Review of incentives schemes for networks

Draft Decision

December 2022

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Tel: 1300 585 165

Contents

Request for submissions

We, the Australian Energy Regulator (AER) invite interested parties to make written submissions on this draft decision for our review of expenditure incentive schemes for NSPs. Please provide submissions by 5pm AEST **3 March 2023**.

Submissions should be emailed to incentivereview@aer.gov.au. Alternatively, you may mail submissions to:

Sebastian Roberts
Network Expenditure
Australian Energy Regulator
GPO Box 3131
Canberra, ACT, 2601

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. We will treat submissions as public documents unless otherwise requested. All non-confidential submissions will be placed on the AER's website. For further information regarding the AER's use and disclosure of information provided to it, see the ACCC/AER Information Policy.

We request parties wishing to submit confidential information:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission in a form suitable for publication.

Summary

Most countries, including Australia, have adopted incentive regulation which rewards regulated businesses for improving consumer outcomes by reducing costs and improving service outcomes.

Price cap and revenue cap regulation as established in Australia, the UK and New Zealand encourage network service providers (NSPs) to find efficiency gains. If NSPs send less on operating and capital expenditure than forecast they retain the benefits for the rest of the regulatory period (which is typically five years). In the absence of incentive schemes though, incentives weaken over the regulatory period.

Our incentive guidelines supplement the price and revenue cap framework to provide even incentives for efficiency through the regulatory period. The approach is set out in our 2013 Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) guidelines. Incentives for efficiency are supplemented by our Service Standard Performance Incentives Scheme (STPIS) which provides incentives for improved service standards.

The information revealed by our incentive schemes is used to set future revenue forecasts. The efficiency gains are shared between consumers and NSPs:

- NSPs retain 30 per cent of all capital expenditure savings
- NSPs retain all operating expenditure savings for 6 years
- NSPs retain benefits of reliability improvements for 5 years (quantified using the value of customer reliability).

Consumers have reservations about incentive schemes

One reason for this review is that while incentive schemes are intended to reward businesses for promoting improved consumer outcomes, consumers have expressed concerns about the amount they pay for incentive schemes. In aggregate, the EBSS, the CESS and the STPIS payments have added up to 2 per cent to revenues over the past five years, which is equivalent to $1.2 billion.

The question for consumers is whether these incentive payments are worth it. In recent electricity distribution determination processes, consumers expressed concerns about a lack of transparency about consumer benefits from the incentive schemes compared to the observed costs. Consumers have also questioned the extent to which NSPs are being rewarded for expenditure over-forecasting rather than efficient spending, particularly in the context of capital expenditure.

The schemes have improved efficiency with benefits for consumers

Our assessment of the available data shows that the incentive schemes have driven significant efficiency gains, which provides benefits to consumers in terms of lower prices. For electricity distribution:

- operating expenditure is down 30 per cent per customer since 2011/12
- capital expenditure is down around 50 per cent per customer since 2011/12
- these efficiency gains contributed to the 35 per cent reduction in networks revenues per customer since 2014/15
- in 2021 we also had a record low frequency and duration of outages with improvements of 20 to 30 per cent in those measures over the past 10 years.

While NSPs have been rewarded for the efficiency gains, most of the benefits have gone to consumers. We therefore propose to retain the schemes with modifications.

Operating expenditure incentives are fit for purpose

Regulators and consumers have incomplete information about future operating costs. Our primary tool for addressing this is to use past expenditure outcomes as a starting point with incentives for

NSPs to improve efficiency over time. The incentives reveal what can be achieved and are then used as the basis for future forecasts.

The EBSS is the mechanism which shares the benefits of operating cost reductions between consumers and NSPs. Our analysis shows that the scheme has contributed to improved efficiency and lower prices and is working as intended. The benefits to consumers are up to four times the benefits to NSPs.

Our revealed cost approach is supplemented by our use of a productivity factor in forecasts. The productivity factor means NSPs must beat their historic performance by more than 0.5 per cent per annum before they are rewarded with EBSS payments.

One of the issues raised by consumers is whether we should use benchmarking more aggressively in setting our expenditure forecasts. We use benchmarking to set operating expenditure forecasts when an NSP's performance is less than 75 per cent of the most efficient NSP. As we refine our benchmarking techniques there may be a case to revise the 75 per cent target so that benchmarking is applied at a point closer to the efficiency frontier. We will consider this further and report on it in future benchmarking reports.

We consider that the EBSS remains fit for purpose. We propose to retain the EBSS along with implementing enhanced transparency and consideration of further refinements to our benchmarking approach.

There is scope to improve the Capital Expenditure Sharing Scheme

For capital expenditure we also use a revealed cost approach. We have improved the way we use revealed costs in our forecasts by developing a replacement capital expenditure (repex) model and by refining other elements of our approach. As a result, the gap between our forecasts and actual expenditures has narrowed over time, from around 18 per cent for the first round of resets made after we introduced the CESS to 7 per cent for current resets.

Nevertheless, applying a revealed cost approach to capital expenditure is more difficult than operating expenditure because of the often lumpy and sometimes non-recurrent nature of capital expenditure. While replacement capital and elements of IT expenditure are largely recurrent, augmentations are not, especially for large new transmission projects. This means the CESS does not have the same information revelation properties as the EBSS and some forecasting error is inevitable.

The current CESS applies a 30 per cent sharing ratio. NSPs retain 30 percent of any underspending against our forecast, and the balance goes to consumers. In this draft decision, we propose to improve outcomes for consumers by limiting CESS rewards for NSPs when outperformance is high, by improving transparency and potentially by limiting application of the CESS in the case of large transmission investments. Our proposal is to vary the CESS to apply a tiered arrangement:

- a 30 per cent sharing ratio for any underspend up to 10 per cent of the forecast capital expenditure allowance in the previous regulatory control period
- a 20 per cent sharing ratio for any underspend that exceeds 10 per cent of the forecast capital expenditure allowance in the previous regulatory control period
- a 30 per cent sharing ratio for any overspend of the forecast capital expenditure allowance in the previous regulatory control period.

The proposal has been designed to be asymmetric. Despite improvements in our assessment toolkit and stakeholder engagement, a level of information asymmetry between the AER, consumers and the NSPs remains. The risk of over forecasting capex requirements remains higher than under forecasting. Given this, applying the Bright-Line Tiered Test asymmetrically has the effect of providing an offset to potential asymmetry in forecast error.

Our proposed transparency measures will enhance our Regulatory Information Notices (RINs) by requiring NSPs to explain the reasons for variations between operating and capital expenditure outcomes and forecasts. We will implement this as part of the Networks Information Requirements Review that we are currently undertaking. This will help stakeholders better understand the extent to which genuine efficiency gains have driven outcomes.

For large transmission investments our proposed approach is to consider whether the CESS is fit for purpose on a case-by-case basis in the context of our consideration of such investments in regulatory reset proposals and contingent project proposals.

Elements of the STIPS need reviewing

Our discussion paper focused on the EBSS and the CESS, arguing that the STPIS remains fit for purpose and does not need significant changes. The majority of submissions supported this view.

However, transmission networks are concerned about the Market Impact Component (MIC) of the transmission STPIS. Transmission outages can affect market outcomes, with the possibility of high spot market prices when there are significant transmission constraints. The MIC provides networks with incentives to manage outages in a way that limits market impacts.

The MIC sets performance targets based on historic data. However, high investment in variable renewable energy generation is creating greater and more widespread congestion, significantly increasing network constraints above historical averages. Transmission networks consider that they are being penalised for changes in the generation mix rather than their performance.

We consider it prudent to review the MIC in light of increasing transmission congestion. Our draft decision is to conduct a review of the MIC starting in the second half of 2023, which would allow any revisions to be picked up in time for the next Queensland and South Australian transmission reset processes. As the Network Capability Incentive Parameter Action Plan (NCIPAP) is closely linked to the MIC, our position is to review the NCIPAP scheme alongside the MIC review.

Two other elements of our service standards incentives are the DMIS and DMIA. These are relatively recent initiatives (introduced in 2017) and were considered as part of a STPIS review in 2018. To date the schemes have incentivised several projects and we are proposing to extend application of the schemes to export services.[1] We are not proposing further review the schemes at this point.

Draft decision

In summary, our position in this draft decision is to:

- retain the EBSS
- vary the CESS by implementing a tiered arrangement, with a 30 per cent sharing ratio for any underspend up to 10 per cent of the forecast capital expenditure allowance, a 20 per cent for any underspend over 10 per cent and a 30 per cent sharing ratio for any overspend
- improve the transparency of, and the reasons for, differences between our expenditure forecasts and the actual expenditures as part of the Networks Information Requirements Review and the forthcoming RINs we will serve on SAPN, Ergon Energy and Energex
- undertake a review of the MIC component of the transmission STIPS.

In terms of timing, we seek views on whether the changes should apply to the upcoming NSW, ACT and Tasmanian resets which commence early in 2023. We propose to apply any future changes to the STPIS and related schemes in 2024 and apply them to the next transmission resets in SA and Queensland.

Varying the CESS will require amending our Capital Expenditure Incentive Guideline for Electricity Network Service Providers (Capex Incentive Guideline), which we first published in 2013. We have included a copy of the amendments on our website.

[1] AER consultation paper: Incentivising and Measuring Export Service Performance, August 2022

1. Background

In December 2021, we commenced a review of incentive schemes focusing on the Efficiency Benefit Sharing Scheme (EBSS), the Capital Expenditure Sharing Scheme (CESS) and the Service Standards Performance Incentives Scheme (STPIS). This review is part of a broader program to incrementally improve our approach to regulation as reflected in the 'tilt' priorities outline in our Strategic Plan for 2020-25.

The EBSS and the CESS have been in place since 2013. The STPIS has been in place since 2008. We now have data to assess the effectiveness of the schemes and whether there is scope for improvement. We have also received consumer feedback on the EBSS and the CESS. In recent regulatory determinations for the Victorian and South Australian electricity distributors, consumers observed significant differences in expenditure forecasts and actual expenditure outcomes along with significant incentive rewards. Consumers are asking whether the incentive schemes are working as intended and providing value for money.

Other elements of our program to improve network regulation include:

- our *Better Resets Handbook Toward Consumer Centric Network Proposals* (the Better Resets Handbook). This is designed to strengthen the reputational and procedural incentives on electricity networks in preparing their regulatory proposals and engaging with customers
- our review of incentive arrangements for export services
- refining our approach to benchmarking including the operating environment factors review we carried out in 2018 and the capitalisation review we are undertaking at the moment
- our 2022 review of rate of return parameters.

In addition, we continue to report annually on electricity network performance and benchmarking outcomes. The information in these reports provides transparency about network performance and helps inform our assessment of the performance of incentive schemes.

In response to our discussion paper released in December 2021, we received 16 submissions in response from networks and consumer representatives.

Much of the focus of submissions was on the CESS. To further develop our approach to the CESS we released a position paper in August and held a stakeholder forum. We received a further nine submissions following the stakeholder forum.

This draft decision sets out our views on, and proposed approach to, the EBSS, the CESS and the STPIS. We will draw on submissions in response to the draft decision in finalising this review. We plan to release our final decision in April 2023.

Changes to our 2013 Capex Incentive Guideline will be required if our draft decision is to be implemented. We have included a copy of the amendments we propose to make on our website.

2. Efficiency Benefit Sharing Scheme

2.1 About the EBSS

How the EBSS works

The objective of the EBSS is to provide electricity and gas network service providers (NSPs) with an even incentive to undertake efficient opex in any given year during a regulatory control period. The scheme removes the declining incentive for cost reductions and efficiencies over the regulatory period, encourages greater efficiency, and provides better information revelation from the business that exists in its absence. The EBSS does this by allowing networks to retain efficiency gains, and efficiency losses, for a total of six years. This results in the EBSS sharing efficiency gains and losses between NSPs and consumers in a ratio of approximately 20:80 now and 30:70 at the time we released our guideline. A variant on the EBSS is included in gas access arrangements.

