 12 – Table 2: Scenario A – One off increase in year 4

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	120	120	120	120	120	100 p.a.
Actual (A_t)	100	100	100	120	100	100	100	100	100	100	100 p.a.
Underspend ($F_t - A_t = U_t$)	0	0	0	-20	0	20	20	20	20	20	20 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	0	0	0	-20	20	20	0	0	0	0	4.5 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					-20	-20	-20	-20	-20		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						-20	-20	-20	-20	0	
Total cost of opex to customers	100	100	100	100	100	100	100	100	100	120	100 p.a.
Benefits to NSP ($Ft - At + Ct$)	0	0	0	-20	0	0	0	0	0	20	0
Benefits to consumers ($F1 - (Ft + Ct)$)	0	0	0	0	0	0	0	0	0	-20	0
Discounted benefits to NSP***	0.0	0.0	0.0	-16.8	0.0	0.0	0.0	0.0	0.0	11.8	0.0
Discounted benefits to consumers***	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-11.8	0.0

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 13 – Table 2: Scenario B1 – Opex savings in the early years

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	85	85	85	85	85	85 p.a.
Actual (A_t)	95	90	85	85	85	85	85	85	85	85	85 p.a.
Underspend ($F_t - A_t = U_t$)	5	10	15	15	15	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	5	5	5	0	0	0	0	0	0	0	0 p.a.
Carryover (I_1)		5	5	5	5	5					
Carryover (I_2)			5	5	5	5	5				
Carryover (I_3)				5	5	5	5	5			
Carryover (I_4)					0	0	0	0	0		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						15	10	5	0	0	
Total cost of opex to customers	100	100	100	100	100	100	95	90	85	85	85 p.a.
Benefits to NSP ($Ft - At + Ct$)	5	10	15	15	15	15	10	5	0	0	0
Benefits to consumers ($F1 - (Ft + Ct)$)	0	0	0	0	0	0	5	10	15	15	265
Discounted benefits to NSP***	5.0	9.4	13.3	12.6	11.9	11.2	7.0	3.3	0.0	0.0	0.0
Discounted benefits to consumers***	0.0	0.0	0.0	0.0	0.0	0.0	3.5	6.7	9.4	8.9	148.0

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 14 – Table 2: Scenario B2 – Opex savings in the early years and reversed in year 4

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	100	100	100	100	100	100 p.a.
Actual (A_t)	95	90	85	100	100	100	100	100	100	100	100 p.a.
Underspend ($F_t - A_t = U_t$)	5	10	15	0	0	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	5	5	5	-15	0	0	0	0	0	0	0 p.a.
Carryover (I_1)		5	5	5	5	5					
Carryover (I_2)			5	5	5	5	5				
Carryover (I_3)				5	5	5	5	5			
Carryover (I_4)					-15	-15	-15	-15	-15		
Carryover (I_5)							0	0	0	0	0
Carryover amount (C_t)							0	-5	-10	-15	0
Total cost of opex to customers	100	100	100	100	100	100	95	90	85	100	100 p.a.
Benefits to NSP ($F_t - A_t + C_t$)	5	10	15	0	0	0	-5	-10	-15	0	0
Benefits to consumers ($F_1 - (F_t + C_t)$)	0	0	0	0	0	0	5	10	15	0	0
Discounted benefits to NSP***	5.0	9.4	13.3	0.0	0.0	0.0	-3.5	-6.7	-9.4	0.0	0.0
Discounted benefits to consumers***	0.0	0.0	0.0	0.0	0.0	0.0	3.5	6.7	9.4	0.0	0.0

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 15 – Table 2: Scenario B3 – Opex savings in the early years and reversed in year 4 and opex savings 'rediscovered' in year 5

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	100	100	100	100	100	85 p.a.
Actual (A_t)	95	90	85	100	85	85	85	85	85	85	85 p.a.
Underspend ($F_t - A_t = U_t$)	5	10	15	0	15	15	15	15	15	15	15 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	5	5	5	-15	15	15	0	0	0	0	3.4 p.a.
Carryover (I_1)		5	5	5	5	5					
Carryover (I_2)			5	5	5	5	5				
Carryover (I_3)				5	5	5	5	5			
Carryover (I_4)					-15	-15	-15	-15	-15		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						0	-5	-10	-15	0	
Total cost of opex to customers	100	100	100	100	100	100	95	90	85	100	85 p.a.
Benefits to NSP ($F_t - A_t + C_t$)	5	10	15	0	15	15	10	5	0	15	0
Benefits to consumers ($F_1 - (F_t + C_t)$)	0	0	0	0	0	0	5	10	15	0	265
Discounted benefits to NSP***	5.0	9.4	13.3	0.0	11.9	11.2	7.0	3.3	0.0	8.9	0.0
Discounted benefits to consumers***	0.0	0.0	0.0	0.0	0.0	0.0	3.5	6.7	9.4	0.0	148.0

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 16 – Table 2: Scenario C – DNSP brings forward opex from year 5 to year 4

