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Review of the AER's Proposed Output Weightings

Prepared for CitiPower, Powercor, United Energy and SA Power Networks

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Project Team

Richard Druce
George Anstey
Dr William Taylor
Soren Christian
Max Luke
Tommaso Marossi

NERA Economic Consulting
One International Towers Sydney
100 Barangaroo Ave
Sydney NSW 2000
+61 2 8864 6535
www.nera.com

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Introduction and Background

CitiPower, Powercor, United Energy and SA Power Networks have commissioned NERA Economic Consulting to conduct an expert review of the approach use by the Australian Energy Regulator (AER) to index Distribution Network Service Providers' (DNSPs') allowed operating expenditure (opex) to changes in outputs.

The AER sets allowances for DNSPs' opex using a "base-step-trend" approach, which includes a process of forecasting how DNSPs' efficient opex will change in the subsequent Regulatory Period as a result of changes in outputs.

In price control decisions prior to 2018, the AER linked DNSPs' output-based changes in allowances to the Cobb-Douglas (CD) Stochastic Frontier Analysis (SFA) econometric model used by the AER and its consultants Economic Insights (EI) to assess DNSPs' efficient "base year" opex. The AER used the coefficients on each of the three outputs – customer numbers, circuit length and ratcheted maximum demand – to define weights for the growth rates for each of those outputs.

However, the AER is proposing to change its approach to setting allowed opex following a critique by the Consumer Challenge Panel (CCP10) and a ruling by the Australian Competition Tribunal (the Tribunal). CCP10 argued that output growth factors from Economic Insight model had applied greater weight on customer growth than were applied in an equivalent exercise in New Zealand, while the Tribunal criticised AER's sole reliance on this "experimental model as the sole determinant of opex".[1]

In its 2018 draft decisions for DNSPs in ACT, New South Wales and Tasmania, the first since the CCP10 critique and Tribunal ruling, the AER drew on a wider range of benchmarking methods: Cobb-Douglas SFA, Cobb-Douglas Least Squares (LS), Translog (TL) LS and Multilateral Partial Factor Productivity (MPFP).

The outputs included in the new models are the same three as the AER used previously (customer numbers, circuit length, and ratcheted maximum demand), with the addition of energy throughput for the MPFP model. We present the proposed weights in Table 1 below.

Table 1: Output Weights by Model from 2018 EI Benchmarking Update

	CD SFA	CD LS	TL LS	MPFP
Customer Numbers (#)	70.80%	67.59%	51.52%	31.00%
Circuit Length (km)	16.81%	11.78%	13.86%	29.00%
Ratcheted Maximum Demand (MW)	12.39%	20.63%	34.62%	28.00%
Energy Throughput (GWh)				12.00%

Source: EI[2]

1 (1) Consumer Challenge Panel (subpanel 10) (16 May 2018), Response to Evoenergy regulatory proposal 2019-24 and AER issues paper p. 10. (2) Australian Energy Regulator v Australian Competition Tribunal No 2 (2017), FCAFC 79, para.257.

2 Economic Insights (9 November 2018), Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Annual Benchmarking Report, Tables 3.3-3.5, scaled to sum to 1.0.

Approach to Appraising the AER's Updated Approach

We appraise the AER's updated approach against two criteria informed by the AER's statutory obligations and responsibilities set out in National Electricity Law (NEL) and the National Electricity Rules (NER):

The National Electricity Objective (NEO) (within the NEL) is "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system."[3] We therefore consider whether the AER's proposed approach in the long-term interest of consumers of electricity.

The opex criteria of the NER, which in some sense implement aspects of the Revenue and Pricing Principles (RPP) in the NEL,[4] stipulate that an efficient operator should have a reasonable opportunity to recover its costs, and that any determination made by the AER should reasonably reflect the operating costs that a prudent operator would incur to provide distribution services. We therefore consider whether the AER's proposed approach is likely to remunerate the efficient costs of providing distribution services.

Appraisal of MPFP Model

We find that the MPFP model weights are unlikely to reflect the drivers of cost of an efficient operator, and that the model is therefore inconsistent with the NER.

The process for deriving weights from the MPFP modelling has been opaque: The output weights that EI uses are treated as an input into the efficiency benchmarking process. There is little documentation on how the weights themselves have been derived. We have gleaned some components of the AER's methodology from another similar study done by EI in New Zealand as well as through reading EI's modelling code, but this may not satisfy standards of transparency set out in the NER.