The EBSS provides NSPs with incentives to undertake efficient operating expenditure during a regulatory control period. Where the NSPs undertake efficient expenditure, we can use this to forecast efficient operating expenditure in subsequent periods. These are reflected in the charges that customers pay in electricity bills.

When forecasting operating expenditure, we typically start with a single year of actual operating expenditure (the base year) to forecast future requirements. We test the efficiency of operating expenditure in the base year using our benchmarking analysis. We use actual operating expenditure in the base year if we find it to be efficient, or we make an efficiency adjustment if we determine it to be inefficient.

Once base year expenditure is set, we forecast opex by adjusting for factors such as forecast regulatory changes, input price changes, output growth. We also forecast productivity improvements of 0.5 per cent each year. This is the revealed cost base-step-trend forecasting approach, which we describe in our *Expenditure forecast assessment guideline*.

The EBSS allows NSPs to retain the benefit (or incurs the cost) of outperforming (underperforming) against the forecast for 6 years. There are two reasons for applying the EBSS:

- It removes incentives for NSPs to increase opex in the expected 'base year' to increase its forecast opex allowance for the following regulatory control period.
- It maintains incentive levels through the regulatory period. Without the EBSS the NSP only retains the efficiency gains for the balance of the regulatory period, resulting in declining rewards for cost reductions as the regulatory period progresses and low incentives in the final years. This can encourage the NSPs to defer ongoing efficiency gains until early in the next regulatory period.

Rule requirements

How the EBSS is currently applied is set out in the Efficiency Benefit Sharing Scheme Guideline.[2] Any changes we may make to the EBSS must be done so in a manner that will or is likely to contribute to the achievement of the National Electricity Objective (NEO).

In developing and implementing the EBSS, the NER require us to have regard to:[3]

- the need to provide NSPs with a continuous incentive to reduce opex

[2] AER, *Better Regulation, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.

[3] NER, cll 6.5.8(c) and 6A.6.5(b).

- the desirability of both rewarding NSPs for efficiency gains and penalising them for efficiency losses
- any incentives that NSPs may have to capitalise expenditure
- the possible effects of the scheme on incentives for the implementation of non-network alternatives
- the benefits to electricity consumers likely to result from the scheme.

2.2 Stakeholder views

In response to the discussion paper, we received 16 submissions from network, consumer group and retail stakeholders.

Generally, consumer groups see scope to improve the EBSS scheme. They are concerned about the time lag before consumers see the benefits of efficiency improvements, and question whether some NSPs are being over-rewarded for cost improvements. The consumer groups suggest:

- improving forecasts by better anticipating future productivity gains
- potentially linking the EBSS sharing ratio to productivity forecasts
- improving transparency about the reasons for differences in opex forecasts and outcomes.

The Consumer Consultative Panel (CCP) suggests we forecast higher productivity growth than our current 0.5 per cent per annum forecast or that we link the EBSS sharing ratio to productivity forecasts. In the second scenario, NSPs proposing higher productivity factors would be rewarded with a higher EBSS sharing ratio.

The Network of Illawarra Consumers of Energy (NICE) proposes varying forecast productivity growth across NSPs with a ‘zero adjustment’ for the most efficient firms and progressively higher forecast productivity growth the further a NSP is from the efficiency frontier.

The consumer groups’ proposals are driven by concerns that less efficient NSPs are being over-rewarded for catching up to their more efficient counterparts.

NICE has broader concerns with the revealed cost model and would prefer rule changes to allow performance-based regulation based on benchmarking.

Retail stakeholders have reservations about the extent to which opex underspends represent genuine efficiency gains. They are encouraging us to continue to improve opex forecasts.[4]

Submissions from the ENA and NSPs support retaining the EBSS and for the most part support retaining it in its current form. More specifically, the NSPs submit:

- the EBSS is operating as intended and is fit for purpose
- consumers have benefited consumers from lower network prices and improved service quality. The ENA engaged Houston Kemp to assess the costs and benefits of the CESS, EBSS and STPIS. It compared actual opex outcomes to forecasts from 2006 to 2020 to estimate EBSS[5] gains to consumers of approximately $7 billion compared to EBSS costs of approximately $3 billion.
- There are strong safeguards on opex forecasts including the Better Resets Handbook and enhanced AER expenditure forecasting techniques.

4 Origin Energy, 11 March 2022; Red Energy, 17 March 2022.

5 Or the equivalent operating expenditure incentives scheme in place before 2013

- Recent inclusion of a productivity factor means forecasts factor in expected productivity improvements.

One of the questions the AER posed in its Discussion Paper was the balance of incentives between the CESS and EBSS. When the AER released its Incentives Guidelines in 2013 the EBSS delivered a 30:70 sharing ratio between NSPs and consumers. The CESS was set on this basis. Since then, the relevant rate of return parameters have changed, resulting in a decrease in the rate of return up until 2021, and leading to a subsequent decrease in the EBSS sharing ratio. Houston Kemp estimates that the sharing ratio was 18:82 in 2020. The sharing ratio remains at around that level now.

Views on how to address the imbalance between the CESS and the EBSS sharing ratios differ:

- Most NSPs submit that there is no evidence that the gap between the EBSS and CESS is distorting behaviour and there is no case to change either the EBSS or the CESS sharing ratio. Their point is that there is limited discretion in allocating costs between opex and capex as most expenses fall clearly into one category or another. They also point out that any material shifts will become evident in regulatory reporting.
- Some of the NSPs see a case for aligning the CESS and EBSS sharing ratios by fixing the opex sharing ratio at 30:70. Essential Energy and Transgrid suggest mechanisms for achieving a revised 30:70 split.
- On the consumer side NICE submits that it is appropriate for the EBSS to vary with the time value of money. Their suggestion is to reduce the CESS sharing ratio to achieve alignment.

Use of benchmarking to set base opex was also addressed in some submissions. NICE favours greater use of benchmarking in setting forecasts and incentive ratios. By contrast NSPs are more cautious. Energy Queensland sees merit in reviewing the AER's approach to making efficiency adjustments to base opex (using benchmarking) as moving away from revealed costs distorts the operation of the EBSS. AusNet is concerned about the robustness of benchmarking given differences in capitalisation practices across networks.

A summary of submissions is set out in Appendix A.

2.3 Discussion

Opex is largely recurrent and is for the most part well suited to a revealed cost incentive model. The data suggests the EBSS has contributed to significant efficiency gains and that consumers have benefited with lower prices.

However, consumer groups consider there is scope to improve opex forecasts and question the scale of EBSS payments to NSPs catching up to their more efficient counterparts. They also seek increased transparency about expenditure outcomes.

Some of the NSPs want changes to the EBSS to align incentive rates with the CESS.

In considering the questions raised by stakeholders we consider:

- The EBSS's contribution to NSP efficiency
- The scope for improving forecasting accuracy
- Whether there is a case to change the EBSS sharing rates
- Linkages between benchmarking, the revealed cost model and the EBSS.

Efficiency gains

Since 2012 total opex costs have trended down, opex per customer has fallen and measures of opex productivity have improved.

Figure 1 shows the total actual and forecast operating expenditure across electricity distribution networks in the NEM. This shows that total operating expenditure peaked in 2012 and has since been declining, with a consistent downwards trend observed since 2014 and 2015.

We significantly reduced our opex forecasts in 2015 following implementation of our Better Regulation reform program in which we started measuring and applying economic benchmarking of electricity networks. Since then, our forecasts have trended slightly upwards because of increasing labour costs and significant new regulatory obligations such as new bushfire and cyber-security requirements.

The electricity distribution networks struggled to meet our forecasts after 2015, spending more in aggregate than our forecast in 2015, 2016 and 2017. However, steady reductions in opex saw the distributors out-perform our forecasts in 2018, 2019 and 2020.

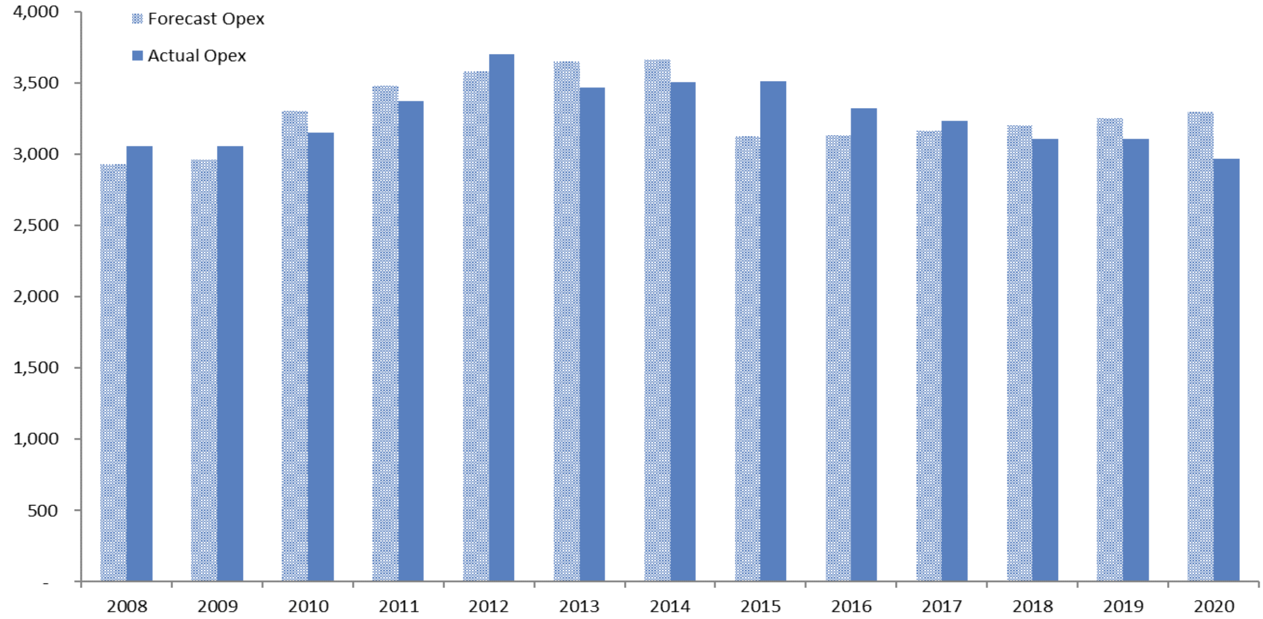
The opex reductions translated into lower electricity distribution costs per customer as shown in Figure 2. Opex per customer fell from $412 in 2011/12 to $287 in 2020/21, a reduction of 30 per cent. Similarly, opex costs fell for electricity transmission customers, from $68 per customer in 2015/16 to $57 in 2020/21, a 16 per cent reduction.

As shown in Figure 3, operating expenditure declines have contributed to significant growth in the measured productivity of electricity distribution businesses across the NEM since 2015 (as demonstrated by the increase in operating expenditure partial factor productivity, or 'opex PFP').

The benefits of these cost reductions have been shared between consumers and the networks. While the EBSS has always allowed networks to retain the benefits of cost reductions for six years, the net present value of those benefits to the distributors has varied as rate of return parameters changed over the years. At the time we released our Incentive Guidelines in 2013 our estimate of the share of benefits going to consumers was around 70 per cent. By 2020 the share going to consumers increased to around 82 per cent.