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	120	120	120	120	120	100 p.a.
Actual (A_t)	100	100	100	120	80	100	100	100	100	100	100 p.a.
Underspend ($F_t - A_t = U_t$)	0	0	0	-20	20	20	20	20	20	20	20 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	0	0	0	-20	40	20	0	0	0	0	4.5 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					-20	-20	-20	-20	-20		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						-20	-20	-20	-20	0	
Total cost of opex to customers	100	100	100	100	100	100	100	100	100	120	100 p.a.
Benefits to NSP ($Ft - At + Ct$)	0	0	0	-20	20	0	0	0	0	20	-20
Benefits to consumers ($F1 - (Ft + Ct)$)	0	0	0	0	0	0	0	0	0	-20	20
Discounted benefits to NSP***	0.0	0.0	0.0	-16.8	15.8	0.0	0.0	0.0	0.0	11.8	-11.2
Discounted benefits to consumers***	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-11.8	11.2

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

A3.3 Detailed modelling underpinning results in Table 5

Table 17 – Table 5: Scenario A – DNSP incurs 166.7 in additional year 1 opex to achieve a 10 reduction in recurring opex

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	90	90	90	90	90	90 p.a.
Actual (A_t)	267	90	90	90	90	90	90	90	90	90	90 p.a.
Underspend ($F_t − A_t = U_t$)	-167	10	10	10	10	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t − U_{t-1}$)	-167	177	0	0	0	0	0	0	0	0	0 p.a.
Carryover (I_1)		-167	-167	-167	-167	-167					
Carryover (I_2)			177	177	177	177	177				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					0	0	0	0	0		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						10	177	0	0	0	
Total cost of opex to customers	100	100	100	100	100	100	267	90	90	90	90 p.a.
Benefits to NSP ($Ft − At + Ct$)	-167	10	10	10	10	10	177	0	0	0	0
Benefits to consumers ($F1 − (Ft + Ct)$)	0	0	0	0	0	0	-167	10	10	10	177
Discounted benefits to NSP***	-166.7	9.4	8.9	8.4	7.9	7.5	124.5	0.0	0.0	0.0	0.0
Discounted benefits to consumers***	0.0	0.0	0.0	0.0	0.0	0.0	-117.5	6.7	6.3	5.9	98.6

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 18 – Table 5: Scenario B – DNSP incurs 150.0 in additional year 1 opex to achieve a 10 reduction in recurring opex

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	90	90	90	90	90	90 p.a.
Actual (A_t)	250	90	90	90	90	90	90	90	90	90	90 p.a.
Underspend ($F_t - A_t = U_t$)	-150	10	10	10	10	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	-150	160	0	0	0	0	0	0	0	0	0 p.a.
Carryover (I_1)		-150	-150	-150	-150	-150					
Carryover (I_2)			160	160	160	160	160				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					0	0	0	0	0		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						10	160	0	0	0	
Total cost of opex to customers	100	100	100	100	100	100	250	90	90	90	90 p.a.
Benefits to NSP ($Ft - At + Ct$)	-150	10	10	10	10	10	160	0	0	0	0
Benefits to consumers ($F1 - (Ft + Ct)$)	0	0	0	0	0	0	-150	10	10	10	177
Discounted benefits to NSP***	-150.0	9.4	8.9	8.4	7.9	7.5	112.8	0.0	0.0	0.0	0.0
Discounted benefits to consumers***	0.0	0.0	0.0	0.0	0.0	0.0	-105.7	6.7	6.3	5.9	98.6

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 19 – Table 5: Scenario C – DNSP incurs 200.0 in additional year 1 opex to achieve a 10 reduction in recurring opex

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	90	90	90	90	90	90 p.a.
Actual (A_t)	300	90	90	90	90	90	90	90	90	90	90 p.a.
Underspend ($F_t - A_t = U_t$)	-200	10	10	10	10	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	-200	210	0	0	0	0	0	0	0	0	0 p.a.
Carryover (I_1)		-200	-200	-200	-200	-200					
Carryover (I_2)			210	210	210	210	210				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					0	0	0	0	0		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						10	210	0	0	0	
Total cost of opex to customers	100	100	100	100	100	100	300	90	90	90	90 p.a.
Benefits to NSP ($Ft - At + Ct$)	-200	10	10	10	10	10	210	0	0	0	0
Benefits to consumers ($F1 - (Ft + Ct)$)	0	0	0	0	0	0	-200	10	10	10	177
Discounted benefits to NSP***	-200.0	9.4	8.9	8.4	7.9	7.5	148.0	0.0	0.0	0.0	0.0
Discounted benefits to consumers***	0.0	0.0	0.0	0.0	0.0	0.0	-141.0	6.7	6.3	5.9	98.6

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

A3.4 Detailed modelling underpinning results in Table 7

Table 20 – Table 7: Scenario A – 0% achievement of benchmark level of expenditure

