EXPENDITURE INCENTIVES FACED BY NETWORK SERVICE PROVIDERS

AUSTRALIAN ENERGY MARKET COMMISSION

25 MAY 2018

FINAL REPORT

Prepared by:

Cambridge Economic Policy Associates Pty Ltd

CONTENTS

Disclaimer

ABBREVIATIONS

Acronym	Description
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
BEE	Benchmark Efficient Entity
Capex	Capital expenditure
CEPA	Cambridge Economic Policy Associates
CESS	Capital Expenditure Sharing Scheme
DER	Distributed energy resources
DM	Demand management
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DPCR	Distribution price control review
EBSS	Efficiency Benefit Sharing Scheme
IQI	Information Quality Incentive
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	Net present value
NSP	Network service provider
NY REV	New York state ‘Reforming the Energy Vision’
Opex	Operating expenditure
PSC	New York Public Services Commission
PTRM	Post-tax revenue model
PV	Present value
RAB	Regulatory asset base
RCV	Regulatory capital value
RFM	Roll forward model
RIN	Regulatory Information Notice
RIT	Regulatory Investment Test
SAPN	South Australia Power Networks
STPIS	Service Target Performance Incentive Scheme

Acronym	Description
Totex	Total expenditure
WACC	Weighted average cost of capital

EXECUTIVE SUMMARY

The Australian Energy Market Commission (AEMC) has commissioned Cambridge Economic Policy Associates (CEPA) to assess the regulatory financial incentives, and other non-regulatory incentives, currently faced by electricity network service providers (NSPs) in the National Electricity Market (NEM).

In particular, the AEMC is interested in whether there is evidence to support persistent stakeholder concerns that the current incentive arrangements create (or fail to correct for) a capital expenditure (capex) bias, where NSPs may be inappropriately choosing capex solutions over operating expenditure (opex) solutions. Such a bias may also appear as a preference for in-house (including the use of ring-fenced affiliates) rather than outsourced solutions. If a bias does exist, it is now of greater concern given the increasing availability of alternatives to 'traditional' (NSP-initiated, capex-based) approaches to delivering regulated network services, provided either by the NSP or third parties.[1]

In this report we seek to:

- Establish whether the current regulatory framework in the NEM creates a financial incentive for NSPs to prefer capex to opex (or vice-versa).
- Identify any other qualitative reasons that might create an incentive to favour a particular approach.

Regulatory incentive mechanisms

A key objective of the NEM regulatory framework, and recent rule changes, is to incentivise genuine outperformance and innovation to mimic the operation of a competitive market. At the time of the framework's development, the efficient, safe, and reliable conveyance of electricity primarily required capital investment in long-lived assets (wires, poles, etc.), and the design of the framework reflected this.

The framework is continually evolving, and a suite of incentive mechanisms is now in place to meet the requirements of various rule changes. However, the combination of these mechanisms, developed at different times over the last 10 to 15 years, may have resulted in unintended incentives on NSPs, or the NSPs misinterpreting and responding to the incentives incorrectly.

The regulatory framework includes incentives that influence how NSPs prepare their regulatory proposals (pre-allowance determination incentives) and incentives that influence their decision-making process once the determination is complete (post-allowance

[1] It is important to consider that the potential substitution between opex and capex may not be limited to assets with shorter lives or deferrals. This could include longer term third-party contracts, or not yet identified longer term opex solutions that may become more apparent with technological progress.

determination incentives). Although we describe these incentives separately, NSPs would consider any post-allowance incentives when developing their regulatory proposals.

The two key pre-allowance determination incentives are:

- **The approach to assessing expenditure proposals.** There is a general financial incentive on NSPs to gain high allowances to increase their scope for outperformance and cover the risk of outturn costs being higher than expected. The Australian Energy Regulator (AER) typically relies on revealed costs to set a base opex year to roll forward, with benchmarking employed to assess the efficiency of the base-year.[2] This process is repeated at each determination. Capex requires an assessment of a greater range of 'bespoke' projects. As these are one-off assessments, the process is 'done-and-dusted' in a single determination.
- **The rate of return allowance.** The AER provides detailed guidelines on how it will determine the allowed return. The NSPs therefore have reasonable visibility of what the allowed return will be and therefore their scope for out-/ under-performance on financing costs. This may influence decisions on what capex projects to include in the regulatory proposal.

There are three explicit financial incentive mechanisms that are intended to influence the NSPs during the regulatory control period (i.e. post-allowance determination incentives):

- **The Efficiency Benefit Sharing Scheme (EBSS).** This was designed to equalise the NSPs' incentives throughout the regulatory control period to achieve opex efficiencies. The EBSS was introduced for use in determinations from 2008, with minor updates made in 2013.
- **The Capital Expenditure Sharing Scheme (CESS).** This was designed to equalise the NSPs' incentives throughout the regulatory control period to achieve capex efficiencies. It was also intended to help balance the incentives between capex and opex. The CESS was introduced for use in determinations from 2013.
- **The Demand Management Incentive Scheme (DMIS).** This was designed to encourage NSPs to appropriately consider demand side management solutions as an alternative to non-network solutions. The DMIS was introduced for use in determinations from April 2018 (including use in existing determinations).

The complete package of incentive mechanisms has not been in place for very long. Therefore, both the NSPs and the AER are still learning how the mechanisms will work in practice; and the NSPs' responses will evolve over time. The feedback received during a workshop with industry stakeholders on the 23rd of April 2018 indicated that NSPs are responding to the new incentive regime that is now in place following the introduction of the CESS and the DMIS, but it will take time for them to adapt.

[2] The NER also require the AER to consider the substitutability between opex and capex.

Observing a capex bias

In practice, observing a capex bias is difficult, as there is a myriad of factors that influence NSPs' decisions, both when they (1) develop their regulatory proposals and (2) respond to their allowances and operating conditions. The latter includes changes in capitalisation policies, demand being higher or lower than forecast, and new and amended incentive mechanisms. In addition, there is a lack of a counterfactual (i.e., a bias-free scenario) to compare with. This limits the usefulness of analysing historical data.

While limited conclusions can be drawn from historical comparisons, we have used available data to assess the NSPs' performance during their most recently completed regulatory determination period. This covers a period when the EBSS was in place, but not the CESS or DMIS.

We found that the distribution NSPs (DNSPs) generally outperformed[3] their capex allowances (only three under-performed), but only four outperformed their opex allowances. However, forecast demand did not eventuate, and a proportion of augmentation capex was not required. Therefore, the observed capex outperformance is likely to be higher than under a counterfactual where demand did eventuate as forecast. All the transmission NSPs (TNSPs) outperformed both opex and capex. However, their capex outperformance was significantly higher.

The observed capex outperformance could indicate a greater level of information asymmetry between the NSPs and the AER, compared to opex. Alternatively, the lower, or lack of, outperformance against opex could indicate a lower incentive to make efficiency gains compared to capex. However, given the lack of a counterfactual and our inability to disentangle the different factors influencing the NSPs' spending, based on the historical data we cannot conclude whether there is a capex bias or not.

Modelling the financial incentives

As the findings from the available data are limited, we have modelled the financial incentives under the regulatory framework. Our model uses the underlying assumptions and mechanisms from the AER's post-tax revenue, roll forward, EBSS and CESS models. While we did not explicitly include the DMIS in our modelling due to the project-specific nature of the incentive, we did consider how it might affect the outcomes of the modelling in broad terms.

We have considered the financial modelling based on two broad alternative assumptions:

1) The NSP faces a choice between two equally efficient opex or capex solutions that deliver the same outcomes. In this case, we assume the NSP is responding to a change in output requirements and it can implement an opex or capex solution. This solution has a finite duration. At the end of the solution's useful life, we assume the opex

[3] In other words, spent less than their allowance.

allowance is adjusted back to the original opex allowance, based on the original level of outputs.

2) The AER's approach, where the EBSS and CESS are used to provide time-independent incentives on opex and capex. If opex efficiencies (or inefficiencies) occur in perpetuity and the WACC is 6%, then the incentive strength on opex and capex will be equal. If the opex efficiencies (or inefficiencies) do not occur in perpetuity, the EBSS will reverse any original reward/penalty such that the NSPs should only gain/bear the time value of money.

To model these assumptions, we compare present value (PV) equivalent opex or capex solutions. The solutions are assumed to last for the same period and deliver the same levels of reliability and safety. [4] That is, the opex solution is in place for the length of the alternative capex solution's useful asset life. However, under the second broad assumption, we assume that opex continues after the end of the solution life.

We assess the financial incentive strength by dividing the net present value (NPV) outcome for a capex solution by the NPV outcome for the PV equivalent opex 'solution' (the 'NPV ratio').[5]

The findings from this exercise were:

- Under the first broad assumption, our modelling indicates that there is a positive financial incentive for NSPs to prefer capex to opex, if such a trade-off is possible. This incentive diminishes as the assumed life of the asset – and therefore the duration of the opex solution – increases. However, the incentive remains positive for the more common network asset lives up to 40 years. After the asset lives increase beyond 40 years a smaller (but increasing) financial incentive is created to prefer opex.
- Under the second broad assumption, our modelling indicates that achieving capex efficiencies may provide a slightly higher financial return than achieving opex efficiencies (i.e., an incentive to prefer opex rather than capex). This is driven by the different tax treatment of opex and capex.
- The DMIS increases the incentive to undertake demand management solutions (potentially either opex or capex), but only for certain projects.

[4] We have not included the Service Target Performance Incentive Scheme (STPIS) in our modelling. As we assume that the different options modelled (capex or opex) deliver the same level of reliability, the STPIS would not impact on the results. In practice, if reliability impacts differ between the options that an NSP is considering, then the NSP would need to consider the additional impact of STPIS penalties/ payments.

[5] An NPV ratio of 0.5 means that the NSP's financial benefit from underspending on opex will be twice as great as for a capex solution. Alternatively, a 2.0 ratio means that underspending on a capex solution delivers a financial benefit that is twice as great as for an alternative opex solution. Therefore, when the NPV ratio is less than one, a reduction in opex rather than capex will increase investors' overall returns.

Other incentives

In addition to the regulatory incentive schemes outlined above, we identified other factors that may influence NSP decision making. This analysis was drawn from material including regulatory reports, company submissions, financial analyst reports and credit rating agency reports. The potential factors we identified include:

- An investor preference for NSPs to 'grow the RAB', to increase overall earnings and maintain long-term, stable shareholder returns.
- Risk aversion, resulting in a preference for deploying more commonly used capex approaches instead of adopting alternative solutions. This could be due to concerns about the ability to maintain service standards (avoid penalties) or uncertainty around the ongoing expected cost of alternative solutions.
- Reputational incentives. This could include avoiding solutions which may not be 'tried and tested', or concerns about public and investor perceptions if the company appears more inefficient than its peers due to its approach.
- Existing cultural biases that favour a 'poles and wires' solution over alternative solutions, resulting from an NSP's history, skill base and ownership/organisational structure.

Key findings

Our analysis indicates that:

- **The financial incentives for NSPs vary depending on individual circumstances, but they are not equal between opex and capex.** If we assume that an NSP is considering whether to undertake equally efficient opex or capex solutions, which deliver the same outcomes, our modelling indicates that the NSP will have a financial incentive to prefer capex over opex. In contrast, if we assume the opex solution lasts into perpetuity (rather than for the same length of time as the CESS) then there is a slight financial incentive for the NSPs to underspend on capex rather than opex.
- **The financial incentives are asymmetric if the NSPs' WACC is different from the allowed rate of return.** An NSP's financial incentive to undertake capex rather than opex is stronger when it can outperform the allowed rate of return. In addition, our analysis indicates that when an NSP's actual WACC is lower than the allowed rate of return, its financial incentive to undertake capex is stronger than its financial incentive to undertake opex if the situation was reversed.[6] In other words, the financial incentives when out-/ under-performing the allowed rate of return are asymmetric, and the asymmetry favours capex.

[6] Assuming that the NSP out-/under-performs the allowed rate of return by the same number of basis points.

- **There is no simple fix to the EBSS and CESS to equalise the incentives on opex and capex.** The basis of the CESS *ex ante* sharing factor depends on an assumed in perpetuity opex saving and a fixed (pre-tax) discount rate of 6%. Neither of these assumptions are likely to hold in practice, particularly if the actual cost of capital is different from the allowed cost of capital.[7]
- **The DMIS provides an incentive, for specific projects, to favour demand management over 'network solutions'.** The DMIS can, depending on the specific requirements of the project, more than fully offset the financial bias in the underlying framework of the EBSS and CESS.
- **The AER assess capex differently from opex.** The AER typically uses revealed costs to set a base opex level, with benchmarking used to assess the efficiency of the base expenditure level. The base opex is then trended forward using estimates of outputs, productivity, and input prices. In contrast, a more bespoke assessment is used for capex as investment needs vary over time. NSPs may seek to avoid opex solutions to avoid appearing inefficient in the benchmarking. This creates both a financial incentive, as opex is more likely to be reduced than capex, and a reputational incentive.
- **The combined effects of the incentive mechanisms are complex.** We have found it difficult to model the interaction between all the financial incentives. We have predominately focused on modelling the CESS and EBSS, as it is not clear yet how the DMIS will work in practice with these other incentive mechanisms. The outcomes from the modelling depended on the assumptions we made. Each NSP will need to assess how the mechanisms apply to them and therefore how they should respond. Greater complexity increases the likelihood that NSPs will respond in unintended ways. We note that the AER has previously observed that incentives under the EBSS change if allowances are set exogenously (i.e., when a revealed cost approach in perpetuity is not used).[8] The AER did not apply an EBSS in the 2015 decisions for ACT and NSW, after benchmarking analysis was used to determine their allowed revenue; this suggests a level of uncertainty around how the incentive mechanisms will interact with the cost assessment framework in future.
- **'Network' capex is more likely to provide the NSPs with stable cash flows compared to more innovative opex solutions.** Aside from the DMIS, there is no explicit working capital allowance (margin on opex) for changes in the operational leverage of individual NSPs and any associated changes in their risk profile from adopting opex solutions with greater levels of uncertainty around future costs. Therefore, risk averse

[7] Ofgem's and Ofwat's solution to this issue was to simplify the incentive mechanism by treating opex and capex together and capitalising a proportion of the total. This approach does lead to changes in other part of the regulatory framework (such as the treatment of depreciation and the need for financeability assessments).
[8] AER (2013a).

investors/ management may seek to avoid opex projects with greater uncertainty around future costs and outputs.

- **Anecdotal evidence indicates that investors are interested in stable long-term cash flows.** Therefore, any shift away from maintaining or growing the regulatory asset base (RAB) will reduce the magnitude of future profits, and therefore future dividend growth. This preference appears to disregard the theory that investors should be indifferent to an opex or capex solution if the allowed rate of return is set equal to their actual cost of capital, and that the size of equity and debt will reduce alongside the RAB.

More generally, we note that the current regulatory framework was developed with a RAB based approach at its heart. This incentivised capex, as no return (a margin) was provided on opex to cover working capital. The provisions of the current regulatory framework have in turn attracted a certain type of investor. This may create a self-reinforcing capex bias.

Overall, the analysis we have undertaken highlights the complexity of the interaction between the incentive mechanisms and how the perception of the incentives can change depending on the assumptions made. While we are unable to prove the presence of a systematic capex bias, we can conclude that the incentives provided by the current regulatory framework are not balanced across capex and opex. NSPs need to consider carefully the interaction between the incentive mechanisms, and this may affect the accurate identification of the option that will deliver the most efficient, reliable, and safe solution for consumers. This may be appropriate in the short term. For example, we note that the DMIS is intended to encourage a broader uptake of demand management solutions.[9] However, in the longer term, we consider that options to simplify and streamline the incentive framework should be investigated, particularly as the availability and feasibility of alternative options to traditional network solutions is anticipated to increase.

[9] AER (2017c).

1. INTRODUCTION

The AEMC is concerned that if a capital expenditure (capex) bias exists, NSPs may inappropriately choose 'traditional' capex approaches over more efficient alternative approaches that instead utilise operating expenditure (opex). As it is expected that the availability of alternative solutions will increase in the future, particularly for distributed energy resources, the materiality of any existing capex bias would likely increase.

A capex bias could result from a number of different factors, including: financial incentives embedded within the framework; information asymmetries, and how the AER approaches the assessment of opex and capex; and aspects of NSPs' corporate culture that may favour particular approaches.

In this report we seek to:

- Establish whether the current regulatory framework in the NEM creates a financial incentive for NSPs to prefer capex to opex (or vice-versa).
- Identify any other qualitative reasons that might create an incentive to favour a particular approach.

The Australian Energy Market Commission (AEMC) has commissioned Cambridge Economic Policy Associates (CEPA) to provide modelling and analysis on the regulatory financial incentives - and other non-regulatory incentives - that electricity network service providers (NSPs) in the National Electricity Market (NEM) face under the current National Electricity Rules (NER).[10] The incentive-based, building-blocks regulatory framework is set out in Chapters 6 and 6A of the NER.

In particular, the AEMC is interested in whether there is evidence to support persistent stakeholder concerns that the current incentive arrangements create (or fail to correct for) a capital expenditure (capex) bias. That is, where NSPs may be biased towards inappropriately choosing capex solutions over operating expenditure (opex) solutions. Such a bias may also appear as a preference for in-house (including the use of ring-fenced affiliates) rather than outsourced solutions. If a bias does exist, it is now of greater concern given the increasing availability of alternatives to 'traditional' (NSP-initiated, capex-based) approaches to delivering regulated network services, provided either by the NSP or third parties.[11]

As part of this project, the AEMC hosted a stakeholder workshop on the 23rd of April 2018. At the workshop we presented our draft report findings and sought stakeholders' views on the incentives in the existing framework. In addition to responses during the workshop, stakeholders were also given the opportunity to engage in a follow-up discussion or provide a written submission.

[10] This work forms part of the AEMC's 2018 'Electricity network economic regulatory framework review'.

[11] It is important to consider that the potential substitution between opex and capex may not be limited to shorter lived assets or deferrals. This could include longer term third-party contracts, or not yet identified longer term opex solutions that may become more apparent with technological progress.

1.1. Overview of the current regulatory framework

The building blocks regulatory framework prescribed by the NER was developed to address the natural monopoly characteristics of energy networks. At the time of the framework's development, the efficient, safe, and reliable conveyance of electricity primarily required capital investment in long-lived assets (wires, poles, etc.). Customers would benefit from these investments over the life of the assets, which creates a mismatch between when the costs are incurred and when the benefits accrue. As such, the regulatory framework was primarily focused on how to address this mismatch.

At the time, opex was primarily seen as costs that had to be incurred to enable the operation of the network. With the emergence of distributed energy resources (DER), improved real-time information and new innovations, it is expected that there will be increasingly effective alternatives to traditional capex approaches. Subject to the AER's ring-fencing guidelines,[12] to the extent that NSPs use DER to deliver their services,[13] they would be expected to contract with third-parties or ring-fenced affiliates to do so. As such, it is expected that the provision of NSP services would increasingly involve opex, rather than capex. This could include long-term contracted third-party solutions (i.e., greater than 10 years) to replace the NSPs' traditional network capex.

To support the achievement of the National Electricity Objective (NEO), the regulatory framework needs to incentivise NSPs to make efficient investment decisions, regardless of whether they use opex or capex.

The rest of this section describes how the regulatory framework treats opex and capex, and identifies the reasons why a bias in favour of capex might exist.

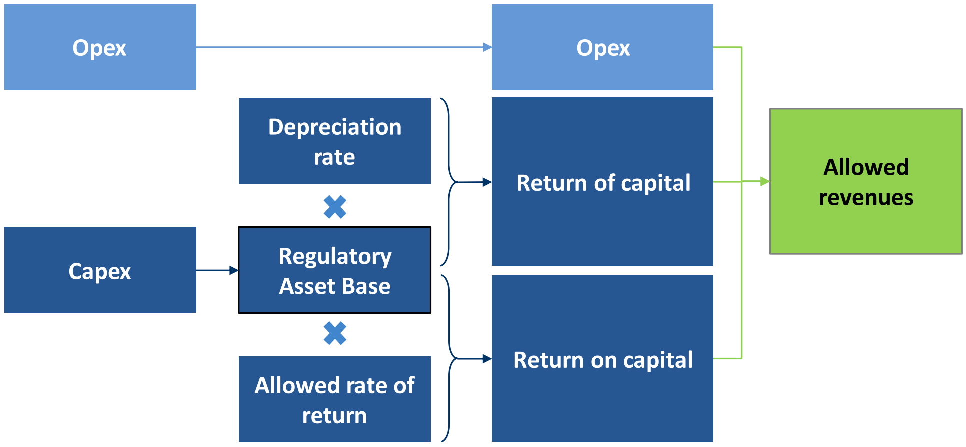
1.2. Regulatory treatment of opex and capex

The regulatory treatment of opex and capex under the NER building blocks framework is illustrated in Figure 1.1.