The drivers included in the MPFP modelling were chosen based on tariff structure, not by assessing their effect on DNSPs' costs: EI chose drivers to include in the MPFP model on the basis that they were drivers of revenue and hence reflected the design of regulated tariffs. While the AER has an objective to ensure cost reflectivity of tariffs, tariffs may not be designed in such a way that they are cost reflective; the ongoing process of tariff reform in Australia and elsewhere to address structural changes in the electricity sector suggests that they are not.

The weights in the MPFP model are artificially constrained to be positive, masking possible misspecification of the model: After an attempt to estimate weights resulted in negative coefficients, EI adopted an approach of using squared coefficients, which guaranteed that EI

3 National Electricity (South Australia), Act 1996, Schedule – National Electricity Law, Section 7.

4 E.g. 7A, 2 (a) of the NEL states:
"A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
(a) providing direct control network services; and
(b) complying with a regulatory obligation or requirement or making a regulatory payment."

would end up with a positive relationship between costs and outputs in the MPFP model, even where no relationship exists.

The MPFP weights are estimated with very little data, suggesting the weights are estimated imprecisely: EI estimates a separate regression for each company, so each has only 12 data points. This is unlikely to be enough data to calibrate the relationship between costs and drivers accurately.

Appraisal of the Use of Energy Throughput as a Driver

Changes in energy throughput do not drive changes in DNSPs' efficient operating costs, as noted by the AER in its 2018 Annual Benchmarking Report: "energy throughput is not considered a significant driver of costs (distribution networks are typically engineered to manage maximum demand rather than throughput…".[5] Indeed, CCP10 made a similar observation when critiquing the weight the AER had placed on customer numbers.[6] Thus, linking allowances to this driver does not satisfy the operating expenditure criteria in the NER.

Historically, growth in energy throughput may have approximated growth in peak demand (a variable already separately included in the AER/EI models). However, recent developments in the sector such as the deployment of customer-sited solar photovoltaics (PV) and other technologies have altered traditional customer load profiles. Due to the growing use of load-altering technologies, network-wide changes in energy throughput no longer accurately predict proportionate changes in peak demand or distributors' costs.

In fact, the link between energy throughput and costs could reverse, if the growth in embedded generation both reduces energy throughput while also imposing additional distribution costs that are not captured by customer numbers and ratcheted peak load. For example, DNSPs may need to expand network capacity (and incur any associated operating costs) to accommodate localised peaks in the export of embedded generation to other parts of the electricity distribution or transmission systems.

While distribution allowances and tariff structures in Australia and worldwide (particularly in the UK and the US) have historically been linked to measures of energy throughput, recent reforms and trends in regulatory regimes have delinked revenues from changes in energy throughput, in recognition of the mismatch between opex and energy throughput in reality.

Appraisal of the Translog Model

We find that the translog model weights are unlikely to reflect the drivers of cost of an efficient operator, and that the model is therefore inconsistent with the NER.

The AER has not considered whether the coefficients in its translog model imply intuitive engineering or economic relationships.

The AER's translog model differs from the Cobb-Douglas model in that it allows the elasticity of opex to each driver to depend on the levels of all drivers. The model estimates

5 AER (November 2018), Annual Benchmarking Report – Electricity distribution network service providers, p.51.

6 Consumer Challenge Panel (subpanel 10) (16 May 2018), Response to Evoenergy regulatory proposal 2019-24 and AER issues paper p. 10.

these tendencies through a set of "second-order" coefficients. Neither the AER nor EI appear to have considered whether the second-order coefficients are intuitive or reasonable. We find that they are not:

1. According to the model, the opex of a DNSP with more kilometres of circuit will be *less* sensitive to growth in peak demand than an otherwise identical DNSP with fewer kilometres of circuit. This does not match the intuitive relationship.
2. The model suggests that every company could *reduce* opex by increasing customer numbers, all else held equal. This violates the "monotonicity" condition that EI sought to ensure in designing this model.

For similar reasons, the UK Competition & Markets Authority rejected a translog model proposed by the UK water regulator (Ofwat) to set cost allowances for water companies in England and Wales.

By choosing weights only based on "first-order" coefficients, the AER's cost indexation approach is not consistent with its econometric results.

By ignoring the second-order coefficients, the AER proposes to base allowances on relationships which are not implied by the translog model. However, if it were to include the second-order coefficients, the results are not credible. For instance, the model implies a 1 per cent increase in customer numbers leads to a 2.5-3 per cent *reduction* in efficient opex.