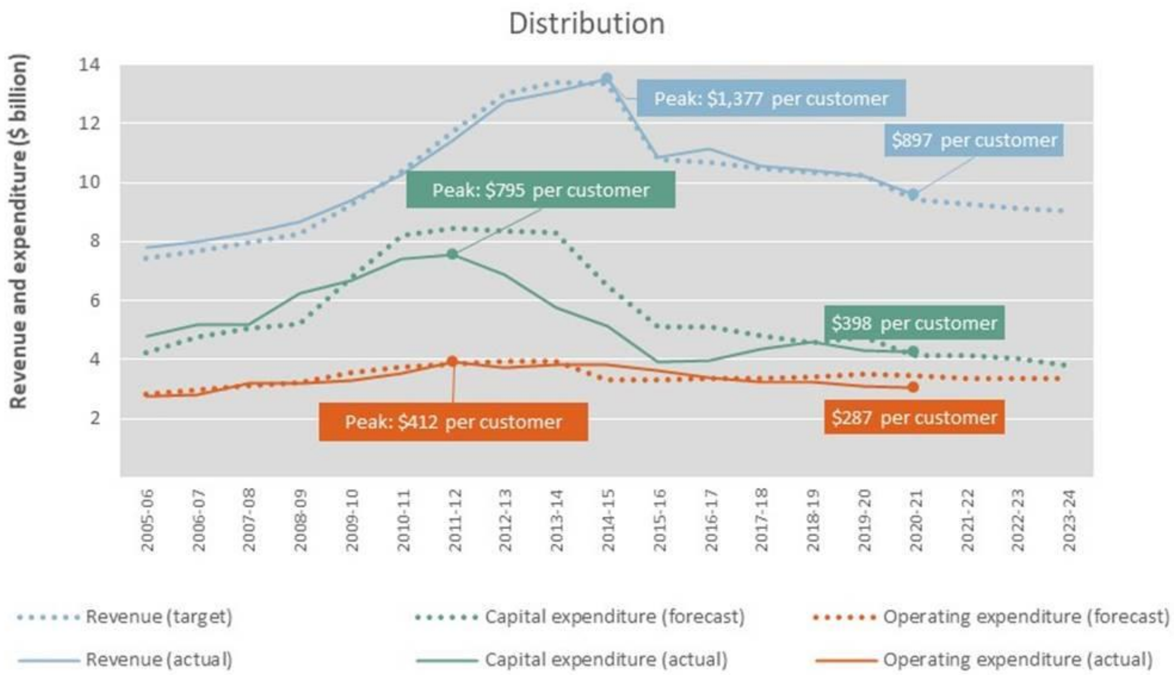
The AER considers that the EBSS has successfully driven opex efficiency gains in conjunction with our revealed cost opex forecasting approach and our approach to benchmarking. Our draft decision is to retain the EBSS.

Figure 1: Actual and forecast operating expenditure, electricity distributors, $m 2020



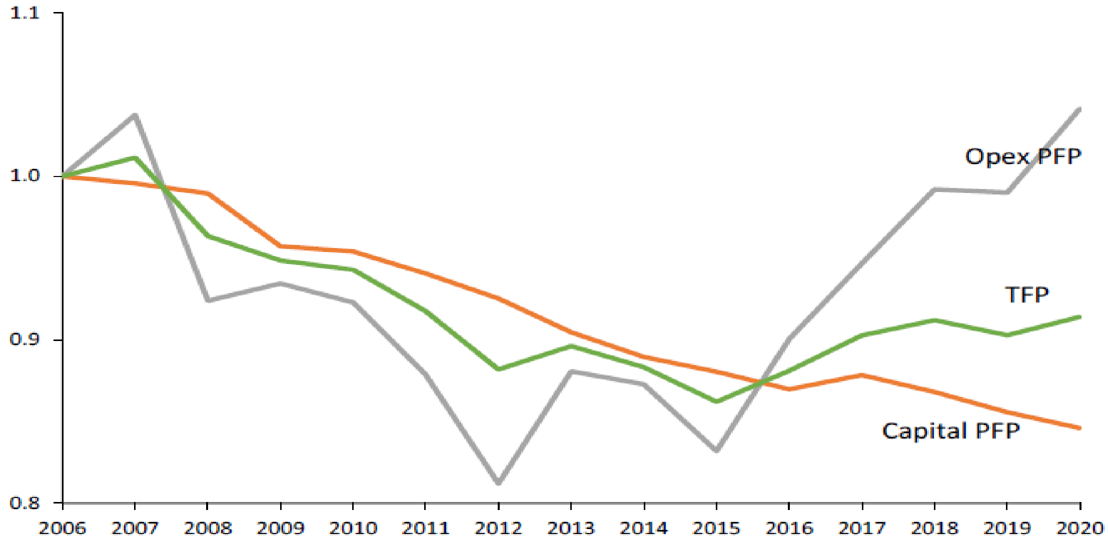
Source: AER network performance report

Figure 2: Revenue and expenditure, electricity distributors, $m 2020



Source: AER analysis

Figure 3: Operating expenditure and capital multi-lateral partial factor productivity, and total factor productivity, electricity distribution, 2006 to 2020



Source: AER 2020 electricity distribution benchmarking report

Forecasting accuracy

Figure 4 shows total approved forecast opex for electricity distributors per customer from 2011 to 2021. Since we applied benchmarking to base opex forecasts in 2015, our forecasts have been steady in real terms. This outcome is favourable for consumers to the extent that forecasts have absorbed cost pressures:

- over the period governments introduced new obligations on distributors including for bushfires and cyber-security
- some costs were re-allocated from capex to opex
- wage input costs grew more quickly than inflation.

Since 2018 electricity distributors have outperformed our targets with lower actual expenditure than forecast. These outcomes will be captured in future opex forecasts.

As noted in our discussion paper, we consider that electricity distribution networks can be split into 3 different groups based on their EBSS outcomes and benchmarking performance in recent years:

1. Networks that perform well in operating expenditure benchmarking and which have accrued only modest EBSS carryover amounts.
2. Networks that perform less well in the operating expenditure benchmarking but which we have not found to be materially inefficient, and to which we have applied the EBSS. These tend to be the networks that accrue the largest EBSS carryover amounts.
3. Networks that perform worst in our operating expenditure benchmarking and which we have found to be materially inefficient. In these cases, we have previously chosen not to apply the EBSS because we were not confident that we would use the networks' revealed expenditure to forecast operating expenditure in subsequent periods. Consequently, these networks have not accrued any carryovers.

Table 1 shows the NSPs with the highest EBSS carry-overs. They all fall into the second of the groups, namely networks that have performed less well in the operating expenditure benchmarking, but which we have not found to be materially inefficient.

In each case the NSPs listed in Table 1 undertook significant cost reduction programs. Endeavour steadily reduced employment levels since privatisation, while Energex, Ergon and United Energy cut costs as part of merger programs. Similarly, AusNet undertook a major efficiency program, in part because of slippage in its benchmarking performance. Consumers have and will continue to benefit from these improvements.

Consumer groups remain concerned about high EBSS payments to less efficient NSPs who are catching up to NSPs on the efficiency frontier. The CCP's submission argues for higher productivity growth forecasts, while NICE makes a case for higher productivity growth forecasts for firms away from the efficiency frontier.

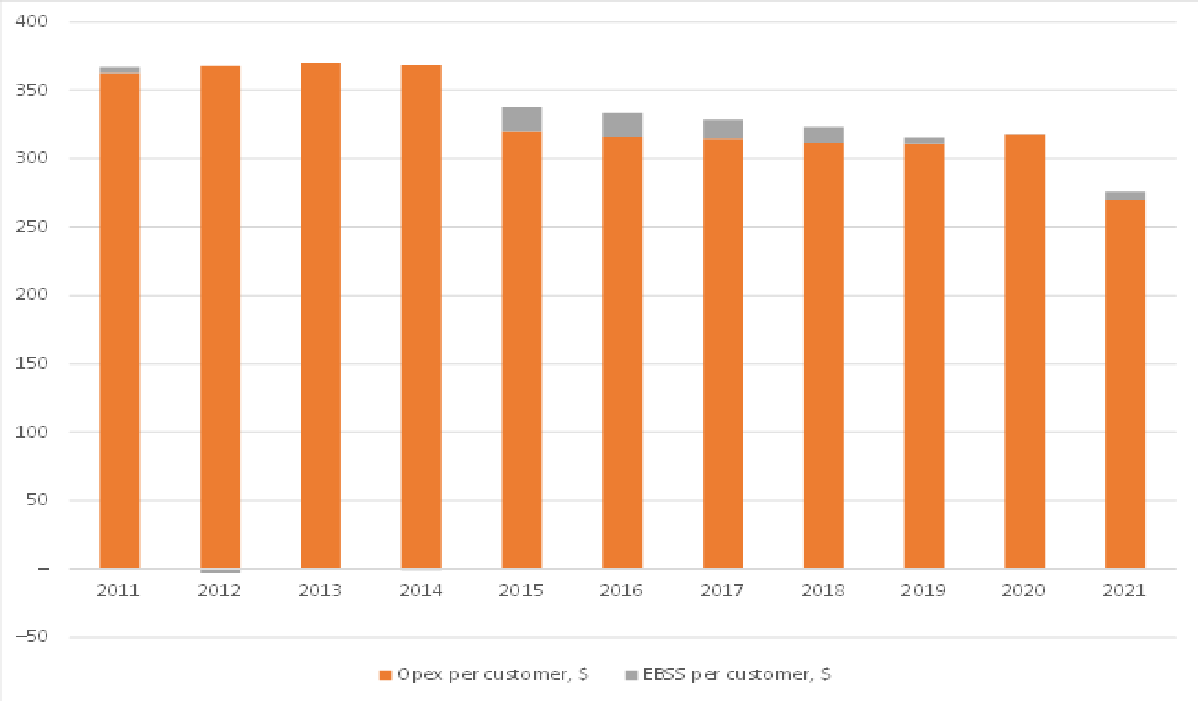
Our draft decision is to retain our current approach to forecasting:

- The recent introduction of productivity forecasts goes some way to addressing consumer group concerns. We now forecast productivity growth of 0.5 per cent per annum for electricity distributors, or 2.5 per cent over a five-year period. This anticipates future productivity gains and is based on an assessment of utility wide performance over an extended period.
- There are practical limitations to using benchmarking to set differential productivity forecasts. Benchmarking is a very powerful tool for identifying material inefficiency but is less well suited to identifying smaller differences in efficiency between NSPs given factors such as network density, vegetation and topography and jurisdictional regulation vary across NSPs.
- Over time the performance gap between NSPs has narrowed as less efficient NSPs have undertaken efficiency programs[6]. As noted by Endeavour Energy further opex improvements are likely to be harder in future as opportunities to address organisational and structural inefficiencies are exhausted.

There may be a case to improve our approach to identifying material inefficiency and setting the opex base. This is explored in the benchmarking discussion below.

[6] 2021 Annual Benchmarking Report – Distribution Network Services

Figure 4: DNSP operating expenditure and EBSS forecasts per customer, $m 2020



Source: AER analysis

Table 1: Largest total EBSS carryovers over the period 2020 to 2025, $million

Network	EBSS rewards, 2020 to 2025
Endeavour Energy	$240.2
AusNet Services	$115.9
Ergon Energy	$102.2
United Energy	$70.8
Energex	$70.7

Source: AER analysis

EBSS sharing rate

The EBSS allows networks to retain the benefits of any opex reductions, relative to forecast opex, for six years. Consumers receive their share of opex reductions through lower allowed revenues thereafter as the revealed lower opex is reflected in subsequent opex forecasts. The share of opex reductions retained by the network, in percentage terms, can be calculated by comparing the present value of six years of an opex reduction compared to the values of the opex reduction in perpetuity. At the time we released our Capital Expenditure Incentive Guideline and the current version of the EBSS in 2013 we estimated the share of benefits going to consumers was around 70 per cent. By 2020 the share going to consumers increased to around 82 per cent and remains around that level now. The sharing ratio has fallen for network businesses because of changes in rate of return parameters, in particular a decrease in the estimated rate of return up until the past year. We can expect further changes in the sharing ratio as those rate of return parameters evolve in future.

The change in the EBSS sharing ratio raises two potential issues. One is that incentives for networks to make opex efficiency gains are diluted. The second is that there is an imbalance of incentives between the CESS and EBSS. The change in rate of return parameters creates a gap between the EBSS sharing ratio and the 70:30 ratio which is locked into the CESS. The imbalance may distort incentives by encouraging cost shifting from opex to capex or increasing management effort to cut capex compared to opex.