[12] AER (2017b).

[13] Specifically, we are referring to standard control services provided by DNSPs, and prescribed transmission services provided by TNSPs.

Figure 1.1: Illustration of the NER building blocks framework



Source: CEPA

Under the NER framework, opex is treated as an expense – customers pay for forecast opex in the year in which it is incurred. As it is assumed that there is no time lag between costs and benefits, opex generates no financial return. However, there is the potential for working capital requirements to cover any mismatch between revenues and opex. For this reason, regulatory allowances for asset-light businesses typically include a margin on opex as a way of enabling investors to earn a return to cover their working capital costs. For example, Ofwat's regulatory framework for water retailers in England and Wales allows the companies to charge prices that include a net margin above their cost allowance.[14] The working capital allowance needs to cover the risks associated with the companies' liabilities, as well as revenues. If their liabilities are seen to be riskier – for example, due to adopting innovative approaches to providing the services – then a higher margin might be required to cover these liabilities. The current regulatory framework for the NEM does not make a specific allowance for working capital costs and the risks associated with these. Rather, the AER considers that by assuming all cash flows (besides capex) occur at the end of the year, allowances provide sufficient coverage for working capital requirements. If the proportion of opex-related revenue increases (relative to revenue from the regulatory asset base (RAB)) then working capital requirements may need to be reassessed, particularly if there is increased uncertainty around opex.

Capex is treated differently. It is added to the RAB and then remunerated over the asset's life via the return *of* capital (depreciation) and the return *on* capital. The latter plays two roles:

- It compensates the NSP (and, in turn, its investors) for the time delay between when costs are incurred and when they are recovered through charges. By keeping NSPs and investors whole from a net present value (NPV) perspective, the return on capital and return of capital ensure financial capital maintenance.

[14] Ofwat (2014).

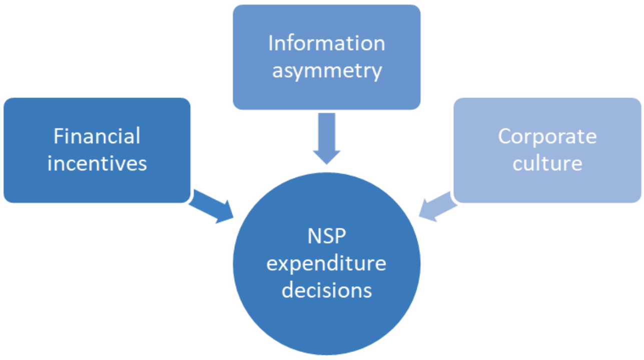
- It provides a signal to investors regarding the risk-adjusted opportunity cost of any capex that would be incurred during the current regulatory control period.

The AER sets the allowed rate of return based on its assessment of the weighted average cost of capital (WACC) of a 'benchmark efficient entity' (BEE). In theory, if the allowed rate of return is set correctly for each NSP – i.e. it exactly matches each NSP's true cost of capital – then investors in that NSP would be indifferent to whether management choose a capex or opex solution, if the outcome is the same. That is, investors would expect to achieve the same NPV return from opex remunerated in the same year as they would from capex remunerated over its asset life. In the next section, we discuss the reasons this assumption may not hold in practice.

1.3. What might cause a capex bias?

NSP decisions to pursue opex or capex solutions may be influenced by several drivers, as illustrated in Figure 1.2.

Figure 1.2: Drivers of NSP expenditure decisions



Source: CEPA

Financial incentives could encompass two types of considerations. Firstly, NSPs are likely to target long-term profit maximisation in response to the features of the regulatory framework. This is the Averch-Johnson effect of regulatory economics.[15] It is subject to several factors, including:

- How predictable and sustainable efficiency gains are (or are perceived to be) for opex and capex.
- The risk that the regulatory framework would not allow opex/ capex to be recovered. For example, whether costs are subject to an efficiency review or potential *ex post* adjustments and, if so, whether this is a one-off event or occurs at every determination.

[15] Averch et al (1962). This was the first identification of the problem of capex bias in utility regulation, demonstrating in a simple model the incentive for a utility both to substitute capex for opex and to expand output under conditions of asymmetric information.

- How the regulatory framework treats any over- or under-spend of opex and capex.
- Whether the allowed return on capital is higher than the NSP's actual cost of capital (one of the requirements of the Averch-Johnson effect).[16]

In addition to the financial incentives within the regulatory framework, an NSP might benefit from **information asymmetry** with regard to capex (i.e. over- and under-spends not being equally likely). It may be (or at least, be perceived) that NSPs are more able to take advantage of information asymmetries in the assessment process for capex, rather than for opex.

On a more qualitative level, there may be aspects of NSP **corporate culture** that could contribute to a preference for capex over opex. For example, it has been suggested that some NSPs (or their shareholders) are focussed on growing the RAB or, due to risk aversion, prefer to adopt traditional 'tried-and-tested' solutions.

1.4. Previous views and analysis on capex bias

While the implementation of regulatory regimes in other jurisdictions (and sectors) is different from the regulatory framework in the NEM, we consider it useful to look at what regulators, in addition to the AEMC and the AER, have said in regards to the existence of a capex bias. Where possible we have focused on regulators, and periods of time, when the regulatory framework was similar to the NEM.

Australia

As part of its Power of Choice review, **the AEMC** investigated whether a capex bias existed. It concluded that under the rules that operated at the time, there was "*a clear bias towards capital expenditure in favour of operating expenditure, both in terms of the potential to make profit and certainty about cost recovery*".[17] The AEMC noted that "*under the rules, all actual capital expenditure is rolled into the RAB….[h]owever, for any actual overspend in recurrent operating expenditure, the network business has to seek the regulator's approval that such higher levels of expenditure will be efficient in the future.* "[18]

However, several stakeholders have continued to make the case that a capex bias remains in the regulatory framework. For example, this issue was raised as part of the Demand Management Incentive Scheme (DMIS) rule change request. The AEMC noted that, regarding the choice between network solutions and non-network solutions, "*distribution businesses have no financial incentive to factor in the broader market benefits from non-network options*

[16] Related to this is the question of consistency in the cost of capital applied across all aspects of the regulatory framework. For example, we note that the EBSS is based on NSPs retaining efficiency benefits for a set period and a discount rate that differs from the allowed cost of capital, whereas the CESS has an *ex ante* sharing factor that also relies on a discount rate that differs from the allowed cost of capital.

[17] AEMC (2012a), page 25.

[18] Ibid, page 8.

and they may have limited incentives to trial new non-network options".[19] This observation led the AEMC to make a rule to introduce the DMIS, which is aimed at incentivising NSPs to adopt efficient demand management alternatives to network investment.

The AER explored the issues around capex bias in developing the DMIS. It noted that the different treatments of opex and capex under the NER building blocks framework could lead to a capex bias if an NSP (or its shareholders):[20]

- Prefers relatively stable long-term cash flows.
- Receives an allowed rate of return on the RAB that is above the NSP's actual cost of capital.
- Values the option to defer capex less than electricity consumers do. This is because NSPs are protected from the risk of overinvestment, as current rules protect the value of any investment once it has been added to the RAB.[21]

The AER cited the Institute for Sustainable Futures (ISF) 2017 report[22] that reviewed demand management (DM) incentives in the NEM. The report concluded that there were significant barriers to implementing cost effective DM, including that opex was treated less favourably than capex, that there was a bias in favour of network capex rather than non-network opex and that future 'option value' was excluded when considering DM solutions.

Concerns about the persistence of a capex bias were also behind a recent rule change request by the Australian Energy Council (AEC).[23] The AEC argued for further changes to the regulatory framework on the basis that it considers NSPs to be biased towards:

- capex over opex solutions;
- in-house approaches over outsourced approaches; and
- their own ring-fenced affiliates over third-party providers.

The AEMC committed to undertaking a review of the financial incentives as part of its 2018 Electricity Network Economic Regulatory Framework Review, which this report will inform.

Great Britain

Ofgem, the regulator for Great Britain's energy sector, was concerned about a capex bias created when it began to use building blocks in the more modern form we see today (this was during its third electricity distribution price control review in 1998). Frontier Economics' report for the AEMC on Totex Frameworks provides a brief history of Ofgem's statements on

[19] AEMC (2015), page i.
[20] AER (2017c), page 17.
[21] The AER does have the option to conduct *ex post* reviews of capex, but these are limited to certain instances, such as when an NSP has overspent its capex allowance on projects that do not meet the capex criteria.
[22] Dunstan et al (2017).
[23] AEC (207).

a capex bias and its approach to correct for this.[24] We agree with Frontier that there is no obvious empirical evidence that Ofgem relied upon to demonstrate a capex bias. However, we understand that Ofgem's key concerns stemmed from significant divergences in capitalisation policies across the NSPs and that the use of benchmarking for opex assessments (but not capex) might lead NSPs to opt for capex to appear more efficient.

Ofgem did not really begin to address the capex bias until its fifth price control (DPCR5). In DPCR5 it introduced the Information Quality Incentive (IQI) which included both capex and 'direct controllable' opex (this was opex that excluded business support costs). In the preceding price control (DPCR4), Ofgem introduced a capex 'sliding scale' incentive that was intended to reduce the incentive on companies to over-forecast and over-invest but did not include an incentive mechanism for opex. In its most recent price controls, Ofgem introduced a total expenditure (totex) incentive mechanism which treated almost all controllable opex and capex together and capitalised a proportion of the total expenditure. Alongside the totex incentive mechanism Ofgem also shifted to benchmarking totex (although this was not a requirement of using a totex incentive mechanism).[25] We note that Ofgem moved relatively quickly in introducing a totex regime; it was implemented in the first price control following the introduction of the standalone capex incentive mechanism.

Ofwat, the water regulator for England and Wales, published a discussion paper in 2011 after stakeholders raised concerns about a capex bias.[26] The paper investigated whether there was substance to this claim, whether there was a perception of a bias or whether it was simply a myth. Ofwat undertook consultations with stakeholders, reviewed case studies, modelled financial incentives, and considered non-financial incentives. Ofwat concluded that there was a wide-spread perception of a capex bias across the companies, which acted as a self-fulling belief. It found that companies' perceptions and behaviours reflected their understanding of the incentives, which were complex, and that their reaction was not always what the incentives were designed to achieve. Ofwat's price controls up to the 2011 report had included similar incentive mechanisms to the Efficiency Benefit Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS). Like Ofgem, Ofwat also introduced a totex incentive mechanism in its most recent price controls, as it did not consider that its separate incentive mechanisms were addressing the capex bias.[27]

An independent review into the water sector in England and Wales, undertaken by David Grey ('**the Grey Review**'),[28] also highlighted a perceived bias toward capital investment. He noted

[24] Frontier (2017).
[25] In DPCR5 Ofgem only used activity level benchmarking, and when it implemented 'totex benchmarking' for DNSPs it placed a significant weight on activity level benchmarking (75% during its initial [fast-track] determinations and 50% during its final [slow track] determinations).
[26] Ofwat (2011).
[27] Like Ofgem, Ofwat introduced 'totex benchmarking' that relied on a mix of models that covered totex, and opex plus base capex.
[28] Grey (2011).

that *"[m]any respondents argue that the companies have an incentive to pursue capital investment schemes, rather than potential alternatives, in order to enjoy the long-term return on the resulting addition to the Regulatory Capital Value (RCV)."*[29] The authors also found that the companies appeared to be very risk adverse and they expressed a concern that they might be penalised for inefficiency (due to the use of opex benchmarking) if they chose opex solutions rather than capex solutions. The risk adverse approach, coupled with a dependence on Ofwat to approve investment programmes at a relatively granular level, led companies to propose investment solutions because these could be defined clearly and approved by the regulator. The Grey Review included an extract from one of the regulated companies, Severn Trent Water, in which they state *"[c]apital investment increases companies' regulatory capital value, on which they earn a return. Operating cost solutions earn no return and higher operating costs lead to a lower comparative efficiency ranking, which adversely affects a company at price reviews. Therefore companies have an incentive to develop capital-based solutions rather than adopting solutions which might be potentially more innovative, or more cost effective, but are operating expenditure based."*[30] While both the authors' and Severn Trent Water's statement indicate that simply earning a return is a priority and they make no reference to this only being a positive when the actual WACC is higher than the allowed, we note that Ofwat may have 'aimed-up' when it set the WACC.[31]

New York

In 2015, the New York Public Services Commission (PSC) introduced a new regulatory framework for electricity utilities in New York state: 'Reforming the Energy Vision' (**NY REV**). The framework was developed with the objective of "*reducing the total energy bill to New York customers, and fully integrated to ensure optimal resource choices are made.*"[32] The PSC was concerned that there was a capex bias because of the rate of return framework and the fact that the utilities did not earn a return on opex.[33, 34] PSC staff stated that under the existing arrangements "*[u]tilities do not have a sufficient incentive to use third-party capital to provide service to customers, particularly when this reliance has the effect of increasing their operating expense... utilities will need both mechanisms to recover the expenses they incur to support the developing [DER services] market and opportunities to earn on them.*"[35] In response to stakeholders questioning whether there is an actual financial bias toward capex,

[29] Ibid, page 41.
[30] Ibid, page 42.
[31] Ofwat (2011), page 15.
[32] PSC (2015), page 1.
[33] In a white paper on ratemaking and utility business models, PSC's staff noted (PSC (2015), page 3) that "*Utilities' earnings are heavily dependent on their capital expenditures, and the long-term security of their earnings is based on the assumption of a growing or stable sales base. Further, utilities cannot earn a return on operating expenses, except by cutting them. Optimally integrating DERs may, though, require increases in utility operating expenses and decreases in capital spending.*"
[34] While NY State operated a different form of regulation to building blocks, it determines the rate of return in a similar way with the risk of providing the services being compensated by a fair return.
[35] PSC (2015), page 22.

as this should only exist where actual returns are expected to exceed allowed returns, the PSC staff note that "*[r]egardless of whether a capital bias has been demonstrated in the course of ordinary business…[given the reforms] utilities should not have a disincentive to use operating resources or third-party assets in lieu of utility capital investment, where the former are more efficient and effective.*"

Summary

Regulators have consistently pointed to the existence of a capex bias without necessarily being able to provide empirical evidence. Interestingly, there is a consistent view from regulators that companies seek to grow their RAB, as this is their primary source of returns. In some cases, the statements appear to focus more on the companies' desire to grow their RAB, rather than the theory that investors should only be interested in undertaking capex (instead of an opex solution with a lower expected present value cost) if their actual cost of capital is lower than the allowed rate of return. This may be due to an implicit or explicit upward bias in the allowed rate of return, or a recognition of the companies' risk aversion (or other behavioural factors).

Another common theme is that the networks only face an assessment of individual capex projects on their merits once; if approved, capex enters the RAB (unless subject to an *ex post* review). In contrast, opex is reviewed and benchmarked at each determination. Therefore, by choosing an opex solution, a network may expose itself to being assessed as inefficient.

1.5. Structure of the document

Following this introduction, this report is structured as follows:

- Section 2 sets out how a capex bias could be observed and provides a comparison of historical allowed and actual expenditure;
- Section 3 sets out the financial incentives within the current regulatory framework, commenting on the respective incentive strength for capex and opex efficiencies;
- Section 4 provides our findings from modelling the financial incentives;
- Section 5 details other factors that might contribute to a capex bias; and
- Section 6 presents our conclusions.

2. FINANCIAL INCENTIVES IN THE CURRENT FRAMEWORK

In this section we review the financial incentive mechanisms in the current regulatory framework for the NEM.

The framework includes incentives that influence how NSPs prepare their regulatory proposals (pre-allowance determination incentives) and incentives that influence their decision-making process once the determination is complete (post-allowance determination incentives). Although we describe these incentives separately, NSPs would consider any post-allowance incentives when developing their regulatory proposals.

The two key pre-allowance determination incentives are:

- **The approach to assessing expenditure proposals.** There is a general financial incentive on NSPs to gain high allowances to increase their scope for outperformance and cover the risk of outturn costs being higher than expected. The AER typically relies on revealed costs to set a base opex year to roll forward, with benchmarking employed to assess the efficiency of the base-year. As this needs to be reviewed at each determination, this is a repeated game. Capex requires an assessment of a greater range of 'bespoke' projects. As these are one-off assessments, the process is 'done-and-dusted' in a single determination.
- **The rate of return allowance.** The AER provides detailed guidelines on how it will determine the allowed rate of return. Therefore, the NSPs have reasonable visibility of what the allowed rate of return will be and thus their scope for out-/ under-performance on financing costs. This may influence decisions on what capex projects to include in the regulatory proposal.

There are three explicit financial incentive mechanisms that are intended to influence the NSPs during the regulatory control period (i.e., post-allowance determination incentives):

- The EBSS. This was designed to equalise the NSPs' incentives throughout the regulatory control period to achieve opex efficiencies.
- The CESS. This was designed to equalise the NSPs' incentives throughout the regulatory control period to achieve capex efficiencies. It was also intended to help balance the incentives between capex and opex.
- The DMIS. This was designed to encourage NSPs to appropriately consider demand side management solutions as an alternative to non-network solutions.

The combined effect of these incentives on NSPs is complex, and the NSPs' understanding and interpretation of these mechanisms may not be the response that was intended. Given the complexity, and the interaction with other cultural incentives, it is difficult to conclude how the combined incentives will influence the NSPs' decisions. However, the results of our incentive modelling suggest that it is not clear that the design of the EBSS and CESS do equalise the financial incentives between opex and capex.

The building blocks regulatory regime created by the NEL and NER places several financial incentives on the NSPs. These financial incentives have been developed and enhanced over time. Currently the expenditure related incentives on the NSPs include:[36]

- An allowed rate of return that is based on the Benchmark Efficient Entity (BEE).

[36] There are quality requirements placed on the NSPs to help ensure that NSPs do not avoid expenditure required to provide services to their customers.

- The EBSS. Introduced for use in determinations from 2008 and a new version (with minor updates) was introduced alongside the CESS in 2013.
- The CESS. Introduced for use in determinations from 2013.
- The DMIS. Introduced for use in determinations from April 2018 (including for existing determinations).

These financial incentive mechanisms are intended to work together to ensure that the NSPs choose the most efficient solutions to provide ongoing services to their customers. Before we discuss each of these incentives in turn below, it is important to set out our definitions of **incentive strength** and **sharing factors**:

- **Incentive strength**. In this report, incentive strength refers to the proportion of under-/over- spend that the regulated company retains/ bears relative to the length of a regulatory control period. If, for example, an NSP retained the full amount of an underspend for five years (the current regulatory control period length), then the incentive strength would be 100%.
- **Sharing factors**. Sharing factors are either:
    - an estimate of how much of the 'in perpetuity' value of any under-/over-spend a company retains/ bears; or
    - a fixed, *ex ante,* factor that applies directly to a company's under-/over-spend. In this case the fixed factor (for the company) will match the incentive strength.

There are two timeframes in which the incentives faced by the NSPs operate:

1. **Pre-allowance determination incentives.** Under the NER, the NSPs are required to submit their revenue proposals,[37] including capex and opex forecasts, to the AER.[38] The AER will then assess the capex and opex forecasts and either accept the NSPs' forecasts or substitute these with their own view. The NSPs have a specific set of incentives, financial and non-financial, in preparing their initial and revised proposals. These incentives may influence the NSPs' decision to propose capex or opex solutions.
2. **Post-allowance determination incentives.** After the NSPs receive their allowances, they will need to consider how best to respond to the within-regulatory control period incentives, such as the CESS and EBSS, when faced with the possibility to out-/ under-perform.

NSPs will almost certainly consider *both* pre-allowance incentives and post-allowance incentives in developing their proposals. For example, as we discuss below, any difference

[37] DNSPs are required to submit building blocks proposals while transmission operators are required to submit revenue proposals. For opex and capex forecasts there is no difference between these aside from their names.
[38] NER 6.5.6, 6.5.7, 6A.6.6 and 6A.6.7.

between the incentive strength on opex or capex from the CESS and EBSS will influence the NSPs' proposals, although the incentive applies post-allowance.