Conclusions and Recommendations

We find that the MPFP and translog models as currently designed, as well as the use of energy throughput as a driver, do not reflect the costs that an efficient operator would incur in providing distribution services. Therefore, these models and this driver do not satisfy the opex criteria in the NER.

Moreover, by failing to remunerate companies for their efficient expenditure, the AER would limit incentives to carry out efficient investment in the system, contrary to the long-term interests of electricity consumers. Therefore, the AER's approach does not achieve the NEO.

We therefore recommend that the AER bases output weights on the two Cobb-Douglas models – SFA and LS – which do not appear to materially mis-estimate the drivers of DNSPs' costs. Basing output weights on a simple average of the coefficients in these two models may be a proportionate solution to the problems we have identified, and appears to satisfy the operating expenditure criteria and, by extension, the NEO.

Such an approach also addresses the Tribunal's criticism that the AER has relied too heavily on a single model, as we recommend that it rely on *two* models.

The two models imply similar weights on customer numbers, suggesting that our recommended approach does not address the concerns raised by CCP10. However:

- CCP10 did not provide compelling evidence that the SFA model over-estimated the importance of customer numbers. Instead, it cited the econometric findings of a regulator in a different country (New Zealand) whose DNSPs operate under different conditions than those in Australia, as well as its own internal (unsupported) position that operating costs are driven mainly by peak demand.

- Of the four models included in the AER’s proposal, the fact that two more robust models (the Cobb-Douglas models) imply similar weights on customer numbers appears to be stronger evidence than presented in CCP10’s critique.
- The weight on customer numbers is lower in the 2018 iteration of the SFA model (and the CD LS model) than the 2017 SFA model criticised by CCP10. Therefore, CCP10’s concerns have been addressed at least partially by the passage of time and addition of data to the EI models.

1. Introduction

1.1. Our Assignment

CitiPower, Powercor, United Energy and SA Power Networks have commissioned NERA Economic Consulting to conduct an expert review of the approach used by the Australian Energy Regulator (AER) to index Distribution Network Service Providers' (DNSPs') allowed operating expenditure (opex) to changes in outputs.

The AER sets allowances for DNSPs' opex using a "base-step-trend" approach. Part of this process involves forecasting how DNSPs' efficient opex will change in the subsequent Regulatory Period through an allowed "rate of change" component of the price control. The allowed rate of change accounts for the AER's forecast change in DNSPs' input prices (labour, materials, etc), the AER's ongoing productivity target, and the effect on opex from changes in outputs.

1.2. Background on the AER's Output Indexation Approach

At the last resets for CitiPower, Powercor, United Energy and SA Power Networks, the AER applied an index of outputs comprising customer numbers, circuit line length and ratcheted maximum demand in its allowed rate of change in opex. It combined these factors using weights derived from the coefficients in opex benchmarking models, estimated by Economic Insights (EI) for use in that reset. The model implemented a Cobb-Douglas cost function, estimated using a Stochastic Frontier Analysis (SFA) estimation technique.[7]

However, since then, EI and the AER have changed their approach to setting allowed opex following a critique by the Consumer Challenge Panel (CCP10) and a ruling by the Australian Competition Tribunal (the Tribunal). CCP10 stated that output growth factors from the Economic Insight model had applied greater weight on customer growth than were applied in an equivalent exercise in New Zealand. The NZ Commerce Commission instead placed greater weight on maximum demand, which CCP10 considers to be the primary driver of network costs.[8] The Tribunal's ruling also criticised various aspects of the Cobb-Douglas SFA modelling[9] and the AER's sole reliance on this "experimental model as the sole determinant of opex".[10]

In response to the Tribunal's ruling, the AER has changed its benchmarking approach in its most recent resets for DNSPs in ACT, Tasmania and New South Wales. Amongst other things, the AER drew on a wider range of benchmarking methods: Multilateral Partial Factor Productivity (MPFP), Cobb-Douglas SFA, Cobb-Douglas Least Squares (LS), and Translog

7 (1) AER (May 2016), CitiPower distribution determination 2016-2020, final decision, attachment 7: operating expenditure, p.89. (2) AER (October 2015), CitiPower distribution determination 2016-2020, preliminary decision, attachment 7: operating expenditure, pp.64-65.

8 Consumer Challenge Panel (subpanel 10) (16 May 2018), Response to Evoenergy regulatory proposal 2019-24 and AER issues paper, p.10.