Overall, though, we do not consider there is a case to change the EBSS sharing ratio as NSPs continue to reduce opex. The available data does not show a material difference in cost cutting efforts by the NSPs in response to fluctuations in the EBSS sharing ratio over time. As noted by several NSPs in their submissions, there is limited discretion in allocating costs between opex and capex as most expenses fall clearly into one category or another. Because of this there is little scope for the imbalance in sharing ratios to distort NSP behaviour.

In response to consumer group suggestions the AER will improve transparency about opex outcomes and the balance between capex and opex spending. Along with the AER's annual network performance reports the information should assist stakeholders assess these issues further in future.

EBSS and benchmarking

As discussed above, consumer groups remain concerned that our forecasts are not ambitious enough for less efficient NSPs, and that they are being over-rewarded for 'catch up' efficiency.

One way of improving forecasts is to use benchmarking. We use benchmarking to:

- compare opex performance across electricity distribution NSPs
- make an efficiency adjustment to base opex where we consider a NSP's revealed opex is materially inefficient
- determine output growth weights which we use to forecast output growth when we forecast opex
- inform our forecast of productivity growth.

While revealed cost is our primary forecasting tool, we recognise that not all NSPs respond to the EBSS in the way intended. We have used benchmarking to make efficiency adjustments to revealed costs for Ausgrid, Evoenergy and Power and Water. Benchmarking has also influenced opex proposals submitted by networks such as Jemena and AusNet. When we use benchmarking to set opex forecasts, we typically suspend the EBSS until opex outcomes improve to the point where they are no longer materially inefficient.

We use an efficiency benchmarking comparison point of 0.75 to determine material inefficiency. This means that an electricity distributor can have a benchmarking score that is 25 per cent less than the most efficient NSP before we use benchmarking to make an efficiency adjustment to revealed opex.[7] In applying a comparison point we err on the side of caution before departing from our revealed cost approach given the different circumstances facing each network. These differences include operating environment factors (such as vegetation management), network density and capitalisation policies.

Over time we continue to refine our benchmarking approach to improve its accuracy. In 2018 we completed a review of operating environment factors, and this year we are reviewing our approach to capitalisation.

We will continue to review the 0.75 comparison point as we refine our benchmarking techniques and better capture the individual circumstances of the NSPs.

[7] After taking into account operating environment factors.

2.4 Position

Having now considered the submissions we have received from stakeholders, for the reasons set out in this section, our position in this draft decision is to:

- retain the EBSS
- retain the current design of the scheme which allows networks to retain efficiency gains for six years and delivers a sharing ratio (currently around 20:80) that changes as the rate of return parameters change
- improve transparency about opex outcomes.

We will also continue to assess the appropriateness of the current 0.75 benchmark comparison as part of our benchmarking development work and report on outcomes in our annual benchmarking reports.

3 Capital Expenditure Sharing Scheme

3.1 About the CESS

How the CESS works

The CESS provides NSPs with an incentive to undertake efficient capex during a regulatory control period. It achieves this by rewarding NSPs that outperform their capex allowance and penalising NSPs that spend more than their capex allowance. The CESS also provides a mechanism to share efficiency gains and losses between NSPs and network users.

Without a CESS, a NSP will face incentives under the regulatory regime to achieve capex efficiencies, however, these incentives will decline over a regulatory control period. If a NSP makes an efficiency gain in the first year of a five-year regulatory control period any benefit will last for four more years before we update the RAB for actual capex. In the final year however, the benefit will be close to zero. This may lead to inefficient capex and inefficient substitution of opex for capex towards the end of a regulatory control period.

The CESS complements the rewards a NSP would already receive for an efficiency gain so the total benefit of an efficiency gain to a NSP will be the same in each year. The CESS also currently provides symmetric incentives in that the reward for an efficiency gain is equal to the penalty for an efficiency loss of the same quantum. The CESS was first implemented with a 30 per cent sharing ratio, which at the time, balanced the incentives between the CESS and the EBSS.

Rule requirements

How the CESS is currently applied is set out in the Capital Expenditure Incentive Guidelines.[8] The same framework that we applied in developing the Capital Expenditure Incentive Guidelines now also applies to any changes to the CESS that we may implement.

In summary, any changes we may make to the CESS must be:

- done so in a manner that will or is likely to contribute to the achievement of the NEO
- consistent with the capital expenditure incentive objective, taking into account the capital expenditure criteria, the capital expenditure factors and the capital expenditure sharing scheme principles.[9]

We must take into account:

- that NSPs should be rewarded or penalised for improvements or declines in the efficiency of capex
- that any rewards and penalties should be commensurate with the efficiencies or inefficiencies in capex, but rewards and penalties do not need to be the same
- the interaction of the CESS with any other incentives the NSP has to undertake efficient capex or opex
- the capital expenditure objectives, and if relevant, the operating expenditure objectives.

Position paper

Our preliminary views in the position paper were that the CESS should not be abolished because it has been successful in providing incentives to NSPs to incur efficient capex. However, we recognised that there may be a case to change the CESS to introduce a variable sharing ratio with

8 AER, *Better Regulation, Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013.

9 NEL, s 16(1)(a); NER, cll 6.4A, 6.5.7, 6.5.8A, 6A.5A, 6A.6.7(c) and 6A.6.5A.

a 30 per cent default rate that may be lowered to 20 per cent in certain circumstances. Specifically, we raised three options:

- Principles-Based Approach: assess a NSP against certain principles and criteria to determine whether we should apply a 20 per cent sharing ratio
- Bright-Line 10/10 Test: a 20 per cent sharing ratio would apply where a NSP underspent by more than 10 per cent in the previous regulatory control period and in its regulatory proposal sought an increase of more than 10 per cent compared to its actual expenditure in the previous regulatory control period, or
- Bright-Line Tiered Test: a 30 per cent sharing ratio would apply for underspending up to 10 per cent in the previous regulatory control period and a 20 per cent sharing ratio rate would apply to any underspending that exceeds 10 per cent of the forecast capital expenditure allowance.

We also recognised that there is a case to require NSPs to be more transparent about the reasons for differences between actual capex incurred and our approved forecasts in preceding regulatory control periods and proposed forecasts in regulatory proposals.[10]

Stakeholder forum

At the stakeholder forum on 26 August 2022, we also presented the option of a hybrid of the Principles-Based Approach and either the Bright-Line 10/10 Test or the Bright-Line Tiered Test. This would involve implementing either the Bright-Line 10/10 Test or the Bright-Line Tiered Test but also affording a NSP with an opportunity to justify why a 30 per cent sharing ratio (rather than a 20 per cent sharing ratio) should be applied to any underspend in excess of 10 per cent of the forecast capital expenditure allowance (Hybrid Test).

3.2 Stakeholder views

NSPs generally do not support varying the CESS on the basis that there is no case to do so. Conversely, consumer groups have expressed scepticism about whether, and the extent to which, consumers have benefited from the efficiency gains that the CESS has rewarded NSPs for. They have asked for more transparency about incentive payments and capex underspends, and for us to reconsider how the CESS is, or should be, applied.

In support of retaining the CESS as it currently is, the NSPs have submitted:

- the CESS has only been applied for one regulatory control period, and there is insufficient evidence that NSPs are over-forecasting and under-spending to receive rewards or otherwise gaming the regulatory process to justify changing it
- the analysis of HoustonKemp, as engaged by the Energy Networks Association, estimates that the CESS has delivered $2.9 billion in net benefits to consumers so far
- the real issue is about how we exercise our existing information gathering powers to address the information asymmetry between the NSPs, consumers and us, together with how we apply the Better Resets Handbook
- the current sharing ratio of 30 per cent is required to maintain a balanced incentive framework and is required to motivate management effort to seek further efficiencies and varying the CESS is not a proportionate response and may result in reducing consumer benefits.

However, were we to vary the CESS, the NSPs have submitted that we should:

[10] Ref Position Paper.

- implement the Bright-Line Tiered Test on the basis that it is objective, mechanistic, simple and predictable, as opposed to being uncertain, which is a characteristic that may arise under a principles-based approach
- consider whether 10 per cent is the appropriate threshold, and whether the threshold should account for the different circumstances of each NSP
- consider how varying the CESS may have any unintended consequence of punishing high-performing networks, discouraging underspending and delivering efficiencies
- revisit reducing the regulatory burden involved in complying with RINs and how NSPs should be required to transparently explain to consumers and us the reasons for any difference between actual capex and our approved forecast
- clarify how varying the CESS relates to achieving the capital expenditure incentive objective and how we have accounted for the capital expenditure share scheme principles in the NER.

Consumer groups have submitted:

- concerns about whether the capex underspends reported by networks represent genuine efficiency gains rather than the result of previous over-forecasting and capex deferrals
- more needs to be done to assess the results of the CESS (including by way of benchmarking against other countries where rate of return regulation is applied) and the networks should be required to explain, as part of their regulatory proposals, the difference between the previous forecast and actual expenditure in the previous regulatory control period
- we should encourage 'honest' forecast capex proposals, by reducing incentive payments to networks, or adjusting the sharing ratio between networks and consumers, in response to inaccurate forecasts
- there are sufficient mechanisms in the regulatory regime to encourage NSPs to incur efficient expenditure, and therefore, we should consider not applying the CESS at all.

Retail stakeholders have also raised concerns about the extent to which capex underspends represent genuine efficiency gains. They have also encouraged us to continue to improve how we apply the CESS.

A summary of submissions is set out in Appendix B of this Draft Decision.

3.3 Discussion

In this section, we set out our reasons for why we have arrived at the view that:

- there is a case to refine the incentives on NSPs to incur efficient capital expenditure during a regulatory control period, and
- the most appropriate way to refine the incentives on NSPs is to:
    - vary the CESS to implement the Bright-Line Tiered Test. This will apply
        - a 30 per cent sharing ratio for any underspend up to 10 per cent of the forecast capital expenditure allowance in the previous regulatory control period,
        - a 20 per cent sharing ratio for any underspend that exceeds 10 per cent of the forecast capital expenditure allowance in the previous regulatory control period, and
        - a 30 per cent sharing ratio for any overspend of the forecast capital expenditure allowance in the previous regulatory control period.

- assess whether the CESS is fit for purpose on a case-by-case basis in the context of our consideration of large transmission projects.

Case to refine incentives

In the position paper, we stated that there are two principal competing considerations concerning the CESS. Firstly, by its design, the CESS has the potential to reward a NSP for an underspend that is not the result of genuine efficiency gains. It is important to recognise that capital expenditure is generally less recurrent than operating expenditure, and accordingly, the benefit of the information we can derive from past capital expenditure about future capital expenditure is more limited. Secondly, since its introduction in 2013, the data we have collected so far strongly suggests that the CESS has worked well to provide incentives for NSPs to incur efficient capex.

The key question before us now is whether CESS rewards for underspends that are not genuine efficiency gains outweighs the incentives the CESS provides for NSPs to incur efficient capex. Or more pointedly, whether the CESS remains fit for purpose. This is the crux of the issue that arises between the competing views of NSPs and consumer groups regarding whether the CESS should be varied.

At the outset, it is important to recognise that this question can only be considered in the context of the regulatory regime that is prescribed in the NEL and the NER. This regulatory regime assumes that a forecast capex allowance that we determine in a regulatory determination, taking into account all the information available at the time, is the efficient and prudent amount of capex for a NSP to incur during a regulatory control period. The CESS works well if all underspends represent genuine efficiency gains. However, the extent to which an underspend that results in a reward payment to a NSP under the CESS genuinely reflects an efficiency gain, or is the result of forecast error, or in recent times a deferral due to the Covid 19 impact, can be difficult to ascertain.

This is due to the information asymmetry that exists between us, consumers and the NSPs. However, the level of information asymmetry between us and the NSPs inevitably reduces over time as we progressively better understand how each NSP operates in practice. That said, we recognise that a forecast capex allowance that we determine is efficient for a NSP to incur can never be a fully accurate representation of what a NSP might need to incur during a regulatory control period. Nor can such an allowance ever be said to be completely devoid of any forecast error. In practice, this means that the CESS will reward a NSP for an underspend irrespective of whether that underspend is the result of genuine efficiency gains or forecast error on our part. If a NSP is rewarded because of forecast error, this erodes the benefits of the CESS for consumers. At one extreme, if the forecast errors are large enough, consumers may be worse off because of the CESS: the quantum of the CESS payments to an NSP may exceed the efficiency gains made.