2.1. Pre-allowance determination incentives

2.1.1. The AER's assessment of forecast expenditure

Generally, NSPs have an incentive to obtain an expenditure allowance above their forecast of efficient costs to increase their opportunity to outperform (or provide protection against the downside risk of higher actual costs) and therefore increase investor returns. Part of the AER's role is to assess the NSPs' expenditure forecasts. Both **information asymmetry** and how **the AER approaches the assessment** of the NSPs' expenditure forecasts affect the NSPs' incentives at this stage.

Chapters 6 and 6A of the NER set out the objectives and criteria that the NSPs need to consider when preparing their building block/ revenue proposals. These objectives and criteria are also applied by the AER to determine whether to accept the NSPs' proposed cost forecasts, or to substitute their own assessment. The opex and capex objectives are the same, and they only differ across the DNSPs and TNSPs by reference to the services that are covered under the opex and capex objectives; DNSPs' services are *standard control services* while TNSPs' services are *prescribed transmission services*. The expenditure objectives are to:[39]

(1) meet or manage the expected demand for *standard control services/prescribed transmission services* over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of *standard control services/prescribed transmission services*;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

   (i) the quality, reliability or security of supply of *standard control services/ prescribed transmission services*; or

   (ii) the reliability or security of the *distribution/transmission system* through the supply of *standard control services/prescribed transmission services*,

   to the relevant extent:

   (iii) maintain the quality, reliability and security of supply of *standard control services/prescribed transmission services*; and

   (iv) maintain the reliability and security of the *distribution/transmission system* through the supply of *standard control services/prescribed transmission services*; and

[39] NER v106 6.5.6(a), 6.5.7(a), 6A.6.6(a), and 6A.6.7(a).

(4) maintain the safety of the *distribution/transmission system* through the supply of *standard control services/prescribed transmission services*.

The forecast operating and capital expenditure criteria are:

(1) the efficient costs of achieving the *[operating or capital] expenditure objectives*;

(2) the costs that a prudent operator would require to achieve the *[operating or capital] expenditure objectives*; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the *[operating or capital] expenditure objectives*.

The factors that the AER must have regard to in assessing opex and capex are also almost identical. The AER must take account of:[40]

- its most recent annual benchmarking report which covers both opex and capex, and total factor productivity. The extent of the benchmarking approach differs between TNSPs and DNSPs, with additional econometric benchmarking undertaken for DNSP opex.
- The NSP's historical performance against its allowances.
- The substitution possibilities between opex and capex.
- The extent to which the NSPs have considered non-network opex.

While the NER set similar objectives and obligations on the NSPs' expenditure forecasts and the AER's assessment of them, in practice the mechanics of developing the forecasts and assessing them are quite different. This may well impact the incentives for the NSPs.

For opex, the AER typically relies on a revealed cost base-step-trend assessment approach which relies on the assumption that opex is relatively consistent overtime.[41] The AER determines efficient opex in a base year, then applies step changes for opex not reflected in the base year and finally trends this forecast using input costs, productivity, and output growth. The AER can use benchmarking and other bottom-up approaches to assess efficient costs in the base year. However, the use of benchmarking to set efficient base year opex has so far been limited to the NSW and ACT DNSPs. In all other cases revealed costs have been used.

Because of this relatively mechanistic approach to determining the opex allowance, the NSPs will understand that revealing their efficient opex levels will affect their allowances in future regulatory periods. However, the only way for the NSPs to profit from opex outperformance is to achieve efficiencies above their allowance.

[40] NER v106 6.5.6(e), 6.5.7(e), 6A.6.6(e) and 6A.6.7(e).

[41] The base-step-trend approach is a top-down approach and the AER also use bottom-up assessments to support its base-step-trend analysis. However, if it substitutes an NSP's forecast it typically uses the base-step-trend approach.

Capex is a different story. While an NSP may seek to plan capex in a relatively smooth way, the capex profile is still heavily driven by the need to replace assets and the changes in demand across its network. While revealed capex is a useful input into the AER's assessment of future capex, and the AER can assess this alongside output measures, unit cost, and asset age/ health profiles, revealed capex does not play the same role as revealed opex. In addition, it is more difficult for the AER to independently assess the prudency and efficiency of specific capex projects, particularly for load related projects. This is because these often involve bespoke solutions that are not readily comparable across NSPs and therefore rely on (subjective) judgement around (a) the specific need for the capex (b) appropriateness of the solution, and (c) whether the expenditure associated with the proposed solution is efficient.

This means that there are likely to be greater **information asymmetries** around forecast capex compared to forecast opex, or at least longer-term asymmetries as opex will be revealed each five-year period.

Does this mean that there is a capex bias? This is not obviously the case if the NSPs' expected actual WACC is equal to the allowed rate of return. However, if we consider an example where an NSP is considering whether to propose a capex solution *or* an equally efficient opex solution which achieves the same outcome:

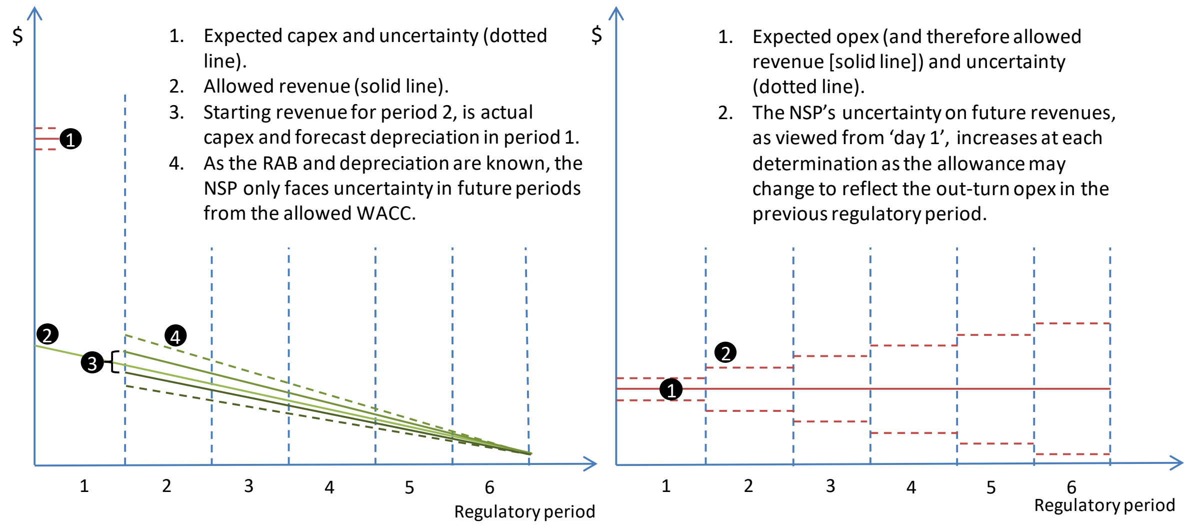
- There is greater uncertainty around the future allowances for an opex project.
  - If the NSP's approach to using opex solutions is out of sync with other NSPs, then it may appear inefficient in the benchmarking. It may be able to request an operating environment factor; however, this would require the NSP to prove why it should get an uplift for these costs. It would be subject to this for the duration of the opex solution.
  - The opex solution is exposed to input price and productivity changes that may be above or below the AER's expectation.
- For a capex project, the NSP is exposed to the risk/reward that its future actual cost of capital may be higher/lower than the allowed level.
- There is also a potential behavioural bias to capex solutions that may be due to risk aversion and/or a preference for established engineering approaches.
- The AER can also conduct an *ex post* review of capex; however, this is only when an NSP overspends against its allowance. While this encourages NSPs to underspend to avoid this review, it also may create an incentive for them to seek higher capex allowances to provide *headroom* to avoid the review.

We illustrate the dilemma facing NSP management when choosing a capex or opex solution in Figure 2.1 below. Without losing the generality of the example, we assume that:

- the opex solution delivers the same outcomes as the capex solution;
- both solutions result in the same PV costs;

- the NSP's actual WACC equals the allowed rate of return; and
- the EBSS and CESS do not apply.

Figure 2.1: Difference between revenue flows (LHS = capex, RHS = opex)



Source: CEPA

On the **left-hand side chart**, we have the example of an investment in capex in the first year of the first regulatory control period and the resulting revenue flows to the NSP. The NSP faces uncertainty around the actual capex (illustrated by the red dotted lines) due to design, input price changes, etc. Once the capex is added to the RAB the NSP is likely to receive relatively stable revenue flows for the rest of the asset's useful life. This is because depreciation is fixed and therefore the remaining RAB at each period is known. The only uncertainty stems from the return on capital, as the allowed rate of return is reset at each determination (illustrated by the green dotted lines). As the RAB decreases over the life of the asset, the share of revenue subject to this uncertainty decreases. If there is an overspend (the top solid line) then the NSPs RAB will be increased at the start of the second regulatory control period to reflect this (as actual capex and forecast depreciation are used to roll forward the RAB). An underspend (bottom solid line) will result in a lower RAB.

On the **right-hand side chart**, we have an example of an opex solution being employed. Revenue is equal to opex.[42] Because the AER reassess the opex allowance at each determination, the NSP will face uncertainty from changes in input prices (e.g., wages), required volumes (e.g., hours), whether any overspend will be allowed by the AER, or if its allowance will be adjusted down for any underspend. Therefore, the longer the opex solution lasts, the greater the uncertainty will be at the point at which it is implemented. In addition, as noted in ElectraNet (2018), contracted non-network services include *"contractual risk and compliance risk"* and *"the TNSP retains service delivery accountability whereas contractual*

[42] The NSP only earns a return it if can outperform its opex allowance and loses money if it under-performs against its allowance.

arrangements can never perfectly contract - and nor are counterparties willing to accept - this risk in full."[43]

Overall, we consider that NSPs have a financial incentive to increase both their capex and opex forecasts to improve their scope for outperformance, although there may be reputational incentives that offset this to some extent. Due to differences in the assessment of the expenditure types, NSPs may find it more attractive to put forward a capex solution rather than an opex solution. This does not prevent an NSP from choosing an opex solution after receiving its determination. However, as we discuss below, this depends on the incentives *during* the regulatory control period.

2.1.2. Rate of return allowance – Benchmark efficient entity (BEE)

The National Electricity Rules (NER) specify that:

> *"The allowed rate of return objective is that the rate of return for a …[NSP]… is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the …[NSP]… in respect of the provision of standard control services (the allowed rate of return objective)."*[44]

As the NER require that the allowed rate of return is set for the NSPs based on the BEE, there is scope for the NSPs to out-/ under-perform against the allowed rate of return.

If an NSP considers that it can outperform the allowed rate of return (i.e., achieve financing at a lower rate or that the allowed cost of equity is higher than required) then it may favour capex solutions, as these will increase the RAB. If it considers that it will under-perform against the allowed rate of return, then it may reduce capex and/or favour opex.

The NSP will retain/ bear all the difference between its actual WACC and the allowed rate of return.

The AER's Rate of Return Guidelines, which are to become binding guidelines,[45] are published in advance of the AER making its determinations. Therefore, the NSPs are aware of the approach to estimating the allowed rate of return and will be able to estimate what their rate of return allowance will be at the time of putting together their building blocks/revenue proposals.

At this stage, the NSPs will assess whether their expected actual cost of capital is likely to be above or below the allowance:

[43] ElectraNet (2018), page 2.
[44] NER, v106, clauses 6.5.2(c) and 6A.6.2(c).
[45] Draft legislation to affect this decision by COAG (Statutes Amendment (National Energy Laws) (Binding Rate of Return Instrument) Bill 2018, v08, 20 February 2018.

- If the NSP believes it can ***outperform*** the allowed cost of capital then it may have a financial incentive, to the extent a trade-off is possible, to propose capex instead of opex.
- If the NSP expects to ***under-perform*** the allowed cost of capital then it may have a financial incentive, to the extent a trade-off is possible, to propose opex instead of capex. However, as noted above, in this case this means increasing its opex forecast which the AER will assess using a base-step-trend approach.

After the allowed rate of return for an NSP has been announced, its decisions during the regulatory control period will be based on the incentives within the framework.

A further financial incentive that may influence an NSP's expenditure decisions is likely to be the desire to minimise their exposure to systematic risk. An NSP's cost of capital would increase with greater exposure to systematic risk via the beta component of the cost of equity, so the NSP is incentivised to minimise exposure to systematic risk to improve its chances of outperforming the allowed rate of return. For example, if an NSP's main source of systematic risk relates to opex cash flows (e.g. labour costs), it may favour capex solutions over projects with substantial opex components, as the latter would tend to increase its exposure to systematic risk. It is also important to consider how company-specific risk may affect the incentives. While investors can diversify away company-specific risk (this is an underlying assumption of the cost of capital), they should still be concerned that companies' management appropriately manages business risk. If the company engages in more 'risky' solutions (for example, moving away from tried-and-tested capex solutions) this may increase the volatility around investors' expected returns. In addition, it is also important to bear in mind that debt providers are concerned about business-specific risk. Debt providers, unlike equity investors, have no upside on their expected yield but face the downside risk that their yield may be lower if a project or company fails or under-performs. Therefore, debt providers may require a higher promised return to reflect the companies' specific risk.

2.2. Post-allowance determination incentives

In this section, we discuss the incentives that apply once an NSP has received its revenue determination.

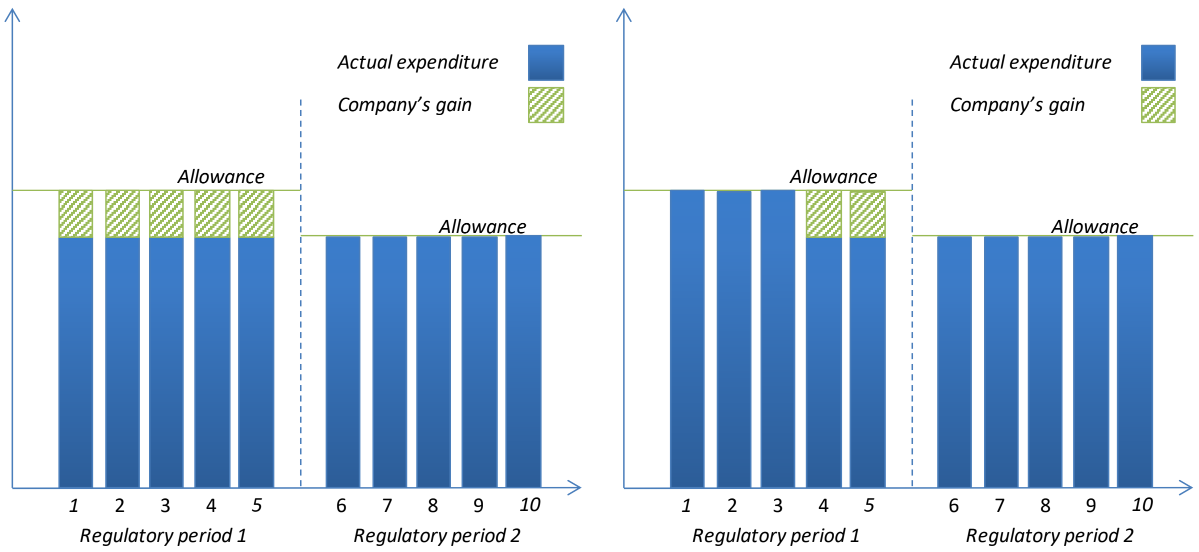
2.2.1. Efficiency Benefit Sharing Scheme (EBSS)[46]

The EBSS only applies to opex. The EBSS was introduced to solve two incentive issues in the regulatory framework, which are particularly prominent when using a base-step-trend approach: [47]

1. NSPs had an incentive to increase costs in the base year, to increase allowances for the subsequent regulatory period.
2. NSPs' incentives to make ongoing efficiency savings decreased as the regulatory period progressed, towards the next period's base year. This is because the NSP would only retain savings made up to the base year.[48]

The latter issue is illustrated in Figure 2.2 below. In the LHS figure, if the NSP makes a recurring saving in Year 1, then it keeps the gains for five years before the allowance is reset to the new efficient opex level. In the RHS figure, if the NSP makes a saving in Year 4, then it only keeps it for two years before the allowance is reset for the next control period.

Figure 2.2: Incentive strength over time (without EBSS)



Source: CEPA

The EBSS allows the NSP to keep any recurring (permanent) savings for a period of six years regardless of when the saving is made.[49] This is illustrated in Figure 2.3 below. The LHS figure shows that if the NSP makes a recurring saving in Year 1, it will retain this saving for six years.

[46] The EBSS was first introduced in 2008 and reviewed in 2013. The EBSS was largely unchanged following the 2013 review.

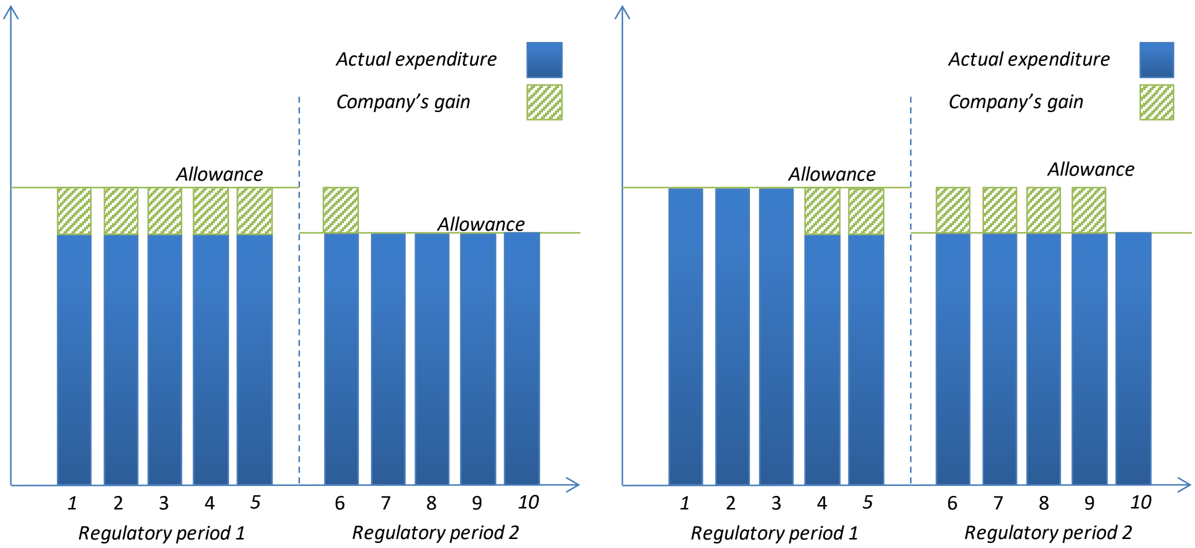
[47] This approach relies on revealed costs in the base year as a starting point, adjusting this for any one-off expenditure, then adding a 'step' for any additional opex not reflected in the base year, and finally applying a 'trend' for productivity, output and input price changes.

[48] AER (2013b), page 6.

[49] The mechanics of the EBSS can be found in AER (2013b).

The RHS figure shows that the NSP will retain a saving made in Year 4 for six years, until Year 9.

Figure 2.3: Incentive strength over time with the EBSS



Source: CEPA

The incentive is symmetric, in that if the NSP has a recurring overspend it bears the costs for six years. The **incentive strength** for permanent savings/ over-spends is over 100% as the NSP will retain/ bear the savings/ over-spends for longer than a single regulatory period. The retention period of the savings is the incentive strength of the EBSS. For temporary underspends or overspends, the NSP only receives/ bears the time value of money.

In addition to the incentive strength, regulators also focus on the **sharing factor** (or rate). The AER relies on a savings-in-perpetuity calculation to determine its estimate of the sharing factor. The AER's opex sharing factor is based on companies keeping the efficiency savings for six years with a real discount rate of 6%. This means that if a company makes a recurring $10 saving it retains that benefit for six years. After discounting, the recurring saving is equal to $52. The total 'savings' in perpetuity are $167,[50] therefore the consumers' share is $115 (or approximately 69%). The headline sharing factor for the NSP is therefore approximately 30%. That is, the NSP retains (bears) 30% of under- (over-)spends while consumers receive (bear) 70% of under- (over-)spends.

The sharing factor estimate is dependent on the regulator placing 100% weight on the revealed costs in setting allowances during the next period and into the foreseeable future. If the regulator uses benchmarking or makes an independent assessment to set allowances for the next regulatory period, i.e., placing less weight on the revealed costs, then it could be

[50] $167 = $10/6%.

argued that consumers would benefit from efficiency gains without additionally rewarding the company.[51]

Therefore, there are two important takeaways in relation to the EBSS:

- The 30% sharing factor does not reflect the financial incentive on the NSPs for under-/over-spending on opex. Rather, this is determined by the retention of under-/over-spends for six years.
- The use of exogenous forecasts (i.e., benchmarking) rather than a base-step-trend approach changes the incentive properties.