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	90	90	90	90	90	90	90	90	90	90	90 p.a.
Actual (A_t)	100	100	100	100	100	100	100	100	100	100	100 p.a.
Underspend ($F_t - A_t = U_t$)	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	-10	0	0	0	0	-10	0	0	0	0	-2.2 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					0	0	0	0	0		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						00	0	0	0	0	
Total cost of opex to customers	90	90	90	90	90	90	90	90	90	90	90 p.a.
Benefits to NSP ($Ft - At + Ct$)	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-187
Benefits to consumers ($F1 - (Ft + Ct)$)	10	10	10	10	10	20	10	10	10	10	187
Discounted benefits to NSP***	-10.0	-9.4	-8.9	-8.4	-7.9	-7.5	-7.0	-6.7	-6.3	-5.9	-98.6
Discounted benefits to consumers***	10.0	9.4	8.9	8.4	7.9	7.5	7.0	6.7	6.3	5.9	98.6

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 21 – Table 7: Scenario B – 50% achievement of benchmark level of expenditure

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	90	90	90	90	90	90	90	90	90	90	90 p.a.
Actual (A_t)	95	95	95	95	95	95	95	95	95	95	95 p.a.
Underspend ($F_t - A_t = U_t$)	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	-5	0	0	0	0	-5	0	0	0	0	-1.1 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					0	0	0	0	0		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						0	0	0	0	0	0
Total cost of opex to customers	90	90	90	90	90	90	90	90	90	90	90 p.a.
Benefits to NSP ($Ft - At + Ct$)	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-93
Benefits to consumers ($F1 - (Ft + Ct)$)	10	10	10	10	10	10	10	10	10	10	187
Discounted benefits to NSP***	-5.0	-4.7	-4.4	-4.2	-4.0	-3.7	-3.5	-3.3	-3.1	-3.0	-49.3
Discounted benefits to consumers***	10.0	9.4	8.9	8.4	7.9	7.5	7.0	6.7	6.3	5.9	89.6

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 22 – Table 7: Scenario C – 100% achievement of benchmark level of expenditure

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	90	90	90	90	90	90	90	90	90	90	90 p.a.
Actual (A_t)	90	90	90	90	90	90	90	90	90	90	90 p.a.
Underspend ($F_t - A_t = U_t$)	0	0	0	0	0	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	0	0	0	0	0	0	0	0	0	0	0 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					0	0	0	0	0		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						0	0	0	0	0	0.0
Total cost of opex to customers	90	90	90	90	90	90	90	90	90	90	90 p.a.
Benefits to NSP ($Ft - At + Ct$)	0	0	0	0	0	0	0	0	0	0	0
Benefits to consumers ($F1 - (Ft + Ct)$)	10	10	10	10	10	10	10	10	10	10	187
Discounted benefits to NSP***	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Discounted benefits to consumers***	10.0	9.4	8.9	8.4	7.9	7.5	7.0	6.7	6.3	5.9	98.6

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 23 – Table 7: Scenario D – 150% achievement of benchmark level of expenditure

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	90	90	90	90	90	85	85	85	85	85	85 p.a.
Actual (A_t)	85	85	85	85	85	85	85	85	85	85	85 p.a.
Underspend ($F_t - A_t = U_t$)	5	5	5	5	5	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	5	0	0	0	0	0	0	0	0	0	0 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					0	0	0	0	0		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						0	0	0	0	0	0
Total cost of opex to customers	90	90	90	90	90	85	85	85	85	85	85 p.a.
Benefits to NSP ($Ft - At + Ct$)	5	5	5	5	5	0	0	0	0	0	0
Benefits to consumers ($F1 - (Ft + Ct)$)	10	10	10	10	10	10	15	15	15	15	280
Discounted benefits to NSP***	5.0	4.7	4.4	4.2	4.0	0	0.0	0.0	0.0	0.0	0.0
Discounted benefits to consumers***	10.0	9.4	8.9	8.4	7.9	7.5	10.6	10.0	9.4	8.9	148.0

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.

Table 24 – Table 7: Scenario E – 200% achievement of benchmark level of expenditure

	Period 1					Period 2					Future
Year	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	90	90	90	90	90	80	80	80	80	80	80 p.a.
Actual (A_t)	80	80	80	80	80	80	80	80	80	80	80 p.a.
Underspend ($F_t - A_t = U_t$)	10	10	10	10	10	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	10	0	0	0	0	0	0	0	0	0	0 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					0	0	0	0	0		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						10	0	0	0	0	0
Total cost of opex to customers	90	90	90	90	90	80	80	80	80	80	80 p.a.
Benefits to NSP ($F_t - A_t + C_t$)	10	10	10	10	10	0	0	0	0	0	0
Benefits to consumers ($F_1 - (F_t + C_t)$)	10	10	10	10	10	20	20	20	20	20	373
Discounted benefits to NSP***	10.0	9.4	8.9	8.4	7.9	0	0.0	0.0	0.0	0.0	0.0
Discounted benefits to consumers***	10.0	9.4	8.9	8.4	7.9	14.9	14.1	13.3	12.5	11.8	197.3

Note: All present value calculation in year 1 dollars, and adopts a 6% real discount rate.
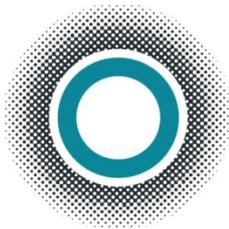
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