The extent to which forecast errors made on our part is a problem must be viewed in light of the improving overall accuracy of our forecasts over time and the reduction of the information asymmetry between us and the NSPs. Lower forecast error is the corollary of more accurate forecasts. This has been the result of our significant investment in the regulatory tools over the years that we use to assess and determine an NSP’s capex and opex forecasts, which are now well-developed. This includes:

- applying our replacement capex (repex) model to forecast replacement costs by asset category based on the age profile of assets, revealed replacement rates and revealed unit costs which allows us to benchmark and compare unit costs and replacement rates across NSPs
- using revealed unit costs to forecast connections and augmentation expenditure
- adjusting CESS payments for deferrals that we identify
- similar to opex, applying a base, step and trend approach for IT and vehicles
- subjecting particular capex project to detailed engineering reviews

- our guidelines on Distributed Energy Resources Integration expenditure, actionable integrated system plan projects and replacement modelling for transmission that emphasises the need for economic risk-based planning
- relying on market tested outcomes for major projects where possible (for example, for TransGrid's component of the South Australia to New South Wales interconnector, we used tendered costs as the basis for our forecast).

Our Better Resets Handbook further supplements these tools. The Better Resets Handbook provides reputational incentives for NSPs to improve their processes and regulatory proposals by establishing principles for good regulatory proposals and better consultation with consumers. In particular, the Better Resets Handbook sets out our clear expectations on the process, and what constitutes and is required, of a proper proposed capex forecast. Meeting these expectations is part of reducing the level of information asymmetry that exists between the NSPs and us.

The improvements in the accuracy of our forecasts over time is shown in Figures 5 and 6.

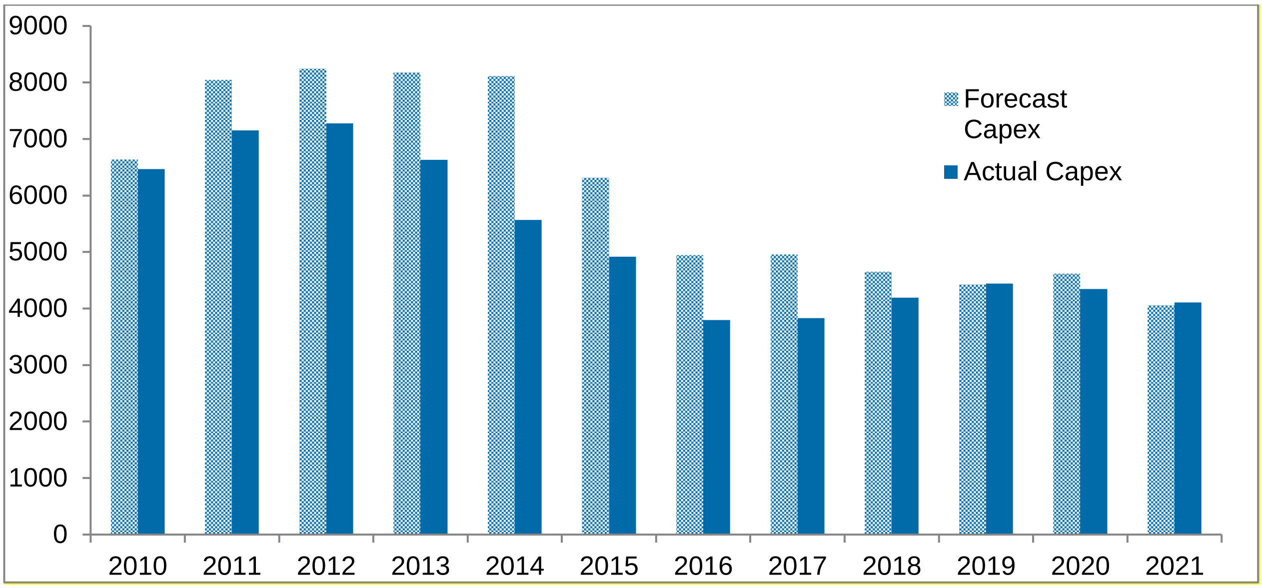
Figure 5 shows forecast and actual aggregate electricity distribution capex by year from 2011 to 2021. Capital expenditure peaked in 2012, fell substantially over the next four years to 2016 and has been relatively stable since then. Forecast error fell over the period and has averaged at 5 per cent over the four years from 2018 to 2021.

Figure 6 compares the level of aggregate distribution and aggregate transmission capex under or overspending over the last two full regulatory control periods, and the current regulatory control period.[11] It shows that NSPs underspending relative to our forecasts has reduced significantly over the three regulatory control periods. For DNSPs, the average underspend has fallen from around 18 per cent in the first regulatory control period to around 7 per cent now.

For TNSPs, an underspend of some 28 per cent in the first regulatory control period is now an overspend of around 5 per cent (despite transmission being generally harder to forecast because it is less recurrent and has more project 'lumpiness' with significant major projects including new interconnectors).

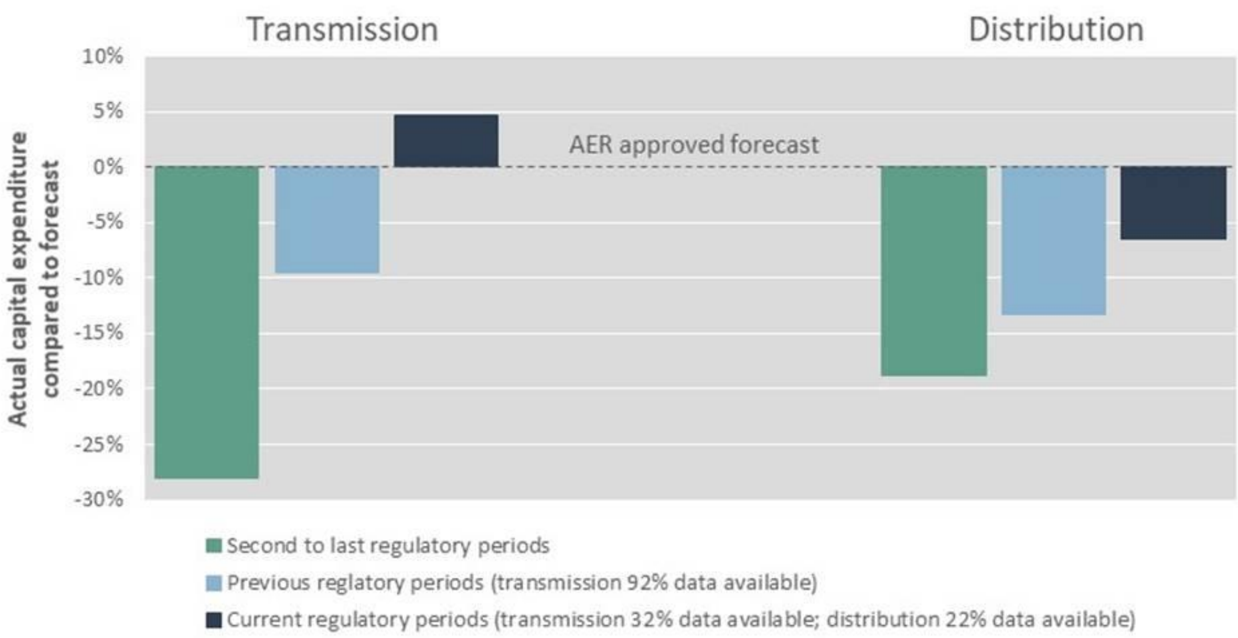
[11] For DNSPs, the current regulatory period is 2021-25 for VIC, QLD and SA, and 2020-24 for NSW and ACT. The previous regulatory control period is 2016-20 for VIC, QLD and SA, and 2015-19 for NSW and ACT. The second to last regulatory control period is 2011-15 for VIC, QLD and SA, and 2010-14 for NSW and ACT.

Figure 5: Forecast and actual electricity capital expenditure by year ($m 2021)



Source: AER data

Figure 6: Actual capital expenditure compared to forecast



Source: AER data

However, whilst the accuracy of our forecasts has improved over time, this improvement has not been equally realised for each NSP. This can be seen in Table 2, which sets out each DNSP's underspending:

- in the last full regulatory control period (column 2)
- compared to our final decision for the previous regulatory control period (column 3)
- compared to how much the network proposed in the following regulatory control period (column 4).

Table 2: Capital expenditure compared to AER forecast by distribution network

DNSP	Underspend in previous regulatory control period	Final decision compared to actuals in previous regulatory control period	Initial proposal compared to actuals in previous regulatory control period
AusNet Services	-15%	-18%	-14%
CitiPower	-32%	3%	49%
Jemena	-23%	9%	7%
Powercor	-14%	0%	24%
United Energy	-22%	17%	58%
SA Power Networks	-16%	-5%	2%
TasNetworks	7%		29%
Evoenergy	2%	-8%	-3%
Ausgrid	-16%	-5%	6%
Endeavour Energy	-6%	9%	8%
Essential Energy	-16%	-6%	-5%
Energex	-12%	-21%	-20%
Ergon Energy	-3%	-24%	-8%
All distribution networks	-13%	-18%	-14%

Notably, there is a wide disparity between networks in their initial proposals. Column 4 shows that some networks proposed a significant step up in capex compared to what they actually incurred in the previous regulatory control period, and similarly that our final decision was significantly lower than some of the networks' initial proposals (column 4).

For example, some of the Victorian electricity distribution networks underspent in the previous regulatory period and then requested a step up in capex, while AusNet Services underspent its capex in the previous regulatory period and then proposed a further step down in spending. AusNet Services went through the NewReg trial and consulted with its customers in forming its regulatory proposal. The end outcome was positive for customers on its network.

Our experience in making the final decisions for Victorian DNSPs suggests that we have the tools available to provide reasonable capex forecasts. However, the Victorian experience also highlights variability in the quality of proposals and the level of consumer engagement undertaken in developing the proposals.

In this context, the purpose of the CESS is to provide NSPs with an incentive by rewarding them for being even more efficient in incurring capital expenditure than our forecast allowance assumes, and conversely, a penalty if a NSP is not as efficient as our forecast allowance assumes. In other words, the CESS encourages a NSP to underspend against our forecast allowance.

Incentives to outperform forecasts are consistent with the capital expenditure sharing scheme principles and the capital expenditure incentive objective in the National Electricity Rules. The capital expenditure sharing scheme principles provide that a NSP should be commensurately rewarded or penalised for improvements or declines in efficiency of capital expenditure whilst allowing for such rewards or penalties to differ.[12] The capital expenditure incentive objective is aimed at only including prudent and efficient capital expenditure (that which reasonably reflects the capital expenditure criteria) in the regulatory asset base.[13]

As stated above, the key question before us now is whether CESS rewards for underspends that are not genuine efficiency gains outweigh the benefits to consumers from incentives the CESS provides for NSPs to incur efficient capex. If the answer to the question that we have posed is ‘no’, then any part of a reward provided by the CESS that represents a benefit for an underspend that is actually not a genuine efficiency gain, has been outweighed by the overall efficiencies achieved which consumers benefit from. Conversely, if the answer to the question is ‘yes’, then the CESS has not achieved its objective. This means that the value of the reward provided by the CESS is not outweighed by the value of the efficiencies realised by an NSP.

In our view, there is a real prospect that the answer is yes. Recent expenditure outcomes in Victoria and South Australia have revealed that more can be done to reduce the level of forecast error, and in turn, the possibility of an NSP being rewarded for non-genuine efficiency gains.

There are several ways we can reduce forecast error. As discussed above we have invested in our expenditure assessment toolkit, and we have improved engagement between NSPs and consumers through our Better Resets Handbook.