2.2.2. Capital Expenditure Sharing Scheme (CESS)

The CESS only applies to capex.[52] It was introduced in 2013 to work alongside the EBSS, primarily to equalise the incentive to make capex savings over the regulatory period, but also to avoid inefficient substitution between opex and capex.[53] Like opex, the NSPs' incentive to underspend (or avoid overspends) on capex diminishes as the regulatory control period progresses. This is because the RAB is adjusted for actual capex when rolled forward at the start of the next regulatory control period. Therefore, any benefit – the difference between forecast and actual depreciation and the difference between forecast and actual return on RAB – from underspending capex at the start of the period is retained for five years, while the benefit of an underspend later in the period is retained for a shorter time. The AER cited three key reasons why the declining incentive may be an issue:

1. As the incentive to underspend (or avoiding overspending) at the end of the period is low, the NSPs may not be disciplined in their approach to capex towards the end of the period.
2. It could distort decisions on whether opex or capex solutions should be used. This is because the opex incentive over the period is equalised through the EBSS.
3. Capex may be less efficient if undertaken at the end of the period. The AER cite concerns that projects delayed until the end of the period may create a capacity issue requiring the use of more external contractors and/ or less cost-effective contracts.[54]

Because of the differences between how capex and opex are remunerated, the CESS mechanism needs to be different from the EBSS. Rather than setting a savings retention period, the AER rely on the in-perpetuity calculation from the EBSS to set, *ex ante*, both the **incentive strength** and **sharing factor** for the CESS at 30%. The 30% factor is applied to any under-/over-spend across the entire regulatory period, with a discount factor applied to

---

[51] The AER illustrate this in Annex B ("How the EBSS interacts with an exogenous forecasting approach") of AER (2013b).
[52] NER v106 clause 6A.6.5A.
[53] AER (2013a), page 10.
[54] AER (2013a), pages 24-25.

convert the differences between actual and forecast capex into a net present value (NPV).[55] It is important to note that the sharing factor is applied pre-tax, therefore the NSPs will pay tax on any retained underspend which reduces their overall benefits.[56] The NSPs also pay tax on opex savings retained.

Alongside the *ex ante* sharing factor, the AER (in most circumstances) rolls forward the RAB using actual capex and forecast depreciation. The AER stated that the use of actual depreciation would lead to higher powered incentives than the intended 30%.[57]

It is important to note that the CESS creates a stronger incentive for NSPs to defer capex, particularly at the end of the period, and re-propose it for their next regulatory period. These deferrals may be efficient and therefore benefit consumers where they do not impact on the NSPs' forecast capex plans for future regulatory periods. However, deferrals may result in consumers paying the CESS reward and funding the capex in the following period.[58] The CESS allows for adjustments to the CESS payments where "a material amount of capex is deferred between regulatory control periods."[59]

In addition, unlike opex, the AER can scrutinise an NSP's capex on an *ex post* basis – albeit under certain conditions only. Where it deems that some capex may have been inefficient or imprudent, it can remove this capex from the RAB and reverse any penalty/ reward provided by the CESS.

2.2.3. Demand Management Incentive Scheme (DMIS)

In August 2015, the AEMC published its final rule determination setting out revised arrangements to incentivise DNSPs to adopt demand management solutions instead of network projects, where this would be more efficient.[60] The rule change was in response to stakeholder concerns that under the prevailing regulatory framework, DNSPs were biased towards network investment over alternative options. The rule change established two parts to the demand management incentive framework:

i. The **demand management incentive scheme** (DMIS), which provides DNSPs with the opportunity to earn financial rewards for implementing efficient non-network projects that deliver net cost savings to consumers.

ii. The **demand management innovation allowance** (DMIA) which makes funding available to DNSPs for research and development of non-network solutions with the potential to reduce long term network costs.

[55] AER (2013a), Attachment B provides worked examples.
[56] Similarly, their tax will be reduced for overspends.
[57] Economic Insights (2012).
[58] This point was made in ESC (2006), page 432, in its decision to remove a capex carryover mechanism.
[59] AER (2013a), page 12.
[60] AEMC (2015).

While the DMIA may increase the non-network solutions available to or recognised by DNSPs (the DMIS and DMIA only apply to DNSPs), we do not consider that it would impact a capex/opex trade-off decision at a given point in time. Therefore, we focus here on the DMIS.

In December 2017, the AER published its final design for the DMIS.[61] For each DNSP, the DMIS will be implemented according to the steps outlined below:

i. Through its distribution determination, the AER will set out how (if at all) the scheme will apply to the DNSP during its regulatory control period.

ii. DNSP identifies **eligible projects**, which must: be the preferred option to meet an identified need on the distribution network; must have a positive NPV when assessed against the status quo (unless for reliability corrective action); and have been assessed as the preferred option through either the Regulatory Investment Test for Distribution (RIT-D) or the minimum project evaluation requirements[62]. A project becomes **committed** when the DNSP enters into a contract to procure the required DM from a third party, or internal approval is granted for self-provision of the DM project.[63]

iii. DNSP calculates the **project incentive** for committed projects. The project incentive is capped at the lower of: (a) the expected present value of the project's DM costs (net of subsidies) multiplied by the **cost multiplier** or (b) the expected present value of the project's net benefit (calculated through a cost-benefit analysis).

    The cost multiplier under the current DMIS is **50 per cent**. While the AER may vary this, the multiplier prevailing at the time an eligible project becomes a committed project will continue to apply for that project.

iv. DNSP prepares and submits an annual DM **compliance report** to the AER, setting out the details of both committed and eligible projects.

v. Based on the compliance report, the AER determines the **total financial incentive** available to the DNSP for each year of its regulatory control period. This includes adjustments for projects previously committed, but not fully implemented. The total financial incentive that a DNSP may accrue across all committed projects is capped at 1 per cent of their allowed annual revenue for that year.

vi. The total financial incentive for year *t-2* will then be included in the DNSP's total revenue allowance for year *t*.

[61] AER (2017c).

[62] As set out in the AER's final DMIS design, clause 2.2.1.

[63] The DMIS is neutral on whether the DM project is procured from a third-party or implemented in-house if this is consistent with other aspects of the regulatory framework. For example, this would include the ring-fencing guideline and other restrictions, such as limitations on whether behind-the-meter assets can be included in a DNSP's RAB.

The DMIS can operate as both a pre- and post-allowance determination incentive.

2.3. Summary

The discussion above highlights the complexity of the incentives faced by NSPs. Consequently, there is a risk that when combined, the different incentives may not produce their intended outcomes. Each NSP needs to work out how it responds to these incentives and their understanding may differ from what the designers of the incentives intended.

We provide a high-level summary of how the factors above may influence the financial decisions of NSPs in Table 2.1 below.

Table 2.1: Summary of financial incentives

Factor/ incentive mechanism	Influences
Expenditure assessment	• Broad incentive to seek high expenditure allowances to create a greater chance of outperformance or cover risks from higher outturn costs. • Lower future opex allowances from revealed efficiency gains. • Capex assessment typically 'one-off' based on merits of individual projects.
Rate of return	• Incentive to outperform a broad BEE target rate of return allowance. • More 'risky' innovative or alternative opex solutions may increase volatility around the expected return.
EBSS	• Equalises the opex incentive over the regulatory period. • Strong financial incentive to decrease opex, although this leads to a reduction in base opex.
CESS	• Equalises the capex incentive over the regulatory period. • Ex ante proportion of over-/ under-spend retained by the NSP.
DMIS	• Specific revenue reward to encourage NSPs to consider demand management solutions. • Can influence NSP decisions pre-allowance and post-allowance.

We cannot model an NSP's response to these incentives. However, in the following sections, firstly, we review how we might measure the NSPs response from available data and secondly, we model the interaction of the incentives to determine whether there might be an overall financial incentive on the NSPs to prefer opex or capex solutions.

3. Observable indicators and a review of actual versus allowed expenditure

In this section we set out how a capex bias might be observed. We identify four potential indicators:

- Changes in opex and capex over time, with an increasing capex to opex ratio indicating a bias.
- Out-/ under-performance against the incentives.
- Evidence that NSPs have chosen a less optimal capex solution over an opex solution.
- Evidence that NSPs are not considering opex solutions.

For all these indicators there is a lack of a counterfactual (bias free scenario) to compare with, although it is conceivable that project-specific counterfactuals could be developed for the latter two indicators, using engineering judgement. The lack of available counterfactuals limits the usefulness analysing historical data.

In relation to the first indicator, it is difficult to disentangle the effects of incentives from other factors. These include: changes in NSP capitalisation policies; changing customer requirements; changing technology; changes in the NEM and the introduction of different incentive mechanisms; and changing input costs. Because of these factors, it is difficult to review a long, consistent time series for the NSPs. Therefore, we do not consider that we can draw concrete conclusions from the trends in the capex to opex ratio.

In relation to the second indicator, we have reviewed Regulatory Information Notice (RIN) data from the DNSPs for their most recently completed regulatory determinations.[64] From this, we find that over this period DNSPs generally outperformed their capex allowances (only three under-performed), but only four outperformed their opex allowances. However, because forecast demand did not eventuate, augmentation capex was not required and therefore the capex outperformance is likely to be higher than under a counterfactual where forecast demand did eventuate. All the TNSPs outperformed both opex and capex, although their capex outperformance was significantly higher.

In relation to the third and fourth factors, we note the AER's observation that across the RIT-Ds completed to date, non-network solutions may not have been considered consistently.

Given the lack of a counterfactual and our inability to disentangle the different factors influencing the NSPs' spending, based on the historical data we cannot conclude whether there is a capex bias or not.

3.1. Indicators

In this section we set out the ways that a capex bias might be observed. We identified four potential indicators:

1. Relative changes in opex and capex over time.
2. Out-/ under-performance against the incentives.
3. Evidence that NSPs have chosen a less optimal capex solution over an opex solution.
4. Evidence that NSPs are not considering opex solutions.[65]

[64] 2009/10 to 2013/14 for the NSW and ACT and 2011 to 2015 for QLD, SA, and VIC.
[65] These are similar to those identified in Ofwat (2011).

The first two indicators can be quantitatively observed, while the latter two are typically qualitative and rely on judgement as to whether the NSPs are considering opex solutions appropriately.

One issue with the first two indicators is that there is no counterfactual which we can compare them against. There is also a myriad of factors that could influence the observed indicators – these include changes in demand, input price changes and data limitations, among others.

In the case of the last two factors, it is conceivable that project-specific counterfactuals could be developed, in order to assess whether a more optimal opex solution exists. This is similar to the approach taken by the 2017 IFS study.[66] Given the need for engineering judgements and project-specific analysis, we have not undertaken a similar assessment for this paper. However, we note the analysis reported by the AER as part of the ongoing Regulatory Investment Test (RIT) application guidelines review.

3.1.1. Capex to opex ratios

In relation to the first indicator, a capex bias could potentially be identified by increasing capex relative to opex. However, there is limited time series data available for the NEM NSPs with a consistent regulatory framework and it is difficult to disentangle the effects of incentives from other factors. These include:

- changes in capitalisation policies;
- changing customer requirements, such as demand growth/ reductions;
- changing technology;
- changes in the NEM and introduction of different incentive mechanisms; and
- changing input costs.

For example, the available data for the most recently completed DNSP regulatory control periods (2009-2015[67]) covers a period where actual demand was much lower than forecast and therefore augmentation capex fell away significantly.

For the reasons outlined above, particularly changes in the regulatory framework, it is difficult to establish a long, consistent time series for the NSPs. Therefore, we cannot draw any conclusions from this indicator.

3.2. Out-/ under-performance – actual versus allowed expenditure

Several interpretations could be drawn from out-/ under-performance:

[66] IFS (2017).

[67] For ACT and NSW this is the 2009/10 to 2013/14 period, 2010/11 to 2014/15 period for QLD, and 2011 to 2015 period for VIC and SA. For TasNetworks the average is from 2013 to 2015 only and category RIN data for Ergon and Energex was not available on the AER's website for 2013/14.

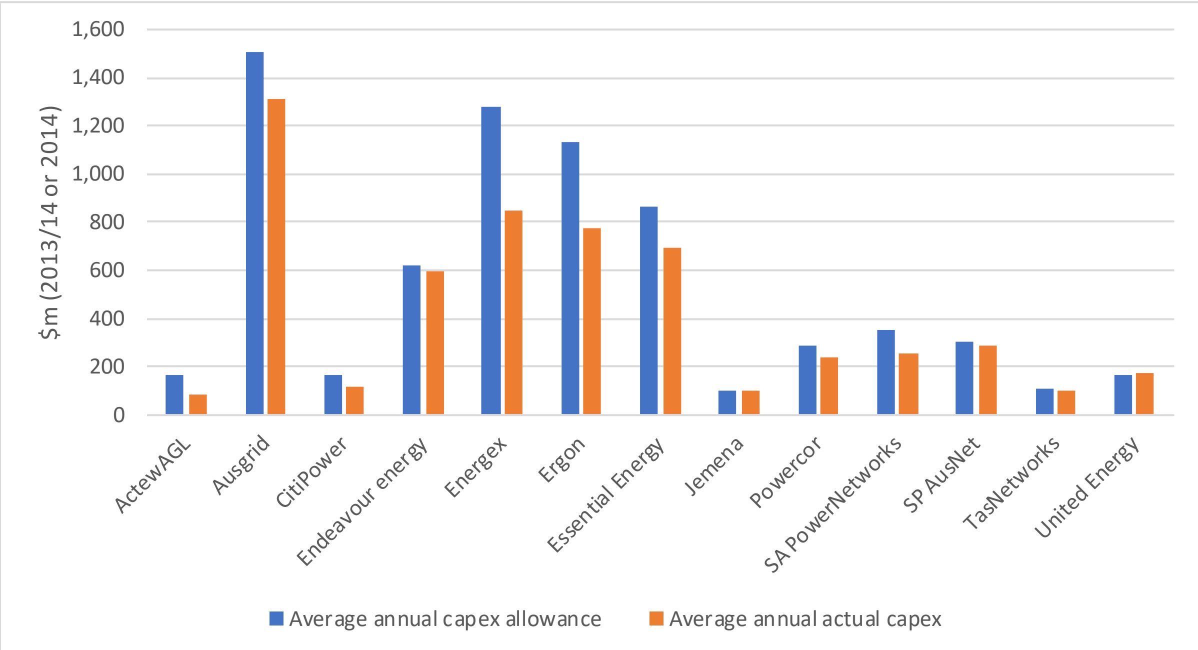
- Relatively high levels of capex outperformance compared to opex could indicate information asymmetries i.e., that NSPs are putting forward additional capex, as it is relatively harder to assess (see our discussion on this in Section 2.1.1).
- Relatively high/ low levels of capex outperformance could be driven by demand being lower/ higher than forecast.

We present evidence comparing NSPs' actual and allowed expenditure for their most recently completed regulatory control periods. The data on their allowed expenditure was derived from the AER's final decisions, corrected for any successful appeal, and the data on actual expenditure was sourced from the category Regulatory Information Notices (RINs). The EBSS was in place for these regulatory control periods, however the CESS and DMIS had not been introduced.

3.2.1. Distribution NSPs

Figure 3.1 below sets out the average annual allowed and actual net capex (gross capex less customer contributions) for each DNSP's most recently completed regulatory control period. We can see that the majority of DNSPs, apart from Jemena and United Energy, outperformed their capex allowances.

Figure 3.1: DNSP total average annual real allowed and actual net capex[68]



Source: CEPA analysis of AER determinations and annual RINs

The capex underspending was largely driven by:[69]

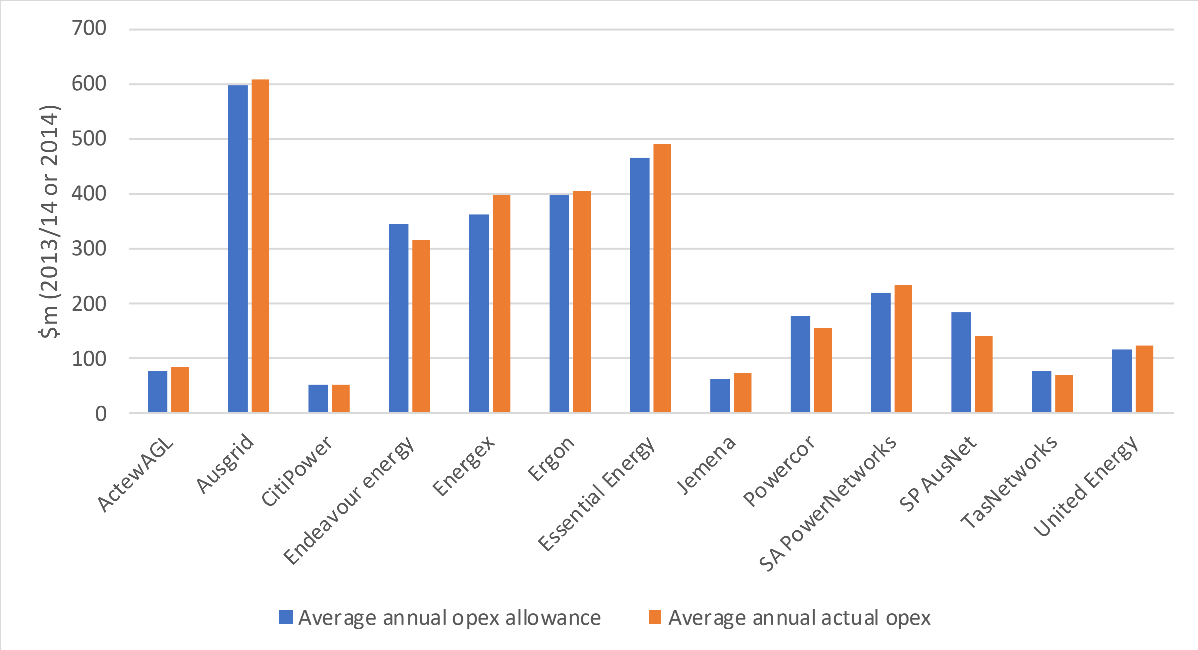
[68] For ACT and NSW this is the 2009/10 to 2013/14 period, 2010/11 to 2014/15 period for QLD, and 2011 to 2015 period for VIC and SA. For TasNetworks the average is from 2013 to 2015 only and category RIN data for Ergon and Energex was not available on the AER's website for 2013/14.

[69] AER (2015b), page 22.

- Lower actual demand than forecast, therefore augmentation projects were deferred or avoided.
- DNSPs actively seeking to reduce the need for capex.
- Improvements in risk management that led to a reduced volume of works.

Figure 3.2 below sets out the DNSPs' average annual allowed and actual controllable opex. In contrast to capex, the majority of DNSPs under-performed against their opex allowances.

Figure 3.2: DNSP total average annual real allowed and actual opex[70]



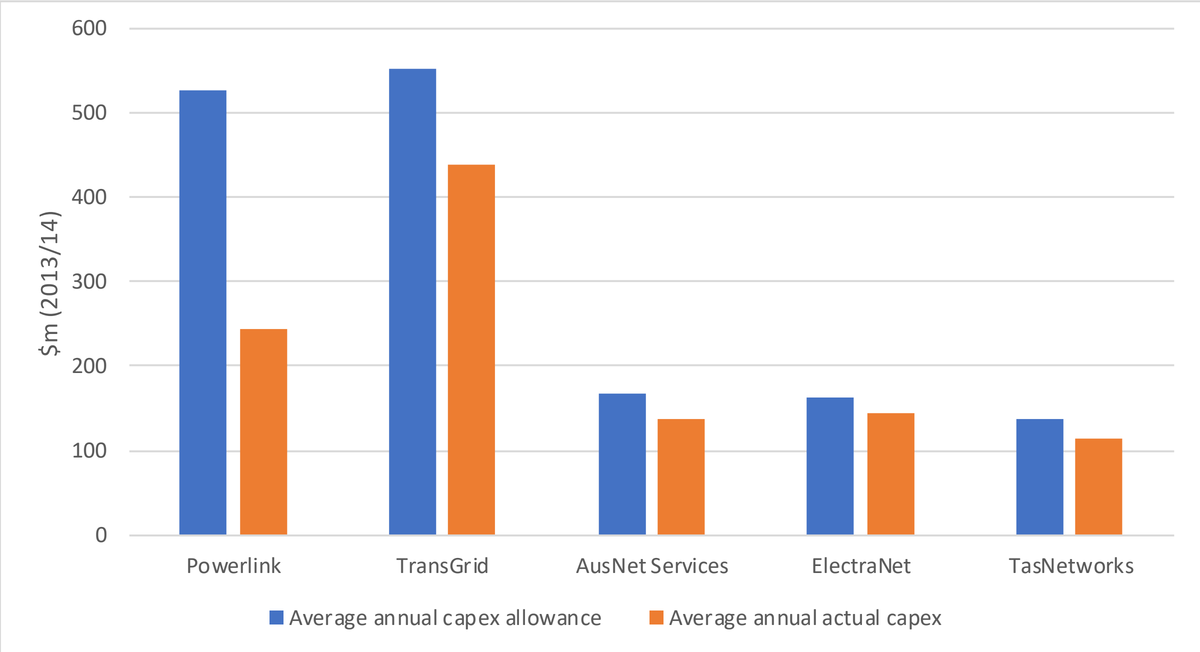
Source: CEPA analysis of AER determinations and annual RINs

3.2.2. Transmission NSPs

Figure 3.3 below sets out the average annual allowed and actual net capex (gross capex less customer contributions) for each TNSP's most recently completed, or mostly complete, regulatory control period (we have included ElectraNet's current regulatory control period as there is four years of data available). We can see that all the TNSPs outperformed (or are outperforming) their capex allowances.

[70] For ACT and NSW this is the 2009/10 to 2013/14 period, 2010/11 to 2014/15 period for QLD and SA, and 2011 to 2015 period for VIC. For TasNetworks the average is from 2013 to 2015 only and category RIN data for Ergon and Energex was not available on the AER's website for 2013/14. For Ergon and Energex, we have removed the solar feed-in-tariff payments.

Figure 3.3: TNSP total average annual real allowed and actual net capex[71]



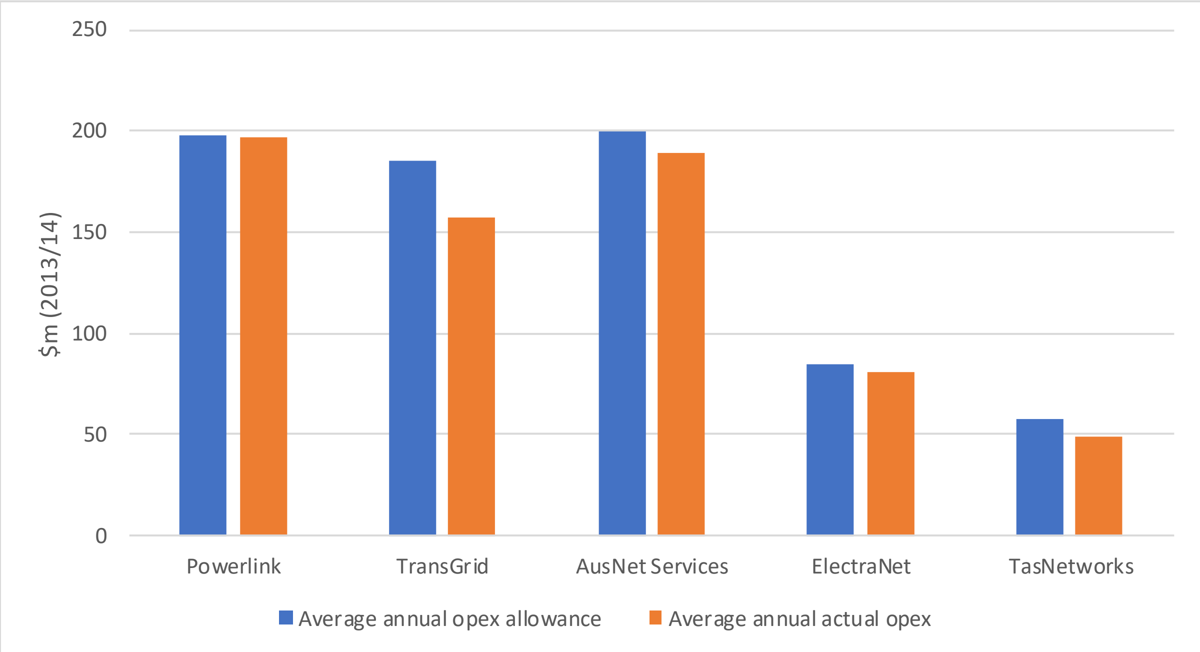
Source: CEPA analysis of AER determinations and annual RINs

The regulatory control periods that we reviewed for TransGrid and TasNetworks include the lower outturn demand period. Regulatory control periods for the other TNSPs commenced after demand had dropped compared to forecasts.[72]

Figure 3.4 below sets out the TNSPs' average annual allowed and actual controllable opex. The TNSPs also outperformed their opex allowances, although to a lesser extent than their capex outperformance.

[71] The regulatory control periods covered are: Powerlink 2012/13 to 2016/17; TransGrid 2009/10 to 2013/14; AusNet Services 2014/15 to 2016/17; ElectraNet 2013/14 to 2016/17; and TasNetworks 2009/10 to 2013/14.
[72] Overall NEM electricity consumption began falling from around 2009/10.

Figure 3.4: TNSP total average annual real allowed and actual opex[73, 74]



Source: CEPA analysis of AER determinations and annual RINs

3.3. Evidence of inefficient investment decisions, or insufficient consideration of opex solutions

In principle, the RIT process could provide a potential source of information to assess whether capex and opex alternatives to meet identified network needs are being appropriately considered. In particular, the NER set out requirements for the RIT-D process to include screening of potential non-network options. Specifically, a RIT-D proponent must either:

- publish a non-network options report, to assist non-network service providers to propose alternative options for consideration in the RIT-D; or
- if the proponent determines that non-network options cannot form part of a credible option to address the identified need, they must publish a notice setting out their reasoning.

While not subject to the same provisions as the RIT-D, the RIT-T process still requires TNSPs to consult on credible options. A key feature of the RITs is to increase the amount of information available to stakeholders.

We have not independently reviewed the analysis of non-network options undertaken by NSPs in line with these requirements. However, we note below the AER's analysis as part of the ongoing RIT application guidelines review.

[73] The regulatory control periods covered are: Powerlink 2012/13 to 2016/17; TransGrid 2009/10 to 2013/14; AusNet Services 2014/15 to 2016/17; ElectraNet 2013/14 to 2016/17; and TasNetworks 2009/10 to 2013/14.
[74] This includes network support costs, debt raising costs and movements in provisions. We note that the AER's presentation of out-/ under-performance in its determinations excludes these costs.

To date, the RIT-D has been applied 17 times, with 11 of the RIT-Ds including publication of a non-network options report. Six of the RIT-Ds that included a non-network options report have been completed, with a non-network solution being identified as the preferred option in one case. However, the AER have noted that *"[o]ur assessment of the RIT–Ds undertaken to date has shown that there have been inconsistent levels of non-network engagement and information in reports, particularly in the non-network options report."*[75]

At the stakeholder workshop, NSPs noted that while the incentives played a part in the decision-making process, their key focus was on practical considerations, such as the impact on outages and what the enduring need was. It was also mentioned that the risks associated with any option needed to be considered in assessing the options and opex solutions were more likely to have a higher risk than capex ones.

3.4. Summary

As noted at the start of this section, because of the lack of counterfactual and the myriad of factors that drive expenditure decisions it is difficult to conclude anything concrete from the available evidence. One could argue that the out performance on capex indicates potentially greater information asymmetries. Alternatively, the outperformance (or lack thereof) against opex could indicate a lower financial incentive compared to capex. However, both arguments are not robust to scrutiny as this covers a period where demand forecasts were materially inaccurate.

In addition to the above points, it is important to bear in mind that the package of incentive schemes has only just been completed. The DMIS has yet to be used and the NSPs are only in their first regulatory control period with the CESS applying.

[75] AER (2018), page 26.

4. MODELLING THE STRENGTH OF THE FINANCIAL INCENTIVE MECHANISM

In this section, we present our modelling results of the financial incentives that apply to equivalent opex or capex solutions.

Our model uses the underlying assumptions and mechanisms from the AER's post-tax revenue, roll forward, EBSS and CESS models.

We have considered the financial modelling based on two broad alternative assumptions:

- The NSP faces a choice between two equally efficient opex or capex solutions that deliver the same outcomes. In this case, we assume the NSP is responding to a change in output requirements and can implement an opex or capex solution. This solution has a finite duration. At the end of the solution's useful life, the opex allowance is assumed to be adjusted back to the original opex allowance, based on the original level of outputs.
- The AER's approach, where the EBSS and CESS are used to provide time-independent incentives on opex and capex. If opex efficiencies (or inefficiencies) occur in perpetuity and the WACC is 6%, then the incentive strength on opex and capex will be equal. We note that if the opex efficiencies (or inefficiencies) do not occur in perpetuity, the EBSS will reverse any original reward/penalty such that the NSPs should only gain/bear the time value of money.

The findings from this exercise are that:

- Under the first approach our modelling indicates that there is a positive financial incentive for NSPs to prefer capex to opex, if such a trade-off is possible. That is, there is a greater financial return from underspending on capex rather than opex.[76] This incentive diminishes as the assumed life of the asset - and therefore the duration of the opex solution - increases. However, the incentive remains positive for the more common network asset lives of 40 to 50 years.
- Under the second approach, our modelling indicates that achieving capex efficiencies may provide a slightly higher financial return than achieving opex efficiencies (i.e., an incentive to prefer opex rather than capex). This is driven by the different tax treatment of opex and capex.
- Under either approach, an NSP's financial incentive to undertake capex rather than opex is stronger when it is able to outperform the allowed rate of return. In addition, our analysis indicates that when an NSP's actual WACC is lower than the allowed rate of return, its financial incentive to undertake capex is stronger than its financial incentive to undertake opex if the situation was reversed.[77] In other words, the financial incentives when out-/ under-performing the allowed rate of return are asymmetric, and the asymmetry favours capex.
- The DMIS increases the incentive to undertake demand management solutions (potentially opex or capex), but only for certain projects.

In this section, we set out our approach to modelling the financial incentives that NSPs face once they receive their allowances. We do this to test whether the NER and the AER's current approach to applying the rules may create a financial incentive for NSPs to prefer capex over opex.

[76] And overspending on capex rather than opex.

[77] Assuming that the NSP out-/under-performs the allowed rate of return by the same number of basis points.

As set out above, once the NSPs receive their allowances, different incentives will apply. In our modelling we have focused on the financial implications from the CESS and EBSS. We have excluded the DMIS from the modelling, as this needs to be assessed on a project-by-project basis and cannot therefore be modelled quantitatively to determine a general effect on NSP incentives. We note that the AER can choose not to use an EBSS or CESS for individual NSPs (it did not apply an EBSS in the 2015 decisions for ACT and NSW). However, as these incentive mechanisms were designed to help balance financial incentives across capex and opex, and are expected to be used by the AER for most NSPs going forward, we apply both mechanisms in our modelling.

We also exclude the Service Target Performance Incentive Scheme (STPIS). The NSPs' opex and capex allowances are based on the NSPs maintaining their current level of reliability. The STPIS incentivises them to maintain this level (as the NSPs face a penalty if service quality reduces) or rewards the NSPs for improving services, by providing an incentive payment based on the value of customer reliability. As discussed below, our modelling assumes that different options (capex or opex) deliver the same level of reliability; therefore, the STPIS would not impact the results. In practice, if the reliability impact differs between the options that an NSP is considering, then the NSP would need to consider the additional impact of STPIS penalties/ payments.

4.1. Our approach

We have attempted to keep the modelling relatively simple and focus on the NPV difference of the reward/penalty that NSPs receive from out-/ under-performing on capex or opex. As our starting point, we have relied on the AER's January 2015 distribution post-tax revenue model (PTRM) version 3, the AER's November 2013 EBSS and CESS Excel models, and the AER's December 2016 roll forward model (RFM).

We have considered the financial modelling based on two broad alternative assumptions:

- The NSP faces a choice between two equally efficient opex or capex solutions that deliver the same outcomes. In this case we assume the NSP is responding to a change in output requirements and can implement an opex or capex solution. This solution has a finite duration. At the end of the solution's useful life the opex allowance is assumed to be adjusted back to the original opex allowance based on original outputs. In other words, we assume that the EBSS does not apply a second time as the 'base opex' allowance is adjusted for the change in outputs.

- The AER's approach, where the EBSS and CESS are used to provide time-independent incentives on opex and capex. If opex efficiencies (or inefficiencies) occur in perpetuity and the WACC is 6% then the incentive strength on opex and capex will be equal. If the opex efficiencies (or inefficiencies) do not occur in perpetuity the EBSS will reverse any original reward/penalty such that the NSPs should only gain/bear the time value of money (i.e., the WACC in the original saving/overspend).

To model these assumptions, we compare present value (PV) equivalent opex or capex 'solutions'. The solutions are assumed to last for the same period and deliver the same levels of reliability and safety. That is, the opex solution is in place for the length of the alternative capex solution's useful asset life. However, under the second broad assumption outlined above, we assume that opex continues after the end of the solution's life and the EBSS applies again at this point.

Starting scenario

We start from a scenario where:

- We have two hypothetical NSPs, with the same starting expenditure and rate of return allowances, and the same expected actual expenditure. However, when faced with out- or under-performing against their expenditure allowance:
    - one will choose to out-/ under-perform only on opex (OpexNSP); and
    - the other will choose to out-/ under-perform only on capex (CapexNSP).

  If the NSPs' actual expenditure and WACC are the same as the allowed, their NPV of cash flows will be zero.
- We assume that the choice of opex or capex solutions available to the NSPs provide the same outcomes for consumers (i.e., consumers receive the same quality of service from either the capex or opex solution).
- Both companies have a real WACC of 6%. This matches the discount rate used by the AER to calculate the 30% CESS sharing factor, using the EBSS in perpetuity savings. For the base case comparison, the allowed rate of return and actual WACC are assumed to be the same.
- We set the capex and opex solutions to have equivalent PV expenditure for the NSP. For example, if the NSP can underspend on capex by $10m in year 1, we estimate the PV opex based on the asset life and the NSP's actual cost of capital. This means that an opex solution/ underspend is assumed to last the same length of time as the capex solution/ underspend. We use actual WACC rather than allowed rate of return to discount the cash flows.
- There is only a single regulatory period for the NSPs to make a choice, and each subsequent regulatory period reflects the decisions made in the first. Opex in the fourth year sets the opex allowance and actual for each future year (the 'base-step-trend' approach). The cash flows are assumed to last as long as the asset life.
- Under the first broad approach, we assume that the cash flows stop at the end of the solution's life.
- All values are in real terms (this is to simplify the model and does not impact the outcomes).

Our other starting assumptions are set out in ANNEX B.

Metric to measure the relative financial incentive strength from opex or capex out-/ under-performance

To assess the relative NPV gains/losses from out-/ under-performance on opex or capex we have calculated an 'NPV ratio', which is:

$$NPV\ ratio = \frac{NPV\ capex\ out/underperformance}{NPV\ opex\ out/underperformance}$$

If the NPV ratio is below 1.0 then:

- For underspends, reducing opex provides a greater financial return than reducing capex. For example, if the ratio is 0.5 it would mean that reducing opex would provide a financial return twice as much as for reducing capex.
- For overspends, increasing capex is preferred to increasing opex. For example, if the ratio is 0.5 it would mean that increasing capex would cost half as much as increasing opex.

If the NPV ratio is above 1.0 then:

- For underspends, reducing capex provides a greater financial return than reducing opex. For example, if the ratio is 2.0 it would mean that reducing capex would provide a financial return twice as much as reducing opex.
- For overspends, increasing opex is preferred to increasing capex. For example, if the ratio is 2.0 it would mean that increasing opex would cost half as much as increasing capex.

Theoretically, if the incentives between opex and capex are equalised the NPV ratio should be 1.0 if the actual WACC is equal to the allowed rate of return. A ratio below 1.0 supports a financial capex bias, while a ratio above 1.0 supports a financial opex bias.

Model input choices

Our model allows a range of inputs to be varied. The key variables of interest are:

- Asset life. This relates to the capex in the first year and any over-/ under-spend from this.
- Allowed rate of return and actual WACC parameters: gearing, post-tax real return on equity, and pre-tax return on debt.
- The level of capex out-/ under-performance.

4.2. Modelling results[78]

Before looking at the results it is important to note the following:

- Different levels of capex out-/ under-performance do not change the results of the NPV ratio e.g., a $10m outperformance produces the same NPV ratio as a $1m outperformance.
- The NPV ratio is also symmetrical for out-/ under-performance. This is to say that an underspend of $X on capex or opex will generate the same NPV ratio as an overspend of $X on capex or opex.

These factors mean that we do not need to undertake sensitivities around the level or type of out-/ under-performance. However, the reader should bear in mind that large out-/under-performance may not change the NPV ratio but it will change the overall level of cash flows and therefore the magnitude of these changes may influence the NSP's decisions.

DMIS

Because of the project specific nature of the DMIS we have not been able to model this mechanism generically (i.e., to assess the impact across all scenarios and sensitivities). In addition, as the DMIS has not yet been used in practice, we have no 'real world' examples to compare against. For instance, during the stakeholder workshop one participant indicated that they were still unsure whether the AER would provide an uplift in the opex allowance for DMIS projects.

However, the design of the mechanism is to provide a financial incentive to undertake efficient demand management alternatives to traditional network investments. In the case of an opex DM solution that replaces a capex project, our analysis indicates that the DMIS would have the effect of increasing the NPV ratios. That is, we would see a shift upwards of the NPV ratio curve shown in Figure 4.1, shifting the incentives towards opex. While the DMIS will increase the NPV ratios, we cannot say whether this will increase the ratio to, or above, 1.0 at every level of the asset life.

We note that the DMIS is neutral as to whether the DM project is procured from a third-party or implemented in-house. Therefore, capex projects undertaken by NSPs could still be eligible for the DMIS. However, this is subject to the treatment of particular capex projects under other aspects of the regulatory framework. For example, this would need to be consistent with the ring-fencing guidelines and other restrictions, such as limitations on whether behind-the-meter assets can be included in a DNSP's RAB.

---

[78] Please note, the results presented in this final report differ from those presented in our draft report dated 16 April 2018. The changes reflect revisions to the model.

4.2.1. Modelling the decision between equally efficient opex and capex solutions

As noted above, our primary modelling starts from a different assumption than the AER's previous analysis. We assume that the solutions, whether an overspend or underspend, are in response to certain requirements; for example, an unexpected increase in demand that needs to be addressed. We assume that the need can have a limited time requirement and that this is known when the solution is put in place; for example, a specific increase in demand for 10 years or 80 years. Once the solution is no longer required, we assume that the allowances are adjusted to reflect the forecast change in requirements; for example, the opex allowance would reflect a step down in demand.

We believe that this assumption reflects the more micro level decisions that an NSP might make.

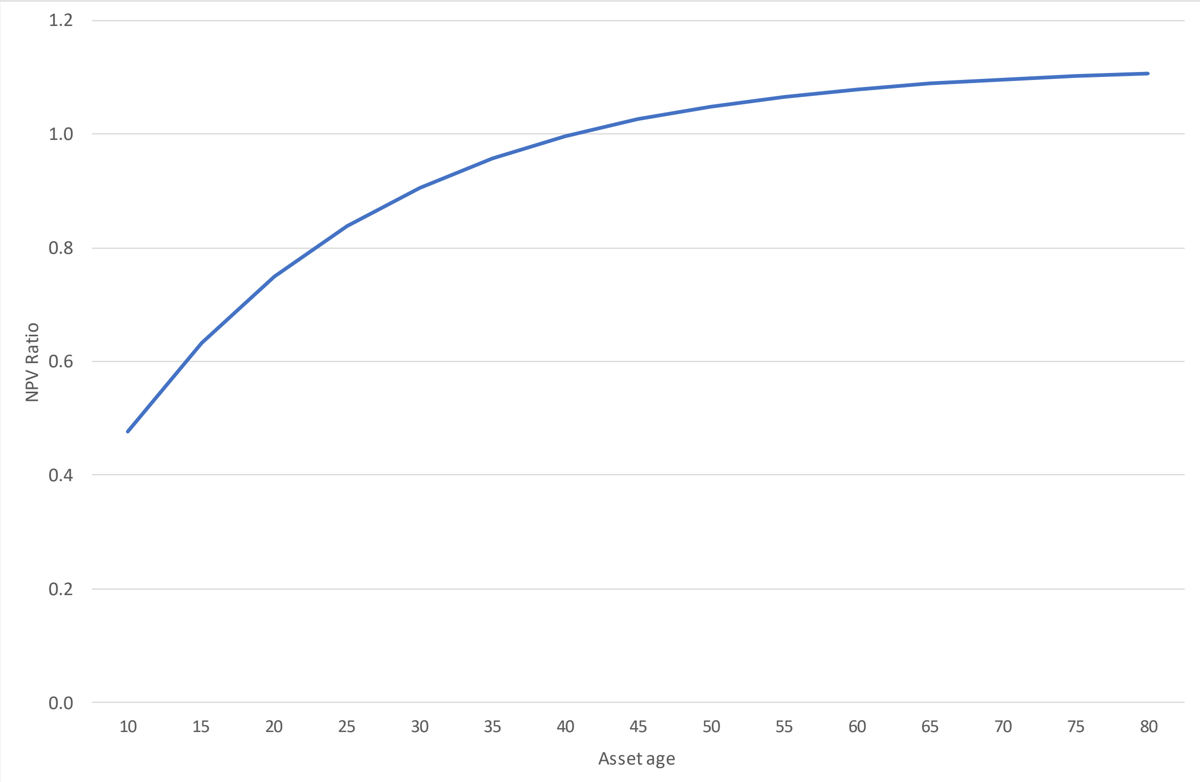
Differences in incentive strength change depending on the expected asset life of the capex solution/ underspend.