This draft decision proposes two additional measures to improve forecast outcomes. The first is to improve transparency about variations between operating and capital expenditure outcomes and forecasts. Improved transparency will help consumers understand NSP proposals and identify step changes in forecasts compared to historic outcomes. In turn this will assist consumers in their engagement with the NSPs. It will also assist the AER in assessing regulatory proposals. Details are provided in section 5.

The second measure proposed in this draft decision is to introduce a ‘tiered’ incentive rate, which varies the CESS to apply a lower sharing ratio when the gap between actual and forecast capital expenditure is high. The cut off we have adopted in this draft decision is 10 per cent. That is a lower sharing ratio applies for outperformance above 10 per cent.

Applying a tiered incentive rate recognises the benefits of retaining the existing 30 per cent sharing ratio in some form, given the efficiencies it has driven to date. However, when the gap between actual and forecast capital expenditure is high, there is a real prospect of non-genuine efficiency gains due to forecast error. The tiered rate proposed will reduce incentives for NSPs to overstate their expenditure requirements by reducing CESS payments (compared to the current CESS) when outperformance is high. This increases the likelihood that NSPs will provide realistic and efficient forecasts as part of a regulatory proposal, and in turn reduces the risk of forecast error and underspending that reflects non-genuine efficiency gains.

We consider that the improved capital expenditure forecasts that flow from these initiatives are in the long-term interests of consumers.

Options for varying the CESS and reducing information asymmetry

As we noted above, we have raised the following options to vary the CESS:

[12] NER, cll 6.5.8A(c) and 6.5.8A(d).

[13] NER, cll 6.4A(a) and 6.5.8A(b).

- the Principles-Based Approach
- the Bright-Line 10/10 Test
- the Bright-Line Tiered Test
- the Hybrid Test.

Of these options, for the following reasons, our position in this draft decision is to vary the CESS to implement the Bright-Line Tiered Test. The Bright-Line Tiered Test applies:

- a 30 per cent sharing ratio for any underspend up to 10 per cent of the forecast capital expenditure allowance in the previous regulatory control period
- a 20 per cent sharing ratio for any underspend that exceeds 10 per cent of the forecast capital expenditure allowance in the previous regulatory control period
- a 30 per cent sharing ratio for any overspend of the forecast capital expenditure allowance in the previous regulatory control period.

Firstly, the principles of predictability, certainty, simplicity and minimising regulatory burden have been raised by the NSPs. We recognise that the Principles-Based Approach involves us exercising our discretion against qualitative criteria to determine whether any underspend would be rewarded by a 30 or 20 per cent sharing ratio. This would introduce a degree of uncertainty about how the CESS would be applied in practice, and has the potential to undermine the investment certainty.

Secondly, the Bright-Line 10/10 Test links the expenditure performance of a NSP between two regulatory control periods by reducing the sharing ratio from 30 to 20 per cent if two conditions are met. Namely, if the NSP underspent by more than 10 per cent in the previous regulatory control period and seeks an increase of more than 10 per cent in its regulatory proposal for the subsequent regulatory control period. In our view, such a mechanism would not aptly account for the legitimate requirements for material changes in capital expenditure requirements that may arise during or between regulatory control periods which are beyond the control of a NSP, without introducing significant regulatory complexity and unintended consequences.

Most NSPs have made similar submissions advocating against us implementing the Bright-Line 10/10 Test. In particular, NERA, engaged by the Energy Networks Association, submitted:

> *By linking the forward looking incentive rate to performance in the previous regulatory period and whether the NSP has requested a step-up in their forward looking capex allowance, this option implicitly assumes that capex requirements will be relatively stable over time. That is to say, it assumes future capex needs are related to past capex needs. This may only be true for a small subset of recurring capex. Therefore, this option is vulnerable to periods of significant change where history may be a less useful guide for future requirements.*[14]

We generally agree with the conclusion that NERA has arrived at in advocating against the Bright-Line 10/10 Test. However, we do not agree with the observation that past capex needs can only inform a small subset of recurring future capex. The extent to which past capex cannot usefully inform forecast capex can only be identified at the time of a regulatory proposal, and will usually relate only to NSPs meeting capex requirements for reasons outside their control.

Thirdly, the Bright-Line Tiered Test is certain and predictable. It is not affected by the uncertainty of the Principles-Based Approach nor the unintended consequences that may arise from the Bright-Line 10/10 Test. The NSPs have made similar submissions in support of us implementing the Bright-Line Tiered Test were we to vary the CESS.

Applying a lower sharing ratio of 20 per cent to any underspend that exceeds 10 per cent will strengthen the incentive for NSPs to submit forecast capital expenditure proposals as part of a

[14] NERA Economic Consulting, *Review of the AER's potential variable rate CESS options - Energy Networks Australia*, 9 September 2022, p. 7.

regulatory proposal that are less likely to be over-stated. In turn, this has the effect of reducing the level of forecast error in a forecast capital expenditure allowance that we may determine as part of a regulatory determination.

Further, the Bright-Line Tiered Test that we intend to implement is not symmetric. The 20 per cent sharing ratio will not be applied to any overspend in excess of 10 per cent of the forecast capital expenditure allowance. Our reasons for this are:

- As we have noted, consumers are concerned that the CESS encourages NSPs to over-state their forecast capital expenditure requirements. Despite improvements in our assessment toolkit and stakeholder engagement, a level of information asymmetry between us, consumers and the NSPs remains. Therefore, the risk of over forecasting capex requirements remains higher than under forecasting. Given this, applying the Bright-Line Tiered Test asymmetrically has the effect of providing an offset to potential asymmetry in forecast error.
- Generally, the level of information asymmetry that exists between NSPs, consumers and the AER is greater in setting capex forecasts than it is in setting opex forecasts. This arises because capex is generally less recurrent than opex (particularly in transmission). Accordingly, we consider it appropriate to have symmetry in the EBSS and asymmetry in the CESS.
- The approach proposed is consistent with the overall design of the regulatory regime that is prescribed in the NER. For example, the NER already allows for us to undertake an ex-post review to exclude overspends that we consider are not efficient. The ex-post review is itself asymmetric, as there is no ability for us to undertake an ex-post review of an underspend.

Finally, we agree with the submissions of NSPs that to further provide an opportunity for a NSP to justify why any underspend in excess of the 10 per cent threshold (being the Hybrid Test) would invite the same uncertainty that arises under the Principles-Based Approach and undermine the certainty and predictability of the Bright-Line Tiered Test.

That said, the NSPs have raised the following issues with the Bright-Line Tiered Test:

- the Bright-Line 10/10 Test may blunt or discourage a NSP to achieve further or large efficiency gains that may exceed the underspend threshold of 10 per cent
- whether the underspend threshold of 10 per cent is appropriate, having regard to differing sizes of NSPs, and the lumpy nature of transmission capex.

Firstly, in our view, the risk of discouraging genuine capital expenditure efficiency gains that may exceed the underspend threshold of 10 per cent this risk, albeit possible, is unlikely to occur in practice. This is because NSPs will continue to be rewarded for any such underspends, by applying a lower sharing ratio of 20 per cent. Were we to apply a zero or much lower sharing ratio, this may be a material concern. However, this is not the case here. A 20 per cent sharing ratio still provides a material reward to NSPs for achieving genuine efficiency gains.

Secondly, an underspend threshold of 10 per cent is appropriate. This threshold is broadly consistent with historical underspending trends across NSPs. The gap between forecasts and outcomes has averaged 11.7 per cent since 2015 and 10 per cent since 2016 for electricity distributors. As shown in Table 3, in recent years forecast accuracy has improved. Since 2018, the underspend has averaged 5 per cent. In this context a 10 per cent threshold provides a meaningful materiality cut-off and is only likely to affect a limited number of ‘outlier’ NSPs.

Table 3: Capex compared to AER forecast, electricity distribution

Year	2016	2017	2018	2019	2020	2021
Percentage difference between forecast and actual capex	-23%	-23%	-10%	0%	-6%	1%

Souce: AER data

Further, it would not be appropriate to now apply a variable threshold that may differ depending on the size or circumstances of an individual NSP. Whilst we recognise that the differing size and circumstances of a NSP may call into question the appropriateness of applying a 10 per cent threshold[15], to now prescribe a variable threshold to comprehensively deal with the differing circumstance of each NSP would introduce a substantial amount of complexity. This would be at odds with the certainty and predictability that NSPs seek (and of which, we agree with).

For the reasons outlined above, we have arrived at our position to vary the CESS to implement the Bright-Line Tiered Test. The Bright-Line Tiered Test provides for certainty and predictability in its application. The risk of deterring a NSP from realising genuine efficiencies in excess of the 10 per cent threshold is unlikely to be material.

As noted above, there are elements of capex that are not recurrent and harder to forecast using the revealed cost model. This is particularly true for large transmission projects. We intend to determine whether it is appropriate to apply the CESS to large transmission projects as part of assessing contingent project and regulatory reset proposals. In so doing, we would take into account, among other things, a NSP's forecast capital expenditure proposal and the degree of forecasting risk.[16]

3.4 Position

Having considered the submissions we have received from stakeholders, for the reasons set out in this section, in this draft decision our position is to:

- vary the CESS to implement the Bright-Line Tiered Test, which will apply:
  - a 30 per cent sharing ratio for any underspend up to 10 per cent of the forecast capital expenditure allowance in the previous regulatory control period
  - a 20 per cent sharing ratio for any underspend that exceeds 10 per cent of the forecast capital expenditure allowance in the previous regulatory control period
  - a 30 per cent sharing ratio for any overspend of the forecast capital expenditure allowance in the previous regulatory control period.
- require an NSP, as part of its regulatory proposal for a forthcoming regulatory control period, to transparently explain the reasons for differences between actual capex incurred and our approved forecast in the then current regulatory control period a proposed forecast for a forthcoming regulatory control period the subject of a regulatory proposal
- determine whether the CESS should be applied to large transmission projects as part of assessing contingent project and regulatory reset proposals.

[15] For example, accurately forecasting augmentations for transmission networks, and identifying whether efficiencies are realised, is a more challenging task than forecasting the often-recurrent categories of capital expenditure faced by distribution networks

[16] Taking into account, for example, the extent to which a project is already outsourced and subject to contract terms.

4 Service Target Performance Incentive Scheme

4.1 About the STPIS

We provide electricity NSPs with incentives for maintaining and improving network performance. It does this by rewarding networks that outperform service performance targets and penalising networks that underperform service performance targets.

The STPIS balances the cost cutting incentives in the EBSS and CESS. The objective is to drive expenditure reductions through efficiency gains rather than at the expense of service levels to customers.

There are separate service performance schemes for electricity distribution and electricity transmission. There are no schemes for gas networks.

For electricity distribution the focus is the frequency and duration of interruptions to supply. Reliability is measured by a combination of System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Momentary Average Interruption Frequency Index (MAIFI). This is measured for each segment of the network — CBD, urban and rural.

Reliability targets are typically based on the level of reliability achieved by a network over a recent period. These targets are then updated every 5 years as part of the regulatory determination process.

The rewards for improving reliability (and the penalties for declines in reliability) are based on the value that customers place on improved reliability. We undertook a review of the value of customer reliability in 2019 and use the outcome in setting the STPIS targets.

Electricity transmission networks typically have higher levels of redundancy and reliability than electricity distribution. In this context, the focus of the STPIS for electricity transmission focuses on the impact of outages. This scheme has 3 components — the service component, market impact component, and network capability component:[17]

- *Service component.* The service component provides a reward or penalty of plus or minus 1.25 per cent of the maximum allowed revenue based on the number of unplanned network outages and how quickly unplanned outages are restored.
- *Network capacity component.* The network capability component provides incentive payments to transmission NSPs to undertake small, high net benefits projects. These projects are expected to have a short payback period and deliver improvements in the capability of the transmission network at times when it is most needed.
- *Market impact component.* The market impact component provides an incentive to transmission NSPs to minimise the impact of transmission outages that affect wholesale market outcomes. The market impact component measures performance against the market impact parameter, which is the number of dispatch intervals where an outage on the transmission network results in a network outage constraint[18] with a marginal value greater than $10/MWh (known as the ‘MIC count’).[19]

17 AER, *Final – Service Target Performance Incentive Scheme,* October 2015, cl. 2.2(a).

18 Network outage constraints are constraint sets that are applied in AEMO's market systems to manage power flows during outages so that the power system remains secure during an outage.