From the outset we found that the NPV ratio is highly sensitive to the asset life chosen, and by extension the length of the opex out-/ under-performance to match the capex out-/ under-performance.

The changes in the NPV ratio as the asset life changes are illustrated in Figure 4.1 below. We can see that for very short asset lives (10 years) there is a clear financial benefit from opting to reduce opex rather than capex in the case of outperformance, or to undertake capex rather than opex in the case of an overspend. As the asset life increases the NPV ratio gets closer to one,[79] implying that for long-life capex/ opex solutions the NSPs should be relatively indifferent (for financial reasons) as to the choice of approach. However, this does not take account of the uncertainty that NSPs may face from adopting ongoing opex rather than an upfront capex solution.

[79] The NPV ratio exceeds 1.0 for asset lives of around 40 years (or longer).

Figure 4.1: NPV ratio based on asset life[80]



Source: CEPA

The unbalanced opex/ capex incentives are largely due to how the EBSS and CESS reward the NSPs. The EBSS provides an NSP with a larger upfront savings retention compared to the CESS, if the sharing of savings does not last in perpetuity. To illustrate this in simple terms, $10m in savings divided by 10 years creates a larger annual saving than $10m divided by 30 years. The CESS upfront reward does not change with asset life.

Typical network asset lives for the DNSPs are around 40 to 50 years, for which the NPV ratio is close to or above one. However, for any shorter-lived solutions, such as batteries or third-party services, the ratios indicate a financial benefit to the NSP from undertaking capex (for an overspend) or reducing opex (for an underspend).

Below we provide a series of examples to explore what the NPV ratio means in practice. It is important to bear in mind that these are simplified examples that do not allow for *ex post* or other adjustments to future allowances that the AER may make to ensure the incentives work as intended.

Example 1: Under-performance (overspend)

This example starts from a base case where both NSPs have a capex allowance of $100m, an expected asset useful life of 40 years, and a 6% allowed rate of return. If we assume that the NSPs' actual expenditure and WACC are in line with allowances then their NPV will be zero.

[80] The NPV ratio is the Capex under/overspend NPV divided by the opex under/overspend NPV.

In the first year of the regulatory period, there is a change in requirements that means the NSPs must overspend against their allowance.

The CapexNSP identifies a capex solution that will cost $10m in the first year of the regulatory period (i.e., spending $110m on capex in total). After the incentive mechanisms are taken into account (i.e., the NSP bears 30% of the overspend), the CapexNSP's NPV loss from overspending on capex is $2.3m.

The OpexNSP identifies an alternative solution that provides the same outcomes but by using opex. The cost of this opex solution is the same as the CapexNSP's solution in PV terms; in this case, it leads to an increase in opex of $0.7m per annum over the next 40 years. After the incentive mechanisms are taken into account (i.e., the NSP bears the $0.7m overspend for six years), the OpexNSP's NPV loss from overspending on opex is $2.3m.

Dividing the CapexNSP's change in NPV by the OpexNSP's change in NPV results in an NPV ratio of 1.0. There is little difference between the financial loss from choosing an opex solution over a capex solution.

Example 2: Outperformance (underspend)

This example starts from a base case where both NSPs have a capex allowance of $50m, an expected asset useful life of 30 years, and a 6% allowed rate of return. If we assume that the NSPs' actual expenditure and WACC are in line with allowances then their NPV will be zero.

In the first year of the regulatory period, the NSPs identify efficiency gains that can be made.

The CapexNSP identifies capex savings of $5m in the first year of the regulatory period (i.e., spending $45m on capex in total). After the incentive mechanisms are taken into account (i.e., the NSP retains 30% of the underspend), the CapexNSP's NPV gain from underspending on capex is $1.1m.

The Opex NSP identifies an alternative solution that provides the same outcomes but reducing opex instead. The opex savings are the same as the CapexNSP's savings in PV terms; in this case it leads to a reduction in opex of $0.4m per annum over the next 30 years. After the incentive mechanisms are taken into account (i.e., the NSP retains the $0.4m underspend for six years), the OpexNSP's NPV gain from outperforming its allowance is $1.3m.

Dividing the CapexNSP's change in NPV by the OpexNSP's change in NPV results in an NPV ratio of 0.83. This means that the OpexNSP is around 10% better-off than the CapexNSP. Therefore, the capex solution would have to be more efficient than the opex solution for a 'neutral' NSP to adopt it; there is a financial bias towards undertaking capex rather than opex.

Example 3: Short-life network solution versus services purchased from third parties

The example considers the implementation of a 'short-lived' capex or opex solution; for example, the use of a battery or demand management to deal with an increase in demand on a feeder.

Let us assume that the capex solution – installing a battery – costs $5m and has a 10-year asset life. The opex solution – purchasing demand response from third parties – has an expected cost of $0.7m per annum for 10 years (PV equivalent to the 10-year battery cost). The reliability and safety to consumers from either solution is the same.

The increase in demand was unexpected and therefore no allowance was made by either the CapexNSP or the OpexNSP. The expenditure is not required for a reliability corrective action.

The NPV loss of implementing the capex solution for the CapexNSP is $1.1m, while the NPV loss of implementing the opex solution for the OpexNSP is $2.3m. The NPV ratio is therefore slightly below 0.5. This means that by investing in a battery, the CapexNSP will bear less than half the loss of the OpexNSP who has instead purchased demand management services from third parties.

While we have not explicitly modelled the DMIS, we understand from AER (2017c) that the NSP will receive an incentive payment equal to 50% of the PV of the expected opex solution costs, in this case $2.5m.[81] Taking this into account, the OpexNSP would receive a total NPV gain of $0.2m from purchasing services from third parties.

While the DMIS offsets the financial capex bias in this example,[82] this requires additional payments from consumers.[83] We understand that if the expenditure was required for a reliability corrective action, the incentive payment would be assessed against the option with the second highest net benefit.[84] In this case, as the two options (capex or opex) have the same net benefit the DMIS payment would be zero.

How does the NPV ratio change if the allowed rate of return and actual WACC is higher/ lower?

We tested how sensitive the NPV ratio is to different WACCs. We have calculated the NPV ratio using a 5% rate of return and a 7% rate of return, while still assuming that the actual WACC is equal to the allowed rate of return. The results are shown in Figure 4.2.

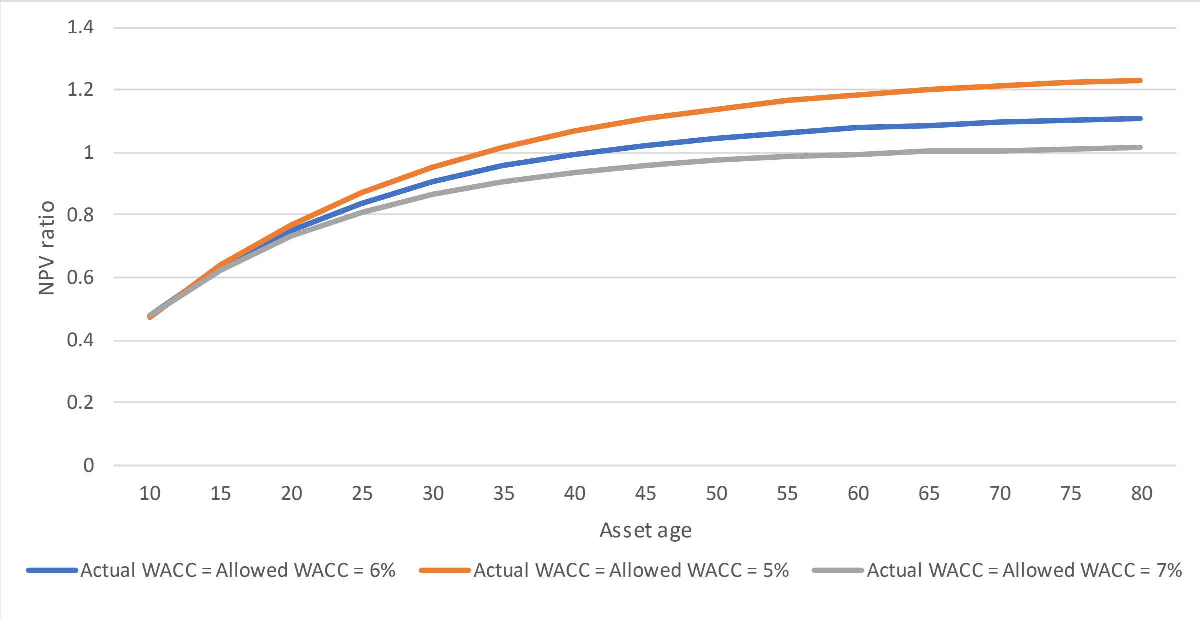
[81] We understand that the DMIS payment would be the lower of the NPV benefit of the DM solution or 50% of the NPV cost of the solution. We assume that in this case, the NPV benefit of 'solving' the issue is greater than the NPV cost; therefore the incentive payment is 50% of the total cost, as the lower value.

[82] We cannot estimate the NPV ratio as we now have a negative numerator and a positive denominator.

[83] This finding is supported by the AER's example B.1 in Annex B of AER (2017c).

[84] AER (2017c), page 41.

Figure 4.2: NPV ratio based on asset life and differing allowed rate of return and actual WACCs



Source: CEPA

A lower WACC increases the NPV ratio, while a higher WACC decreases it. The reason for this is that changing the WACC has a smaller impact on the CapexNSP's NPV than on the OpexNSP's NPV.

This result fits with our *a priori* expectations that a discount rate lower than 6% would decrease the capex bias. This is because the 30% sharing factor estimated for the EBSS is based on a 6% discount rate, used to estimate the share of opex savings in perpetuity. If the discount rate is lower, the sharing factor decreases (approximately 25% with a real discount rate of 5%). Therefore, if considering the benefits to NSPs from longer lived solutions, they retain more of the benefits from the 30% *ex ante* capex sharing factor compared to a 25% in perpetuity opex sharing factor.

This is an important point as the WACC (discount rate) does change over time, and there is no guarantee that it will be 6% real at each determination.

What happens to the incentive strength if the NSP's actual WACC is different from the allowed rate of return?

We estimate two sensitivities:

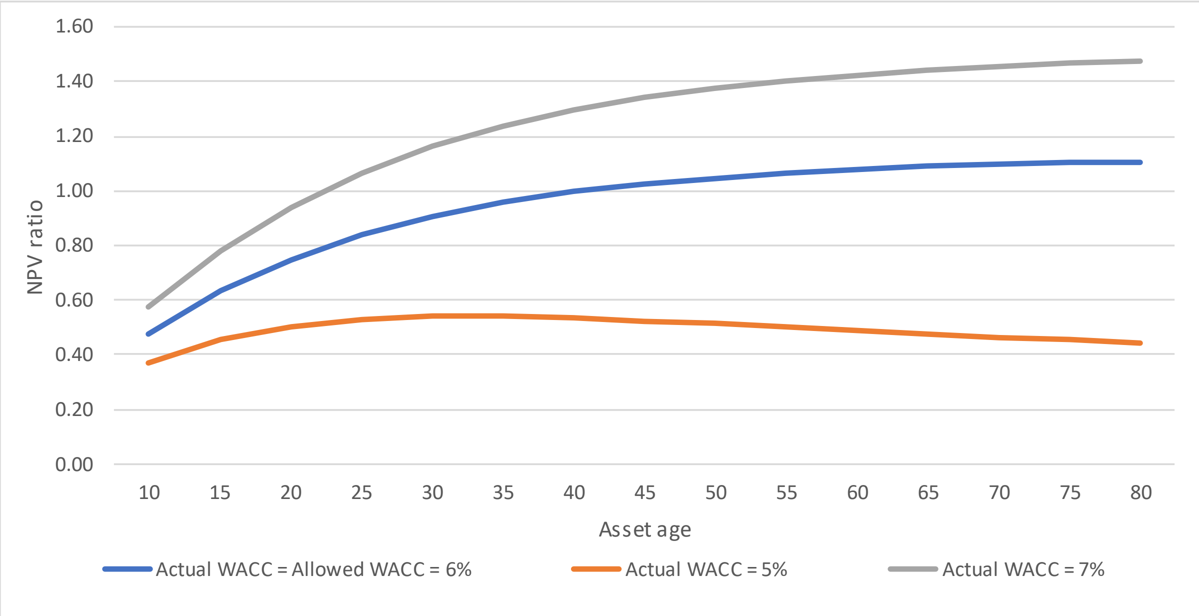
- Actual WACC is lower than the allowed rate of return, 5% rather than 6%.
- Actual WACC is higher than the allowed rate of return, 7% rather than 6%.

There are now two effects being modelled – WACC out-/ under-performance and expenditure out-/ under-performance. Therefore, we have estimated the NPV benefit/loss from the WACC being lower/higher than the allowed rate of return and subtracted this from the NPV benefit/loss from an expenditure out-/ under-performance.

The outcome here is expected – an actual WACC lower than allowed rate of return increases the capex bias, while a higher actual WACC decreases it. However, an interesting result occurs when the actual WACC is lower than the allowed rate of return and the asset life is increased. As illustrated in Figure 4.3, at first, we see an increase in the NPV ratio, but as the asset life increases the NPV ratio begins to decrease. This means that as the asset life increases the capex bias also increases.

This is because as the asset life increases, the NPV benefit from the actual WACC being lower than the allowed rate of return increases at a faster rate, compared to the NPV benefits/ losses from out-/ under-performance.

Figure 4.3: NPV ratio based on asset life and actual WACC differing from the allowed rate of return



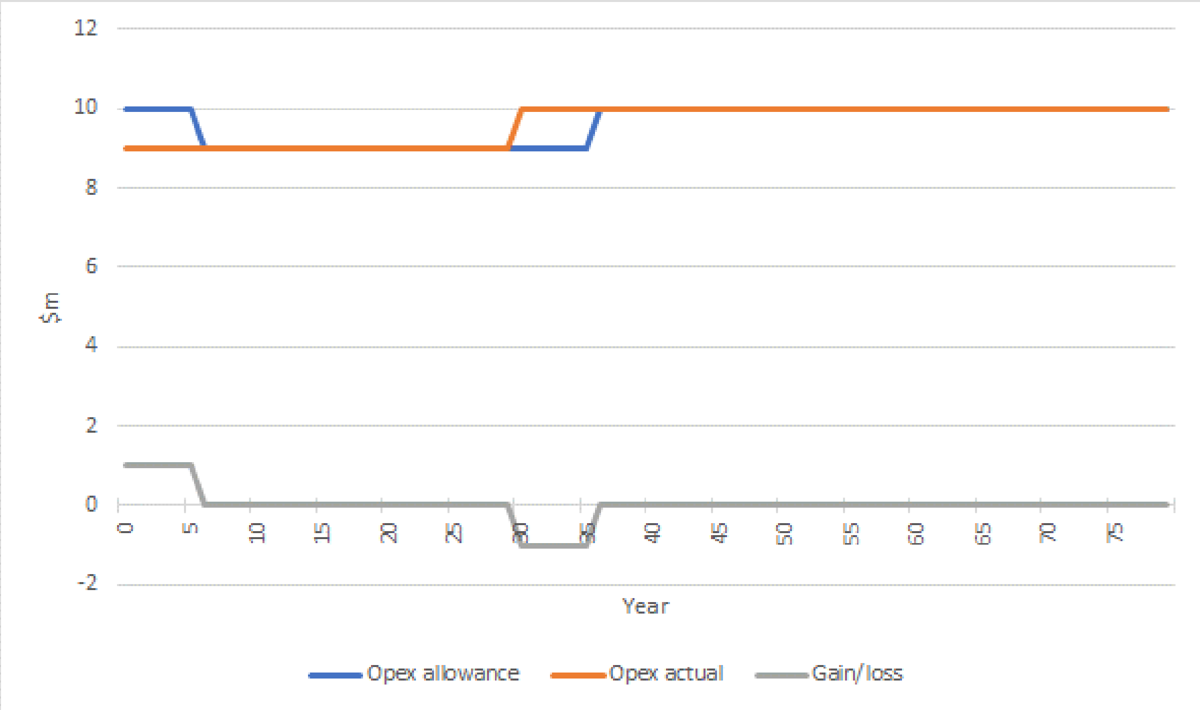
Source: CEPA

As with the base scenario, the NPV ratio does not change based on the size of expenditure out-/ under-performance once the WACC out-/ under-performance is adjusted for.

4.2.2. Financial incentives under the assumption of indefinite opex

Our modelling above assumes that the cash flows end when the solution ends. Alternatively, we could assume that the opex cash flows will continue. In this case, the reward/penalty from the EBSS will reverse after the 'solution' ends, and the NSP will only retain/bear the time-value of the under/overspend. We illustrate this in Figure 4.4. In this example, we have an opex underspend in the first year of the first regulatory control period and the opex underspend (of $1m per annum) is assumed to last for 30 years. The NSP gains the underspend benefit for six years, but after 30 years it bears the six years of overspending against its allowance, after the life of the underspend ends.

Figure 4.4: The EBSS with a perpetual allowance



Source: CEPA

The NSP gains the financing benefits from the early underspend until the 'solution' ends. If the WACC is assumed to be 6% real then the benefits are around 30% of the underspend (as per the AER's in perpetuity calculation). As the capex asset life is assumed to have ended at 30 years and not replaced, the CESS impact does not change.

This assumption is in line with the AER's position of in perpetuity opex savings matching the capex *ex ante* sharing factor. This assumption reflects the AER's top-down approach to setting the opex allowance. We also understand that modelling undertaken for the COAG Energy Council by KPMG follows these assumptions.[85] KPMG's analysis indicated that if the discount rate was greater than 6%,[86] an NSP had an incentive to choose an *"inefficient capex option for certain opex amounts"*.[87] KPMG did not elaborate on how it chose the *"certain opex amounts"*.

The NPV ratio is closer to one, but there may be a slightly higher financial incentive to make opex efficiency savings compared to capex.