19 AER, *Final – Service Target Performance Incentive Scheme,* October 2015, Appendix C.

4.2 Stakeholder views

Submissions focus on transmission and the Market Impact Component (MIC) of the STPIS.

The transmission NSPs propose a review of the MIC as a matter of urgency on the basis that the method for setting performance targets is no longer fit purpose.

The current method sets future targets based on historic data. However, high investment in variable renewable energy generation is creating greater and more widespread congestion, significantly increasing network constraints above historical averages. The networks consider that they are being penalised for changes in the generation mix rather than their performance. They propose a review of the MIC to consider target setting (use of historic averages) and the behaviour to be incentivised (scheduled verses dynamic responses to emerging congestion).

On the distribution side, networks consider the STPIS fit for purpose and make some suggestions for improving the scheme:

- The ENA notes that STPIS rewards are based on the value customers place on improved reliability and note that consumers retain 78 per cent of any improvements.
- Citipower, Powercor and United Energy suggest reviewing the STPIS in light of more severe weather events, with a view to revising the approach to major event days.
- AusNet notes that the STPIS does not recognise export services, and notes that the AER is addressing this in the context of its review of incentive arrangements for export services. AusNet considers there is a case for adding export services incentives into the STPIS.

The CCP notes improved service performance over time but recommends rebalancing the STPIS so that it is less reliant on incentive payments and more reliant on penalties.

Red Energy recommends abolishing the Demand Management Incentive Scheme and the Demand Management Innovation Allowance. Both schemes provide incentive payments to electricity distribution service providers to undertake projects which reduce or shift customer demand in order to avoid or defer network augmentation.

4.3 Discussion

The focus of submissions is the transmission STPIS. All the transmission NSPs are seeking a review of the MIC. They consider the approach to setting future performance targets is no longer fit purpose given substantial changes in mix and location of new generators across the NEM.

We think the MIC plays an important role in minimising market disruptions for generators and the scheme is working to incentivise management of network congestion as designed. While we observe increases in the number of constraints, the increased counts will provide signals to the transmission networks to either change their network management or undertake capital works to address network congestion.

At the same time the data shows increasing congestion because of the transition to renewables. Increasing congestion risks penalising TNSPs for factors which our out of their control.

Targets for the MIC are set through the revenue determination process for each transmission NSP. The target is calculated by averaging the median 5 of the last 7 years of annual performance measure data.[20] Service provider receive a reward or penalty of up to plus or minus 1 per cent of the maximum allowable revenue for the relevant calendar year. Because solar and wind

[20] The target will be calculated from the average of the 5 values remaining from the last 7 years of annual performance measure data, excluding the largest and smallest annual values.

generation investment is adding to congestion, historic performance measures are no longer an accurate indicator of likely future performance.

In addition, several reviews that will affect the regulation of transmission networks are underway. These include the Energy Security Board's post-2025 Market Design, AEMC's Investigation into system strength frameworks in the NEM, the outcomes of the Coordination of Generation and Transmission Investment review, and the general implementation of actionable projects under AEMO's integrated system plan.

We consider it prudent to review the MIC in light of increasing transmission congestion and the transmission reviews currently underway. Our draft decision is to conduct a review of the MIC starting in the second half of 2023, which would allow any revisions to be picked up in time for the next Queensland and South Australian transmission reset processes.

In the meantime, we will continue to work with transmission network providers on a case-by-case basis to determine appropriate performance targets within each revenue determination.

Submissions on the distribution STPIS generally see it as fit for purpose, though the CCP recommends less reliance on incentive payments and more on penalties, while the distribution networks raised some implementation issues.

Over time the STPIS has contributed to improvements in the number and duration of distribution outages with the scheme. Between 2006 and 2020, the average number of interruptions per customer per year declined by 0.68, or 38 per cent. Similarly, between 2006 and 2020, the average duration of outages reduced by 26 minutes or 18 per cent.

We will consider further Ausnet's submission that STPIS be extended to export services as part of our review of incentive arrangements for export services. We note that our draft report does not recommend extending the STPIS to export services because of differences in underlying incentives and network conditions and limited evidence across distribution networks that customers are receiving export services that do not meet their expectations. In addition, we intend to introduce a new small-scale incentive scheme (SSIS) to permit DNSPs to propose bespoke incentive schemes in their regulatory proposals. Further, we note the DMIA and DMIS are designed to incentivise DNSPs to undertake demand management projects that are efficient and contribute to resolving network constraints. In this way, demand management projects can reduce, delay, or even avoid the need to install, replace or upgrade network assets. Recent changes to the NER confirm that the DMIA and DMIS do not apply exclusively to the management of demand for consumption services, and so DNSPs are permitted to propose projects and associated expenditures related to the management of demand for export services.[21]

Our draft decision is to retain the distribution STPIS in its current form:

- the scheme has successfully contributed to improved service performance
- we reviewed the scheme in 2018 and the value of customer reliability in 2019
- we consider the approach of linking performance incentives to the value of customer reliability remains appropriate.

Submissions commented on three other aspects of the STPIS, the Network Capability Incentive Parameter Action Plan (NCIPAP), the Demand Management Incentive Scheme (DMIS) and the Demand Management Innovation Allowance (DMIA).

[21] For further detail see: *AER, Incentivising and measuring export services – draft report*, November 2022.

The NCIPAP scheme incentivises operational expenditure and minor capital expenditure that results in:

- improved capability of those elements of the transmission system most important to determining spot prices, or
- improved capability of the transmission system at times when transmission network users place greatest value on the reliability of the transmission system.

The scheme is based on business case analysis and outcomes are generally considered project by project.

We consider there is a case to review the NCIPAP when we undertake the MIC review. While the scheme has generated several projects and has encouraged TNSPs to think about non-network initiatives to address transmission capability, circumstances have changed. AEMO and the TNSPs now work more closely together on transmission planning including in developing options and undertaking cost-benefit assessments. Given the new planning arrangements there is a question about whether the network capacity scheme is still required. We also note the scheme is administratively complex for all parties. Our position is to review the NCIPAP scheme alongside the MIC review.

Red Energy suggests discontinuing the DMIS and DMIA schemes. The DMIS incentivise DNSPs to undertake efficient expenditure on non-network options focusing on demand management (DM). The DMIA funds DNSPs to undertake projects which reduce or shift customer demand in order to avoid or defer network augmentation.

The DMIS and DMIA are relatively recent initiatives (introduced in 2017) and were considered as part of a STPIS review in 2018. To date the schemes have incentivised several projects and, as noted above, we are proposing to extend application of the schemes to export services.[22] We are not proposing further review the schemes at this point.

4.4 Position

Our position in this draft decision is to:

- retain the distribution STPIS
- retain the service component of the transmission STPIS
- undertake a review of the STPIS MIC starting in the second half of 2023 and completed in time for the next Queensland and South Australian transmission resets
- review the Network Capability Incentive Parameter Action Plan (NCIPAP) as part of the STPIS MIC review.

22 AER consultation paper: Incentivising and Measuring Export Service Performance, August 2022

5 Improved transparency

As we have noted above, our review of the EBSS, the CESS and the STPIS has identified an opportunity for us to improve the transparency of, and the reasons for, differences between our expenditure forecasts and the actual expenditures incurred by NSPs during a regulatory control period. Improved transparency will better inform consumers and us about the extent to which any underspends incurred by a NSP do indeed reflect genuine efficiency gains.

In our view, a clear case exists for NSPs to be more transparent about the reasons for any differences between actual capex incurred and our approved forecasts in a given regulatory control period. In addition to the criteria set out in the Better Resets Handbook about what we expect from a robust capex forecast in a regulatory proposal, there is also a clear case for NSPs to explain how actual capex outcomes in one regulatory control period relate to any proposed forecasts in a regulatory proposal for the following regulatory control period.

In its submission, the CCP proposes new requirements for NSPs to explain the difference between forecasts and outcomes. It recommends:

> Recommendation: Businesses should be required to provide a credible narrative to explain why their outturns differed from regulatory decisions. This would go some way towards giving stakeholders better information to support their understanding regarding whether and to what extent incentive payments are justified. We recommend that these narratives should be published as part of the networks' price submissions. They should be subject to public scrutiny, and should be used to judge the quality of the network's proposal for the next regulatory period.
>
> A good narrative regarding what has happened in the current regulatory period and how that has informed what is being proposed for the upcoming regulatory period would confirm the network's commitment to customers, and its credibility as an efficient manager of network services.

Increased transparency will help consumers and us to better assess efficiency performance and understand forecast expenditure proposals. It may also support the reputational incentives faced by networks. Our preliminary position is to revisit how we use our information gathering powers to require NSPs to provide:

- clear explanations for why actual expenditure incurred by a NSP departs from a forecast capex allowance we have determined in a given regulatory control period and how any such departure is to be explained in light of a capex proposal in a regulatory proposal for the following regulatory control period
- where capex projects or programs have been deferred from one regulatory control period to the next, the reasons why
- the extent to which changes beyond the control of an NSP, including regulatory obligations, customer demand, and environmental issues may be relevant.

We will revisit these matters as part of the Networks Information Requirements Review that we are currently conducting, which commenced on 23 March 2022,[23] and our consultation from March 2023 on the regulatory information notices (RINs) for the forthcoming regulatory proposals for South Australia Power Networks (SAPN), Ergon Energy and Energex on 31 October 2023.

These consultation processes will also provide the NSPs and us an opportunity to engage with consumer groups to properly identify the information we should seek from NSPs to better understand and improve the transparency about differences between our expenditure forecasts and the actual expenditures incurred. Our intention is for NSPs to provide a narrative, as recommended by the CCP, that explains differences between capex outcomes and forecasts in a way that both comprehensive and accessible to stakeholders.

[23] AER, *Network Information Requirements Review: Discussion paper*, March 2022.

The proposed transparency requirements are consistent with the expectations we set out in our Better Resets Handbook.

To this end, we propose to include a requirement in the RINs for a NSP to provide detailed information on the factors that have materially impacted the level of actual expenditure incurred in comparison to the forecast expenditure allowance that we approved for a regulatory control period. We will also be requiring the detailed information to address any relevant underlying circumstances, and any changes in the assumptions that were made and underpinned the forecast expenditure allowance. Finally, we are also considering staging these requests for information. For example, to require SAPN, Ergon Energy and Energex to provide by:

- 31 January 2024, detailed information for the first three regulatory years of the 2020-25 regulatory control period
- 31 October 2027, detailed information for each regulatory year of the 2020-25 regulatory control period and the first two regulatory years of the 2025-30 regulatory control period.

6 Draft Decision

For the reasons discussed above, our position in this draft decision is to:

- retain the EBSS as is
- vary the CESS by implementing a tiered arrangement, with a 30 per cent sharing ratio for any underspend up to 10 per cent of the forecast capital expenditure allowance, a 20 per cent for any underspend over 10 per cent and a 30 per cent sharing ratio for any overspend
- retain the distribution STPIS as is
- retain the service component of the transmission STPIS as is
- undertake a review of the MIC in the second half of 2023
- improve the transparency of, and the reasons for, differences between our expenditure forecasts and the actual expenditures as part of the Networks Information Requirements Review and the forthcoming RINs we will serve on SAPN, Ergon Energy and Energex.

Varying the CESS will require amending our Capex Incentive Guideline. We seek views on when the new provisions should commence and specifically whether the revised Capex Incentive Guideline should apply to the upcoming NSW, ACT, NT and Tasmanian resets.