The alternative assumption gives a different NPV ratio profile. This is illustrated in Figure 4.5. Here we find that the NPV ratio is consistently above 1.0, i.e., that the imbalance between the incentive strength has now switched to favouring opex over capex. This imbalance is due

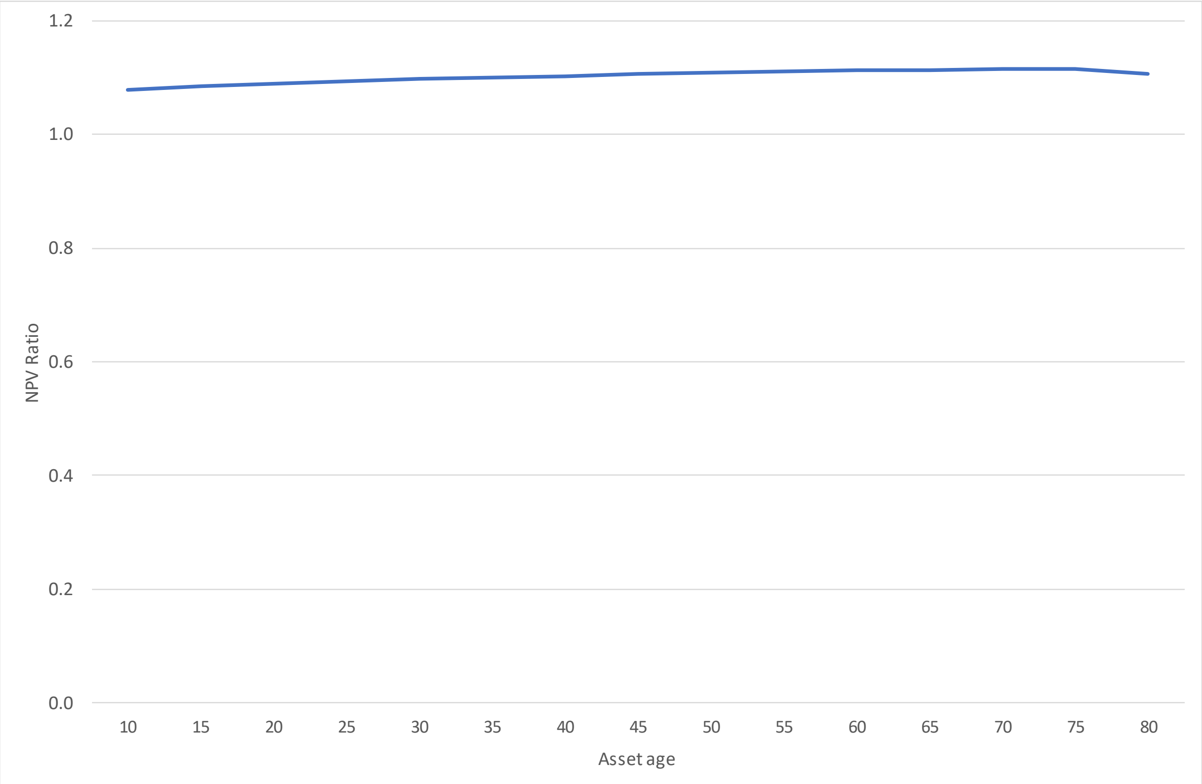
[85] KPMG (2018). Published by the CAOG Energy Council on 18 April 2018.

[86] We assume that KPMG are referring to the allowed rate of return and that the actual WACC is equal to the allowed.

[87] KPMG (2018), page 73.

to the different tax implications for capex and opex. On a pre-tax basis the NPV ratio would be one, in line with the AER's modelling.

Figure 4.5: NPV alternative assumption



Source: CEPA

Under this alternative assumption, what happens to the incentive strength if the NSP's actual WACC is different from the allowed rate of return?

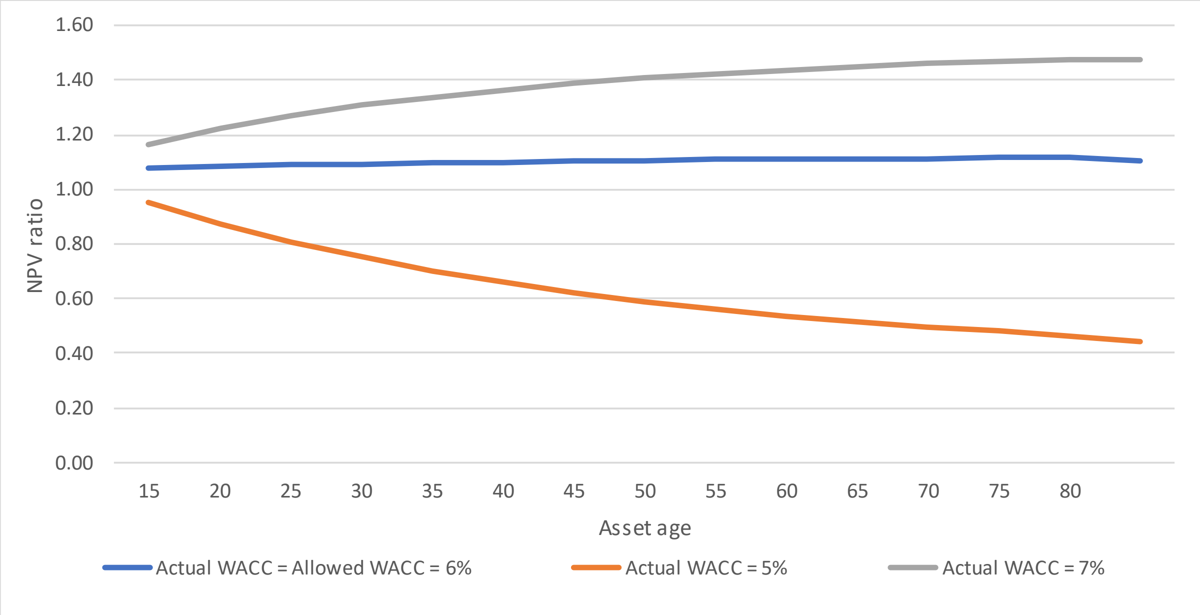
We estimate two sensitivities:

- Actual WACC is lower than the allowed rate of return, 5% rather than 6%.
- Actual WACC is higher than the allowed rate of return, 7% rather than 6%.

There are now two effects being modelled – WACC out-/ under-performance and expenditure out-/ under-performance. Therefore, we have estimated the NPV benefit/loss from the WACC being lower/higher than the allowed rate of return and subtracted this from the NPV benefit/loss from an expenditure out-/ under-performance.

The outcome here is expected – an actual WACC lower than the allowed rate of return creates a financial capex bias, while a higher actual WACC creates a financial opex bias. This is illustrated in Figure 4.6, where we can see that the NPV ratio for an actual WACC of 5% is significantly below that of the base case of (6% allowed rate of return and actual WACC), while the 7% actual WACC scenario provides NPV ratios well above the base case.

Figure 4.6: NPV ratio based alternative assumption, asset life and actual WACC differing from the allowed rate of return



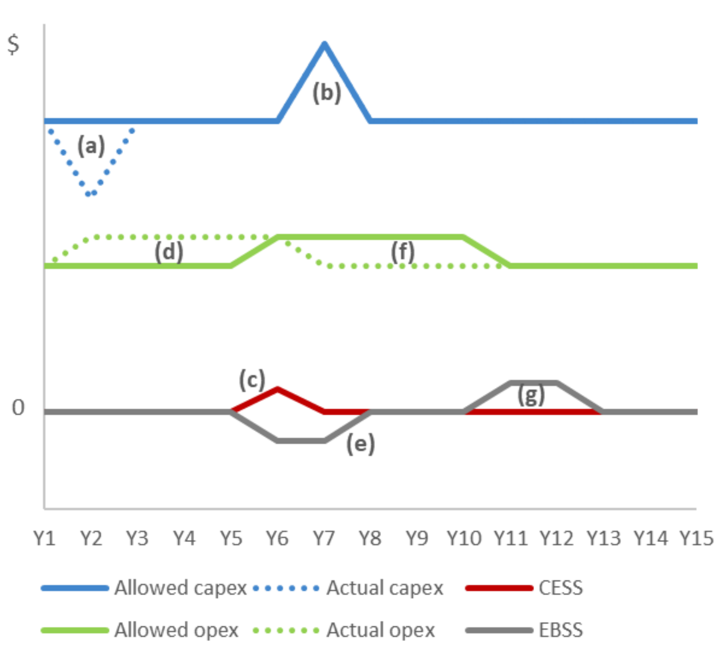
Source: CEPA

4.3. Deferrals

The examples outlined above describe circumstances in which NSPs may be deciding between equivalent capex or opex solutions. However, it may be equally (or potentially more) likely that NSPs will be able to deploy opex solutions to defer, rather than replace, capital investments (at least in the near future while longer-term opex solution are developed). The question is then whether the current framework incentivises efficient capex deferrals, where opex (for example for DM) may be required to enable the deferral. Again, this depends on the interaction between the EBSS, CESS and DMIS (if applicable). AER (2013a) provides examples where capex is deferred without any additional opex.

We illustrate the effects of a deferral through a stylised example, shown in Figure 4.7 below.

Figure 4.7: Stylised capex deferral



NSP defers capex from Y2 **(a)** to Y7 **(b)**, and receives an CESS payment **(c)**.

To achieve the deferral, the NSP overspends its opex allowance over Y2 to Y5 **(d)**. Under the EBSS carryover mechanism, the NSP bears the overspend for 6 years in total **(e)**.

The NSP's allowance for Y6 to Y10 is adjusted upwards to reflect the overspend. Once the NSP undertakes the deferred capex project, the additional opex is no longer required, and they underspend against their opex allowance over Y7 to Y10 **(f)**. Under the EBSS, the NSP retains the benefit of the underspend for 6 years in total **(g)**.

Source: CEPA

From the NSP's perspective, if they incur a *temporary* opex overspend in order to defer capex, in net terms they will only bear the time value of money impact of that overspend. This is reflected by the combined NPV impact of **(d), (e), (f)** and **(g)**. Overall, the NSP should have a financial incentive to implement deferrals, so long as the time value of money impact of the opex overspend is less than the CESS reward (represented by **(c)**), which is 30% of the value of **(a)**.

From the perspective of consumers, a capex deferral will be efficient if the net benefit of the deferral is greater than the net opex to achieve it, in PV terms. As noted in Section 2.2.2, deferrals may result in consumers paying the CESS reward, but, where there is an increase in an NSP's forecast capex for future regulatory periods, also funding the capex in the following period. To mitigate this, the AER can adjust CESS payments for <u>material</u> capex deferrals, such that the NSP only retains 30% of the *benefit* of the deferral. The benefit is calculated as the difference between the NPV of the underspend and the NPV of any marginal increase in capex in a later period that results from the deferral (i.e., the NPV difference between **(a)** and **(b)** in Figure 4.7 above).[88] We understand that the AER does not take account of the time value of money for opex required to achieve the deferral when it calculates an adjustment. This means that, when an adjustment for material deferrals is made, the NSP's share is likely to be below 30% across capex and opex.

At present, materiality is defined qualitatively, allowing the AER to make an adjustment in cases where:

[88] AER (2013a), page 42.

- the amount of deferred capex in the current regulatory period is material;
- the amount of estimated underspend in capex in the current regulatory period is material; and
- the total approved forecast capex in the next regulatory period is materially higher than it is likely to have been without the current period deferral.

Overall, an NSP's incentive to undertake an efficient capex deferral is subject to a range of financial and non-financial factors, including:

- The relative size of the opex overspend compared to the capex deferral and the NSP's actual WACC.
- How materiality is defined for the purpose of the CESS, and how easily the AER can identify deferrals. This is likely to become clearer with further experience in the application of the CESS.
- The impact of the DMIS, as a DM solution could be used to defer a capex project and therefore be eligible for an incentive payment under that scheme. This would appear to increase the incentive to undertake capex deferrals.[89]
- The NSP's view on the likelihood of the deferred capex being approved at the next price determination.
- The implications of any deferral for reliability standards, and associated penalties and/or reputational impacts if these are not met, including incentives under the STPIS mechanism.
- The other incentives referred to in Section 5.

4.4. Summary

Our analysis indicates that the financial incentives on NSPs can vary based on their individual circumstances and assumptions.

If we assume that the NSPs face a choice between equally efficient opex or capex solutions, and future allowances reflect changes in outputs, then there is a financial incentive for NSPs to prefer capex to opex if asset lives are less than 40 years. However, as the life of the asset increases, the financial incentive is to prefer opex. This unequal incentive exists even if the actual WACC is equal to the allowed rate of return; even if the actual WACC is higher than the allowed rate of return, there is still an incentive in favour of capex where the asset has a relatively short expected useful life.

Alternatively, if we start from the assumption that the EBSS 'reverses' any reward/penalty if the solution does not last in perpetuity (and allowances reflect past expenditure levels rather

[89] Subject to the AER's application of the DMIS in practice. We note that DM projects may also be capex (rather than opex).

than forecast output levels), then there is a financial incentive to achieve capex rather than opex savings (or overspend on opex, rather than capex), although this results from differences in tax implications.

Either of the approaches for assessing financial incentive strength may be appropriate, depending on the NSP's circumstances. This analysis highlights that, at least on a post-tax basis (which is how the NSPs are likely assess the benefits/costs), the incentives are not equal. We note that the AER's implementation of the CESS to match the EBSS was intended to "achieve better balance"[90] between the opex and capex incentives, rather than necessarily equalise them. The introduction of the CESS does help to reduce the imbalance between the expenditure approaches. On a pre-tax basis, and assuming in perpetuity opex savings/ overspends, the incentives are equalised.

The DMIS is intended to shift NSPs towards adopting efficient demand management solutions by providing NSPs with a financial reward for adopting eligible DM projects. The DMIS appears to be more focused around the deferral of traditional capex projects, rather than longer-term solutions.

It is important to note that we are assuming that the capex and opex solutions are substitutable. In practice, at present this may be a relatively small proportion of total expenditure. However, as we noted in Section 1, with the changing nature of the electricity sector the scope for trade-offs may increase in future. We see the potential for this trade-off to encompass longer-term opex solutions (for example, long-term contracts with third-party service providers).

Our assessment of the current incentive arrangements in Section 2 highlights that the interactions between the incentives are complex and vary depending on the projects and/or issues the NSPs are reviewing.

Given the differences in how opex and capex are remunerated, achieving a balance of incentives between these expenditure types while still using separate mechanisms would be complex. For example, the EBSS sharing factor is determined based on a fixed 6% discount rate, the CESS sharing factor is based on the NSP's allowed rate of return, and the assessment of the RITs (and therefore DMIS) uses the regulated cost of capital as the lower bound, but with flexibility for this to vary depending on the level of risk for the project.[91] Therefore, the relative sharing factors and incentive strengths will change over time as the allowed (and actual) rate of return changes.[92] In addition, separate mechanisms are unlikely to address other factors (discussed in the following section) that may create a capex bias.

[90] AER (2013a), page 12.

[91] AER (2017a), page 20.

[92] Other jurisdictions and regulators, particularly Ofwat, used a combination of mechanisms like the EBSS and CESS to better balance financial incentives over time and between opex and capex. However, like Ofgem, Ofwat moved to a totex incentive mechanism as it was concerned that the combination of financial incentives did not provide the balance sought. The totex incentive mechanism allowed for the same *ex ante* sharing factor to apply

5. OTHER INCENTIVES

In addition to the regulatory incentive schemes outlined above, there are several other factors that may influence NSP decision making. The key issues that we identify in this section are:

- A perception that companies prefer to 'grow the RAB', to increase overall earnings and maintain long-term, stable shareholder returns.
- Risk aversion, that could result in a preference for deploying more commonly used capex approaches instead of adopting alternative solutions. This could be due to concerns about the ability to maintain service standards (avoid penalties) or uncertainty around the ongoing expected cost of alternative solutions.
- Reputational incentives. This could include avoiding solutions which may not be 'tried and tested', or concerns about public and investor perceptions if the company appears more inefficient than its peers due to its approach.
- Existing cultural biases that favour a 'poles and wires' solution over alternative solutions, resulting from an NSP's history, skill base and ownership/organisational structure.

On the surface, these factors lean toward promoting a capex bias. However, while it is plausible that these factors could influence capex/opex trade-offs, this is based on relatively subjective judgements.

The preceding sections have assessed the strength of the financial incentives built in to the regulatory framework, both pre-allowance determination (expenditure assessment) and post-allowance determination (incentive schemes). In this section, we consider more qualitative evidence on other incentives that could also influence NSP decisions on opex and capex trade-offs. Drawing on previous investigations into the existence of a capex bias, Table 5.1 below presents a summary of potentially relevant factors.

Table 5.1: Other potential contributors to a capex bias

Factor	Description
Focus on RAB growth	It has been suggested that NSPs (or their shareholders) may operate within a corporate culture that is focussed on growing the RAB, which drives growth in earnings and provides investors with long-term, stable revenue streams. In Section 5.1 we draw on a review of selected analyst reports covering listed NSPs (both in Australia and elsewhere), to consider whether these support this proposition.
Risk aversion	While diversification may balance exposure to business-specific (non-systematic) risks across a portfolio, management of these risks is nonetheless an important consideration for investors. As a result, investors may encourage management to avoid solutions that are higher risk (or at least perceived as such). To the extent that opex solutions are perceived as higher risk than capex solutions, this could influence NSP decisions on whether to undertake opex or capex solutions. We explore this further in Section 5.2.

to both 'opex' and 'capex' as the regulator capitalises a certain proportion of all expenditure and the appropriate amount of total under/overspend. The New York PSC also considered the use of totex, however the PSC ruled it out, at least for now, due to complications with the accounting standards used in the US.

Factor	Description
Reputational incentives	Reputational incentives could come into capex/opex trade-offs in several ways: • As noted above, if there is uncertainty over the operational performance of opex solutions. • A desire to perform well against peers in benchmarking assessments, contributing to a focus on achieving opex efficiencies. Beyond the financial incentives, there may be significant reputational effects from being perceived as an efficient or inefficient network.
NSP culture and skills	Other ways in which corporate culture may influence NSPs' decisions include state or private ownership, the preferences and professional backgrounds (e.g. engineering) of asset managers, organisational structures that separate opex and capex decision-making, and NSP familiarity with or understanding of non-capex options.

Source: CEPA, Ofwat (2011), Frontier Economics (2017).

In the following sections, we focus on the first two sets of factors – RAB (earnings) growth and perceptions of the impact of opex on business risk. It is important to note that this analysis considers evidence for the *presence* of these perceptions, rather than whether they are correct or not. We note Ofwat's 2011 conclusion that the wide-spread perception of a capex bias in the UK water sector was a self-fulling belief.

The latter two factors – reputational incentives and NSP culture and skills - are highly qualitative in nature. Therefore, we are unable to provide a robust view on the weight that NSPs might place on reputational factors, or how their internal culture, management process and skill base will affect expenditure decisions.

The key reputational considerations for an NSP are likely to centre on:

- Providing the distribution standard network services and prescribed transmission services in a reliable and safe way.[93]
- Being identified as providing efficient delivery of these services.

Anecdotal evidence, such as statements in regulatory submissions and annual reports, indicates that management, at least, may place quite a high weight on these issues.

Ownership structure can affect the decision-making process. State-owned management may have objectives that differ to management of privately-owned utilities; for example, a lesser focus on achieving profits under the incentive framework, with other considerations taking a greater role. A number of Australian commentators, including the AEMC, have noted that government-owned corporations may not have achieved the same level of efficiency as privately-owned companies, although both face the same incentive regime under a CPI-X regulatory design.[94] In addition, and related to the reputational factor, state-owned

[93] There is a financial incentive (STPIS) associated with this as well.
[94] See for example, AEMC (2012b), AER (2015a) and Wood et al (2018).

enterprises may seek to avoid being seen as materially outperforming allowances, as this could indicate that they had over-forecast and therefore charged their customers too much.

5.1. Focus on RAB growth

It has been proposed that investor preferences for RAB growth (or at least maintenance), as well as a focus on the RAB as a key metric, could also be a factor in NSP decisions on whether to undertake opex or capex.[95] As discussed in Section 1.4, regulators and other commentators have suggested that NSPs may be focussed on growing their RAB because it allows them to 'earn a return', while opex solutions do not, and this return is stable over the long-term.

While a higher RAB would increase an NSP's absolute profit (other factors held equal), the scope to earn a return above the investors' opportunity cost of capital does not depend on growing the RAB *per se*. Rather, this depends on whether an NSP's actual WACC is below their regulatory allowance. RAB growth must be financed, and new equity investment is required to maintain an equity to RAB ratio. Overall, this suggests that a preference for growing the RAB (rather than adopting opex solutions with similar or lower expected PV costs) should hold only when the NSP is able to outperform the allowed rate of return.

As noted in Section 1.4, while at odds with economic theory, a preference for RAB growth *could* still exist in the absence of scope for WACC outperformance, due to a number of other factors, including investors seeking long-term stable cash flows, risk aversion (see Section 5.2) or other behavioural/cultural factors that emphasise the RAB. To assess the plausibility of the latter point being a contributing factor, we have reviewed a selection of analyst reports, to investigate whether their coverage of listed electricity networks generally supports this proposition.

A sample of analyst commentary is presented in Table 5.2 below. While these reports indicate the value that a selection of analysts place on RAB growth, they clearly do not form a comprehensive picture of the market's view of the assets. Nevertheless, they are consistent with our understanding of investor views, both in listed and unlisted markets.

Table 5.2: Focus on the RAB - extracts from investment analyst coverage of energy networks

Analyst/Company	Commentary
Australian energy networks	
Credit Suisse, on Spark Infrastructure	"The [2015 – 2020 regulatory] proposal put forward by SAPN calls for a 50% increase in capex allowance versus the previous regulatory period ... Capex is important as it determines the ability to grow earnings and dividends over time."[96]
Morgans, on Spark Infrastructure	"A key feature of the [AER's draft decision] was a substantially lower capex allowance across the five years (~$1.1bn) than proposed by Transgrid (~$1.8bn). Holding all else constant, this results in higher free cashflow

[95] See for example, Ofwat (2011), AEC (2017).

[96] Credit Suisse (2014), page 3.

Analyst/Company	Commentary
	during the regulatory cycle, but reduces long-term growth in the Regulated Asset Base (and thus long-term revenues and value). However, this capex allowance does not include potentially substantial capex from contingent projects which if triggered will enhance RAB and earnings growth."[97] "We estimate across SKI's three asset companies the return on and return of capital contributes about 60% of revenues. This approach means that the Regulated Asset Base anchors long-term revenues and value."[98]
Morgans, on SP AusNet	"Under the regulatory regime, the [RAB] is a key anchor of revenues and value. All capex deemed efficient and prudent by the AER is rolled into the RAB, providing SPN with surety of a return on and of the capex over the life of the asset."[99]
Macquarie on DUET	"… RAB is not growing, thus making it very difficult for DUE to deliver materially more than inflationary RAB growth across the DUE group." "DUE has limited RAB growth and faces the pressure of regulatory resets in 34% of its asset in CY16 which will ultimately influence its ability to maintain or grow its dividend".[100]
International energy networks	
Credit Suisse, on National Grid UK	"[A]sset base growth underpins the business model" and that National Grid "think that RAB growth and low interest rates can help the shares provide ongoing returns of c8-10%".[101] "Capex and RAB growth is the most important part of NG's bottom-up investment case. .... RAB growth is now the key lever NG has left to grow and try to deliver returns and reach the company's c8-10% p.a. total return objective. … The stock trades on a high premium partly because it has growth, and it has growth because it trades on such a high premium and can get the value creation. The possibility for this circularity turning from a virtuous circle into a vicious circle if capex falls is why we are so concerned about this."[102]
Macquarie, on National Grid UK/US	"National Grid is a highly defensive utility that has benefited from the low interest rate environment, has high returns, unprecedented clarity to beyond 2020, a growing RAB business (particularly in the US), and a strong dividend policy."[103]
Berenberg, on National Grid UK	"More capex is good (it drives RAB growth) as long as it is not too concentrated, putting strains on the balance sheet. For this reason, a sharp

97 Morgans (2017), page 1.
98 Ibid, page 4.
99 RBS Morgans (2013), page 10.
100 Macquarie (2015a), page 1.
101 Credit Suisse (2016a), page 4.
102 Credit Suisse (2016b), page 6.
103 Macquarie (2016), page 41.

Analyst/Company	Commentary
	reversal of the hiatus in UK generation investment and tightening reserve margin remains a risk."[104]
Macquarie, on European energy networks	"In our scoring system we have added a 10% discount to transmission RAB in order to highlight the detrimental use of transmission assets and the subsequent effects on capex, and a 10% premium to power distribution RAB in order to reflect the future opportunity of higher capex in this area and subsequent higher premium to RAB."[105]

While the scope for WACC outperformance is clearly a significant factor in their analysis, the selection of extracts presented above also appears to be consistent with a view that RAB growth is a *generally* desirable outcome in investors' consideration of regulated businesses. We would expect that investors would provide incentives (e.g., bonuses) for management to deliver outcomes aligned with their preferences.

In this context, it is plausible that under the current regulatory framework, a primarily opex-focussed business may not be equally preferred by the current investors in regulated infrastructure assets. If there is a change in operations to favour more opex-based approaches, while overall investment needs might decrease, they may also change. Rather than investors' equity being used for capex (and therefore backed by the RAB), it may instead be needed as working capital to cover the liabilities created from the adoption of opex-based solutions. There are two probable key changes that occur in this scenario:

- **The NSPs' operational leverage decreases.** That is, the NSPs' fixed costs decrease as a proportion of their total costs.
- **Uncertainty over the NSPs' liabilities increases.** As illustrated in Section 2.1.1 and discussed in the following section, NSPs would be more exposed to longer-term cost uncertainty.

The investors that were previously happy to invest in the NSPs when their equity was backed by the RAB may not be so inclined to provide working capital, nor accept the level of risk associated with opex-based solutions, unless reflected appropriately in the regulatory framework. In the extreme - and unlikely - event that NSPs become 'asset light', a margin on all their opex may be required to reflect working capital requirements and risk.[106]

In summary, the anecdotal evidence available indicates that investors are comfortable with the long-term stable returns associated with a RAB-based approach under the current regulatory framework. This perception may discourage NSPs from adopting more opex-based solutions as they may diminish the stability (or growth) of the RAB, without any increase in the return on equity.

[104] Berenberg (2017), page 2.
[105] Macquarie (2015b), page 16.
[106] It is important to note that simply increasing the allowed rate of return will not result in a shift to opex approaches and indeed the existing issues would be exacerbated by this approach.

5.2. Opex and business risk

As discussed in Section 2.1.1, while diversification may balance business-specific (non-systematic) risks across a portfolio, management of these risks is nonetheless an important consideration for investors. As a result, investors may encourage management to avoid solutions that are higher risk (or at least perceived as such).

To the extent that opex solutions are perceived as "higher risk" than capex solutions, this could influence NSP decisions on whether to undertake opex or capex solutions. Potential reasons why opex solutions could be viewed as higher risk include:[107]

- If the opex solution involves an ongoing contractual relationship with a third-party:
    - Transaction costs associated with finding third-party providers and establishing a contract.
    - Risks associated with managing this relationship (compared to a solution provided in-house), for example managing disputes, performance, or insolvency.
    - Compared to an in-house opex or capex solution, loss of control of the assets providing the service, with associated concerns as to whether the solution will perform as required, when required.
- Uncertainty around how long-term contracts for services would be treated within the regulatory cost assessment process if the contract term extended beyond one regulatory period.
- Relative to an upfront capital investment, an ongoing opex solution may have more cost uncertainty, due to fluctuations in input costs over time.
- In relation to opex solutions that are innovative, uncertainty over the expected technical performance of the solution.

In support of the above, in its response to the stakeholder workshop, ElectraNet submitted that the "*cost recovery arrangements leave TNSPs in a position whereby, at best, the incurred service costs of contracted non-network services are fully recovered, often in arrears. However, unlike capital expenditure which attracts a risk based return on investment, these arrangements deliver no commercial upside and bring considerable potential downside through potential cost recovery risk, cash flow risk, contractual risk and compliance risk, recognising that the TNSP retains service delivery accountability whereas contractual arrangements can never perfectly contract - and nor are counterparties willing to accept - this risk in full.*" This statement expresses at least one TNSP's views on the risks associated with

[107] Drawn in part from Ofwat's investigation into a capex bias in the UK water sector.

non-network solutions and highlights a corporate view that the WACC provides a risk-based return.[108]

We note that in responding to several recent rule changes, NSPs have highlighted risks that could be associated with opex solutions, including solutions procured from third parties. For example, in relation to the draft contestability of energy services rule determination, Endeavour Energy observed that: *"If a network "bias" exists, it may be more attributable to the immaturity and high cost of alternative, non-network technologies or the intrinsic inefficiency of decentralised, distributed solutions"*.[109]

Commenting on the same draft determination, SAPN, CitiPower and Powercor noted that: *"Currently, there are risks from fully procuring (rather than owning or co-owning and having some control) DER such as the risk of service non-performance or other corporate stability issues. DNSPs bear the risk of unreliability through the [STPIS]. While contracts with DER providers could mitigate risks, not all providers may be willing or able to take on this risk. … Further, the transaction costs of design and monitoring detailed contracts with many small individual providers would be significant".*[110]

Other submissions to the contestability determination and the alternative to grid-supplied network services determination highlighted potential risks in relation to:

- transactions costs of establishing a contractual arrangement;[111]
- the necessity for contractual arrangements to compensate the NSP for penalties incurred in the event of failure to achieve reliability targets;[112, 113]
- third-party contractor insolvency;[114] and
- increased risk and complexity.[115]

While it is not implausible that such considerations are relevant factors, it is difficult to establish the extent to which they influence NSP decision making. Further, we note that many of the comments summarised above are objecting to proposed *requirements* for NSPs to contract with third-parties to access services, rather than expressing a general view on the disadvantages of opex/third-party solutions compared to capex/in-house options.

5.3. Summary

As with any qualitative assessment, we cannot say categorically that cultural or behavioural factors would result in a capex bias. However, at least for privately owned businesses, there

---

108 As we have discussed in the preceding sections the WACC is adjusted for systematic risk.
109 Endeavour Energy (2017), page 2.
110 SAPN / CitiPower / Powercor (2016), page 5.
111 AusNet Services (2017), page 5.
112 Ibid.
113 ENA (2017).
114 Essential Energy (2017).
115 Ausgrid (2017).

appears to be a strong perception that growing the RAB is good for investors, which is not always accompanied by an explicit reference to whether the actual WACC is higher than the allowed rate of return based on the BEE.

We also find it highly plausible that alternative (potentially innovative) solutions to undertaking traditional capex approaches may have higher risk associated with them, even if the expected cost is lower than the capex approaches. If investors and/or management are risk averse, then they may prefer the higher-cost option if the uncertainty around the expected cost is lower.

6. CONCLUSIONS

A key objective of the NEM regulatory framework, and recent rule changes, is to incentivise genuine outperformance and innovation to mimic the operation of a competitive market. At the time of the framework's development, the efficient, safe, and reliable conveyance of electricity primarily required capital investment in long-lived assets (wires, poles, etc.), and the design of the framework reflected this. The original design of the NEM regulatory framework is therefore unlikely to have anticipated the increasing availability of alternatives to 'traditional' (NSP-initiated, capex-based) approaches to delivering regulated network services, provided in-house by the NSP or out-sourced from third parties.

The framework is continually evolving, and a suite of incentive mechanisms is now in place to meet the requirements of various rule changes. However, the combination of these mechanisms, developed at different times over the last 10 to 15 years, may have resulted in unintended incentives on NSPs, or the NSPs misinterpreting and responding to the incentives incorrectly.

We have analysed the explicit financial incentives built into the regulatory framework and other factors that may influence NSP behaviour. It is important to bear in mind that the NSPs are still learning how the incentive mechanisms will work – the CESS has only been in place for one (and in most cases ongoing) regulatory control period and the DMIS is yet to be used. Nonetheless, our analysis indicates that:

- **The financial incentives for NSPs vary depending on individual circumstances, but they are not equal between opex and capex.** If we assume that an NSP is considering whether to undertake equally efficient opex or capex solutions, which deliver the same outcomes, our modelling indicates that the NSP will have a financial incentive to prefer capex over opex. In contrast, if we assume the opex solution lasts into perpetuity (rather than for the same length of time as the CESS) then there is a slight financial incentive for the NSPs to underspend on capex rather than opex.

- **The financial incentives are asymmetric if the NSPs' WACC is different from the allowed rate of return.** An NSP's financial incentive to undertake capex rather than opex is stronger when it can outperform the allowed rate of return. In addition, our analysis indicates that when an NSP's actual WACC is lower than the allowed rate of return, its financial incentive to undertake capex is stronger than its financial incentive to undertake opex if the situation was reversed.[116] In other words, the financial incentives when out-/ under-performing the allowed rate of return are asymmetric, and the asymmetry favours capex.

- **There is no simple fix to the EBSS and CESS to equalise the incentives on opex and capex.** The basis of the CESS *ex ante* sharing factor depends on an assumed in perpetuity opex saving and a fixed (pre-tax) discount rate of 6%. Neither of these

[116] Assuming that the NSP out-/under-performs the allowed rate of return by the same number of basis points.

assumptions are likely to hold in practice, particularly if the actual cost of capital is different from the allowed cost of capital.[117]

- **The DMIS provides an incentive, for specific projects, to favour demand management over 'network solutions'.** The DMIS can, depending on the specific requirements of the project, more than fully offset the financial bias in the underlying framework of the EBSS and CESS.
- **The AER assess capex differently from opex.** The AER typically uses revealed costs to set a base opex level, with benchmarking used to assess the efficiency of the base expenditure level. The base opex is then trended forward using estimates of outputs, productivity, and input prices. In contrast, a more bespoke assessment is used for capex as investment needs vary over time. NSPs may seek to avoid opex solutions to avoid appearing inefficient in the benchmarking. This creates both a financial incentive, as opex is more likely to be reduced than capex, and a reputational incentive.
- **The combined effects of the incentive mechanisms are complex.** We have found it difficult to model the interaction between all the financial incentives. We have predominately focused on modelling the CESS and EBSS, as it is not clear yet how the DMIS will work in practice with these other incentive mechanisms. The outcomes from the modelling depended on the assumptions we made. Each NSP will need to assess how the mechanisms apply to them and therefore how they should respond. Greater complexity increases the likelihood that NSPs will respond in unintended ways. We note that the AER has previously observed that incentives under the EBSS change if allowances are set exogenously (i.e., when a revealed cost approach in perpetuity is not used).[118] The AER did not apply an EBSS in the 2015 decisions for ACT and NSW, after benchmarking analysis was used to determine their allowed revenue; this suggests a level of uncertainty around how the incentive mechanisms will interact with the cost assessment framework in future.
- **'Network' capex is more likely to provide the NSPs with stable cash flows compared to more innovative opex solutions.** Aside from the DMIS, there is no explicit working capital allowance (margin on opex) for changes in the operational leverage of individual NSPs and any associated changes in their risk profile from adopting opex solutions with greater levels of uncertainty around future costs. Therefore, risk averse investors/ management may seek to avoid opex projects with greater uncertainty around future costs and outputs.

[117] Ofgem's and Ofwat's solution to this issue was to simplify the incentive mechanism by treating opex and capex together and capitalising a proportion of the total. This approach does lead to changes in other part of the regulatory framework (such as the treatment of depreciation and the need for financeability assessments).
[118] AER (2013a).

- **Anecdotal evidence indicates that investors are interested in stable long-term cash flows.** Therefore, any shift away from maintaining or growing the regulatory asset base (RAB) will reduce the magnitude of future profits, and therefore future dividend growth. This preference appears to disregard the theory that investors should be indifferent to an opex or capex solution if the allowed rate of return is set equal to their actual cost of capital, and that the size of equity and debt will reduce alongside the RAB.

More generally, we note that the current regulatory framework was developed with a RAB based approach at its heart. This incentivised capex, as no return (a margin) was provided on opex to cover working capital. The provisions of the current regulatory framework have in turn attracted a certain type of investor. This may create a self-reinforcing capex bias.

Overall, the analysis we have undertaken highlights the complexity of the interaction between the incentive mechanisms and how the perception of the incentives can change depending on the assumptions made. While we are unable to prove the presence of a systematic capex bias, we can conclude that the incentives provided by the current regulatory framework are not balanced across capex and opex. NSPs need to consider carefully the interaction between the incentive mechanisms, and this may affect the accurate identification of the option that will deliver the most efficient, reliable, and safe solution for consumers. This may be appropriate in the short term. For example, we note that the DMIS is intended to encourage a broader uptake of demand management solutions.[119] However, in the longer term, we consider that options to simplify and streamline the incentive framework should be investigated, particularly as the availability and feasibility of alternative options to traditional network solutions is anticipated to increase.

[119] AER (2017c).

ANNEX A REFERENCES

AEC (2017), *Contestability of Energy Services Rule Change – Submission to Consultation Paper*, February 2017.

AEMC (2012a), *Power of Choice – giving consumers options in the way they use electricity, Supplementary Paper - demand side participation and profit incentives for distribution network businesses*, 23 March 2012.

AEMC (2012b), *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, November 2012.

AEMC (2017), *Rule Determination, National Electricity Amendment (Contestability of energy services) Rule 2017,* December 2017.

AER (2013a), *Better Regulation: Explanatory Statement – Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013.

AER (2013b), *Better Regulation: Explanatory Statement – Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.

AER (2013c), *Better Regulation: Explanatory Statement – Rate of Return Guideline*¸ December 2013.

AER (2015a), *Final Decision Ausgrid distribution determination 2015-16 to 2018-19: Attachment 7 – Operating expenditure,* April 2015.

AER (2015b), *Electricity distributors 2011-13 performance report*, June 2015.

AER (2015c), *Demand Management Incentive Scheme – Rule Determination*, August 2015

AER (2017a), *Regulatory investment test for distribution application guidelines*, September 2017.

AER (2017b)*, Ring-fencing Guideline Version 2,* October 2017*.*

AER (2017c), *Demand management incentive scheme – explanatory statement,* December 2017.

AER (2018), *Review of the RIT application guidelines – Issues Paper*, February 2018.

Ausgrid (2017), *Contestability of Energy Services Rule Change – Submission on Draft Determination*, November 2017.

AusNet Services (2017), *Draft Rule Determination: National Electricity Amendment (Alternatives to grid-supplied network services) Rule 2017*, Submission to AEMC, 8 November 2017.

Averch et al (1962). Averch, Harvey & Johnson, Leland L., *Behavior of the firm under regulatory constraint.* The American Economic Review, 52 (5) (Dec 1962), 1052-1069.

Berenberg (2017), *National Grid plc*, January 2017.

Credit Suisse (2014), *Spark Infrastructure Group*, December 2014.

Credit Suisse (2016a), *National Grid – Equity Research*, June 2016.

Credit Suisse (2016b), *National Grid – Equity Research*, April 2016.

Dunstan et al (2017), Dunstan, C., Alexander, D., Morris, T., Langham, E., Jazbec, M., 2017, *Demand Management Incentives Review: Creating a level playing field for network DM in the National Electricity Market* (Prepared by the Institute for Sustainable Futures, University of Technology Sydney).

Economic Insights (2012), *The use of actual or forecast depreciation in energy network regulation*, May 2012.

ElectraNet (2018), *Electricity Network Economic Regulatory Framework Review 2018 (EPR0062), submission to the AEMC,* letter dated 2 May 2018.

ENA (2017), *Contestability of Energy Services Rule Change – Response to AEMC Consultation Paper*, February 2017.

Endeavour Energy (2017), *Contestability of Energy Services Rule Change – Submission to Consultation Paper*, February 2017.

Essential Energy (2017), *Alternative to Grid-Supplied Network Services – Response to Draft Rule Determination*, November 2017.

Essential Services Commission (ESC) (2006), *Electricity Distribution Price Review 2006-10 – October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006: Final Decision Volume 1 Statement of Purpose and Reasons,* October 2006.

Frontier Economics (2017), *Total expenditure frameworks – A report prepared for the Australian Energy Market Commission*, December 2017.

KPMG (2018), *Optimising network incentives – a report prepared for the Energy Market Transformation Project Team*, January 2018.

Macquarie (2015a), *DUET Group – DBP still some downside risk*, March 2015.

Macquarie (2015b), *European utilities – Back to the 19th Century*, September 2015.

Macquarie (2016), *European utilities – Fast forward to the 21st Century*, May 2016.

Morgans (2017), *Spark Infrastructure – Transgrid Draft Decision + CEO Presentation*, September 2017.

Ofwat (2011), *Capex bias in the water and sewerage sectors in England and Wales – substance, perception or myth? A discussion paper*, May 2011.

Ofwat (2014), *Setting price controls for 2015-20, Final price control determination notice: policy chapter A7 – risk and reward*, December 2014.

PSC (2015), Public Services Commission of New York, *Staff white paper on ratemaking and utility business models*, July 2015.

RBS Morgans (2013), *Poles, wires, and pipes*, August 2013.

SAPN / CitiPower / Powercor (2016), *Contestability of Energy Services Rule Change – Submission to Consultation Paper*, February 2016.

Wood, T., Blowers, D., and Griffiths, K. (2018). *Down to the wire: A sustainable electricity network for Australia*. Grattan Institute.

ANNEX B MODELLING ASSUMPTIONS

In Table B1 we set out the assumptions used in our modelling. These follow the assumptions that the AER typically use for the PTRM, RFM, CESS and EBSS.

Table B1: Model assumptions

Assumptions
We assume all expenditure is in real terms (i.e., zero inflation)
Starting rate of return of 6%
We assume that future opex allowances in perpetuity are set based on the fourth year of the first regulatory control period.
Capex occurs during the middle of the year, and a half year rate of return is applied.
Depreciation is straight-line.
The RAB is rolled forward using actual capex and forecast depreciation. Forecast depreciation in future periods is then adjusted for the remaining asset life and RAB.
Rate of return applies to RAB at the beginning of the year.
Tax is 30%. Depreciation used for tax purposes differs from depreciation if there is an over-/ under-spend.