APPENDIX A: Summary of stakeholder views on the EBSS

Stakeholder	Retain EBSS	Vary sharing ratio?	Key points
Ausgrid	✓	X	1. Incentives including the EBSS are working well 2. Forecasting tools such as benchmarking and guidance notes for ICT and DER contribute to improved forecasts
AusNet services	✓	?	1. Case to align EBSS and CESS at 30:70 but practical issues with implementing this change 2. Concerned about benchmarking and its use in setting the opex base given the AER's approach to capitalisation
Citipower, Powercor & United Energy	✓	X	1. EBSS fit for purpose 2. Case to see impact of Better Resets Handbook before making changes
Consumer Consultative Panel	?	?	1. Concern about opex forecasts and the time lag before consumers benefit from the EBSS 2. Notes that the EBSS is an information rent and not an efficient cost per se 3. Recommends either ▪ a higher efficiency (or productivity) factor than the current 0.5 per cent per annum ▪ or a link between the EBSS and efficiency factor with a higher EBSS sharing ratio for businesses proposing higher efficiency factors ▪ and improved transparency about opex outcomes
Endeavour Energy	✓	X	1. Endeavour has made substantial improvements in efficiency in response to the incentive regime 2. Further opex improvements will be harder in future as opportunities to address organisational and structural inefficiencies are exhausted 3. Improvements in consultation and engagement processes, the productivity factor and other changes makes it harder to over-forecast
Energy Queeensland	✓	X	1. EBSS remains fit for purpose 2. There is merit in reviewing the AER's approach to making efficiency adjustments to base opex (using benchmarking) as moving away from revealed costs distorts the operation of the EBSS
Energy Networks Australia	✓	X	1. EBSS is operating as intended, is fit for purpose and has benefited consumers by delivering lower network prices and improved service quality 2. Houston Kemp report estimates EBSS gains to consumers of approx. $7 billion compared to EBSS costs of approx. 3 billion 3. There are strong safeguards on opex forecasts including the Better Resets Handbook and enhanced AER expenditure forecasting techniques 4. Recent inclusion of a productivity factor means forecasts factor in expected productivity improvements 5. At this point there is no evidence that the gap between the EBSS and CESS is distorting behaviour:

			▪ discretion in allocation of costs between opex and capex is marginal as most expenses fall clearly into one category or another ▪ if there are any material shifts they will become evident in regulatory reporting
Essential Energy	✓	✓	1. Weakening incentives is not in the long-term interest of consumers 2. EBSS should be independent of the rate of return and aligned with 30:70 split of CESS 3. The submission includes suggestions for an alternative mechanism to the EBSS to achieve a 30:70 split
Evoenergy	✓	X	1. EBSS is fit for purpose
Jemena	✓	X	1. EBSS is fit for purpose and incentives are balanced over the longer term
Network of Illawarra Consumers of Energy (NICE)	X	?	1. There is a case for removing the EBSS noting that the same outcome can be achieved as the EBSS if the carry-over is removed but the base year is set on a five-year average of opex 2. Recommends changes to opex forecasting with ‘zero adjustment’ for the most efficient firms and progressively higher negative trend adjustments the further the NSP is from the efficiency frontier 3. If EBSS is retained, the 6 year of retained benefits is appropriate and it is appropriate for the sharing ratio to vary with the time value of money 4. The scheme should not be symmetric, higher penalties should apply for overspending 5. Preference is for rule changes to allow performance-based regulation based on benchmarking
SA Power Networks	✓	X	1. No case for change to the EBSS has been made 2. At this point there is no evidence that the gap between the EBSS and CESS is distorting behaviour
Red Energy	?	?	1. The incentive schemes should be refined so that they only reward genuine efficiency gains
Origin Energy	✓	X	1. The EBSS is largely working as intended given its reliance on revealed costs 2. There is scope to review the approach to forecasting including the use of benchmarking
TasNetworks	✓	X	1. Concerns about the incentive schemes relate to forecasts rather than the schemes themselves 2. Improvements in forecasting processes, including guidance notes and increased and more effective stakeholder engagement reduce risk of forecasting error
Transgrid	✓	✓	1. Supports maintaining existing incentives including the EBSS 2. EBSS should be aligned with the 30:70 split of CESS 3. The submission includes suggestions for an alternative mechanism to the EBSS to achieve a 30:70 split

APPENDIX B: Summary of stakeholder views on the CESS

Stakeholder	Retain CESS as is	If the CESS is to be varied, option preferred	Key points
Ausgrid	✓	Bright Line Tiered Test	3. Adopts the ENA's submission. 4. Case to change CESS not made out. 5. Timing of capex within a regulatory control period is not driven by the CESS. 6. Does not support a flexible CESS, which may reduce the incentive to invest in long-term efficiencies.
AusNet services	✓	No preference expressed	1. CESS should not be modified. 2. Does not support applying a bespoke or flexible version of the CESS. Particularly given the relatively short application of the CESS; unintended consequences and investment uncertainty. 3. Concerns of over-forecasting should be addressed by reviewing the AER's toolkit, rather than adjusting expenditure incentives.
Citipower, Powercor & United Energy	✓	Bright Line Tiered Test	1. Case to change CESS not made out. Further evidence is required, and the outcomes of the AER's toolkit and Better Resets Handbook should be first observed. 2. Core issue is information asymmetry; supports greater transparency; AER already has extensive information gathering powers. 3. Bright Line Tiered Test is objective but blunts the incentive to achieve large efficiencies. 4. The underspend threshold should be 15 per cent.
Consumer Consultative Panel	X	No preference expressed; position to reconsider the CESS generally	1. Concerned about whether the CESS represents good value for money for consumers. In particular, whether CESS payment reflect genuine efficiency gains, deferrals, switching between capex and opex, forecast error on the part of the AER. 2. Out-turn capex is not necessarily efficient, particularly where it is one-off in nature. 3. CESS payments are not linked to the quality of services delivered or the efficiency of those services. 4. The 30 per cent sharing ratio is poorly established and arbitrary. 5. CESS payments are not required for NSPs to deliver services, and are therefore not necessary nor an efficient cost to be recovered from consumers. 6. CESS payments may be rewarding NSPs for the AER's forecast errors. CESS payments may be justified if they result from lower spending due to productivity improvements that were unforeseeable at the time of the AER's revenue determination or would not have been found without the CESS being in place. 7. There is a widening gap between NSPs' regulatory proposal and the AER's capex allowances, which is explained by the CESS providing an incentive for NSPs to overstate their capex requirements. 8. The fact NSPs enthusiastically support the CESS (and the EBSS) suggests the schemes are aligned to the NSPs' financial interests. 9. Supports further transparency, so long as the AER consults on how it will use that information.

			10. Lowering the sharing ratio in the CESS does not address the incentive for NSPs to overstate their capex requirements. 11. Applying the proposed changes to the CESS symmetrically has the perverse consequence of a NSP with a poor submission incurring a lower penalty if it were to overspend. 12. The AER should be undertaking more intensive audits of NSPs' capital requirements. 13. The CESS may not be necessary because there are already 8 lines of defence (the regulated rate of return, detailed capex assessments, ex-post reviews, the RIT-T and RIT-D tests, the guaranteed service level payment scheme, the Better Resets Handbook, the STPIS and annual performance reporting, and the DMIS). 14. The CESS focuses on ex-post management effort, rather than ex-ante management effort before a NSP submits its regulatory proposal. 15. The CESS encourages NSPs to conceal their true capex requirements, and provides an incentive for NSPs to overstate their capex requirements.
Endeavour Energy	✓	No preference expressed.	1. Adopts the ENA's submission. 2. Cautions against drawing conclusions given the CESS has only been operating for one round of regulatory control periods. 3. Premature to change the strength of incentives. A reduced CESS reward could bias towards opex savings. 4. There are considerable safeguards within the regulatory framework to mitigate against inefficient capex or deferrals being rewarded by the CESS. 5. A flexible approach to applying incentive scheme rewards and benefits must be mindful of the importance of providing regulatory certainty and a balanced incentive framework.
Energy Queeensland	✓	No preference expressed.	1. The CESS has only been operating for one round of regulatory control periods and changes are therefore unnecessary. 2. Concerns about over-forecasting of capex should be addressed by improving capex forecasting.
Energy Networks Australia (ENA)	✓	Bright Line Tiered Test	1. CESS is fit for purpose and has benefitted consumers. HoustonKemp estimates consumers have benefitted $13.4 billion in 2020 present value terms (across the EBSS, the CESS and the reliability component of the STPIS); equating to $1,466 for an electricity and gas customer, and $1,290 for an electricity only customer. 2. Supports retaining the CESS as is. Case to change CESS not made out. Further evidence is required. 3. A variable CESS rate will weaken incentives to deliver efficiencies and has the potential for perverse incentives and unintended consequences. 4. Supports AER addressing issues through its expanded regulatory toolkit. 5. CESS reform should be guided by (a) maintaining strong incentives to continually achieve efficiencies; (b) ensure incentive rewards are targeted at genuine efficiencies; (c) minimise regulatory burden and maintain simplicity; (d) predictability in application. 6. If the case to change the CESS is made out, supports the AER further considering the Bright Line Tiered Test.
Essential Energy	✓	No preference expressed.	1. Adopts the ENA's submission. 2. No evidence that NSPs are overstating their capex requirements. 3. Should address the issue of information asymmetry rather than reduce the incentive power of the CESS. 4. The AER should clarify the application of the CESS to deal with exogenous events, capex/opex definitions, treatment of cost pass-throughs, and when the CESS might not be applied.

Evoenergy	✓	No preference expressed.	1. Adopts the ENA's submission, 2. CESS is fit for purpose. The balance between the EBSS and the CESS sharing ratios should not be changed.
Jemena	✓	Bright Line Tiered Test	1. Adopts the ENA's submission. 2. A 10 per cent threshold does not adequately account for the size and scale of different DNSPs, particularly given the lumpy nature of many capex projects. AER should consider classifying networks into small, medium and large, and applying a different threshold accordingly (e.g. 25, 20 and 15 per cent).
Network of Illawarra Consumers of Energy (NICE)	X	Modified bright line test	1. The AER should adopt the description of Performance Based Regulation to describe the regulatory regime. 2. The CESS is not fit for purpose and could be retained under an alternative design. 3. The CESS should be asymmetric. 4. The AER should confirm how the return on capital of an underspend is to be treated. 5. The assumed sharing ratio for the CESS calculation should be based on the actual WACC applied to the EBSS model. 6. Supports a Bright Line Test that applies mechanistically different sharing ratios to different networks.
SA Power Networks (SAPN)	✓	Bright Line Tiered Test	1. Adopts the ENA's submission. 2. The CESS has only been applied for one regulatory control period. 3. If a problem exists, this should be dealt with by the AER's assessment processes. 4. The AER is already able to adjust CESS payments for deferrals. 5. Applying a bespoke or tiered CESS presents risks and may punish those who achieve efficiencies.
Red Energy	?	No preference expressed.	1. Over-forecasting must be addressed, otherwise the CESS should not apply.
Origin Energy	✓	No preference expressed.	1. Important that underspends reflect genuine efficiency gains. 2. Unclear whether the CESS is contributing to expenditure timing within a regulatory control period. 3. Onus should be on NSPs to explain underspends. 4. AER should consider ex-post review of larger projects. 5. Information asymmetry and difficulty in assessing expenditures means NSPs are able to game the CESS.
TasNetworks	✓	Bright Line Tiered Test	1. Adopts the ENA's submission. 2. Supports retaining the CESS as is. Case to change CESS not made out. Further evidence is required. 3. Supports further transparency. AER should focus on forecasting and the Better Resets Handbook. 4. How changes to the CESS relate to the capital expenditure incentive objective or the capital expenditure share scheme principles in the NER need to be clarified.

Transgrid	✓	Options not supported.	1. Adopts the ENA's submission. 2. Supports retaining the CESS as is. Case to change CESS not made out. 3. Supports further transparency. 4. AER should have regard to the specific circumstances of TNSPs. 5. AER should review interactions with the EBSS.