9 Australian Energy Regulator v Australian Competition Tribunal No 2 (2017), FCAFC 79, paras.221, 225 and 234.

10 (1) Consumer Challenge Panel (subpanel 10) (16 May 2018), Response to Evoenergy regulatory proposal 2019-24 and AER issues paper p. 10. (2) Australian Energy Regulator v Australian Competition Tribunal No 2 (2017), FCAFC 79, para.257.

LS.[11] It used estimated coefficients from these models to weight the different output metrics included in the allowed rate of change. The outputs included in the new models are the same three as the AER used previously (customer numbers, circuit length, and ratcheted maximum demand), with the addition of energy delivered to the MPFP model.

1.3. Structure of this Report

Against this background, the remainder of this report is structured as follows:

- Chapter 2 provides further background on the rules governing the approach the AER uses to set allowed opex, its previous approach to output indexation, and the changes it has made to this approach in response to criticisms from CCP10 and the Tribunal's ruling.
- Chapter 3 provides our review of the AER's new approach to output indexation, used in its most recent resets.
- Chapter 4 sets out our recommendations for the AER's upcoming resets.

11 AER (September 2018), Evoenergy distribution determination 2019-2024, attachment 6: operating expenditure, p. 29.

2. Background

Every five years, the AER reviews capital expenditure (capex) and operational expenditure (opex) forecasts submitted by the DNSPs. Following a review, the AER defines the level of revenues a DNSP is allowed to recover over the subsequent five years.

These "resets" of the DNSPs' price controls are performed on a rolling basis by state: the next reset for DNSPs in ACT, New South Wales, Northern Territory and Tasmania will take effect in 2019; the next reset for DNSPs in Queensland and South Australia will take effect in 2020; and the next reset for DNSPs in Victoria will take effect in 2021.[12] The AER does not regulate networks in Western Australia.

In this chapter, we provide background on the regulatory arrangements the AER applies to the DNSPs, focussing on the opex components of the revenue allowance, and particularly the "rate of change" component of opex allowances:

- Section 2.1 summarises the AER's objectives with reference to the National Electricity Law (NEL), the National Electricity Rules (NER) and the National Electricity Objective (NEO);
- Section 2.2 describes the AER's "base-step-trend" approach to calculating DNSPs' allowed opex with more detail in Section 2.3 on the AER's approach to measuring and accounting for changes in outputs, a component of the rate of change in opex allowance;
- Section 2.4 discusses recent changes in the AER's approach to accounting for changes in outputs, in particular the 2016 Australian Competition Tribunal case which quashed the AER's determinations for DNSPs in New South Wales, and the Consumer Challenge Panel 2018 response to the recent Evoenergy regulatory proposal; and
- Section 2.5 discusses the AER's updated approach to measuring output growth, as proposed in recent draft decisions in ACT and New South Wales.

2.1. The AER's Objectives and Statutory Requirements

The NEL and the NER guide the AER's regulation of electricity networks. These two pieces of legislation lay out the functions, responsibilities and powers of the AER.

2.1.1. The National Electricity Law

The goal of the NEL, set out by the NEO, is:

> "… to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and

[12] AER (July 2018), AER 7 year regulatory determination calendar excluding WA, URL: https://www.aer.gov.au/system/files/D17-17248%20AER%207%20year%20regulatory%20determination%20calendar%20excluding%20WA%20%28updated%20July%202018%29.XLSX.pdf

(b) the reliability, safety and security of the national electricity system."[13]

The Revenue and Pricing Principles (RPP) of the NEL further stipulate that a network service provider "should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in (a) providing direct control network services; and (b) complying with a regulatory obligation or requirement or making a regulatory payment".[14]

According to the NEL, when performing a regulatory function or power, the "AER must […] perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the national electricity objective".[15] Furthermore, the AER "must take into account the revenue and pricing principles when exercising a discretion in making those parts of a distribution determination […] relating to direct control network services".[16]

2.1.2. The National Electricity Rules

While the NEL sets out the AER's statutory requirements, the NER provides a more detailed implementation framework that the AER is required to follow in meeting those requirements.

The NER requires that a DNSP's opex proposal must achieve the operating expenditure objectives, which are to meet or manage expected demand; comply with all regulatory obligations or requirements; maintain quality, reliability and security of supply; and maintain the safety of the distribution network.[17]

The NER also defines the criteria against which the AER assesses whether a DNSP's proposal achieves the operating expenditure objectives:[18]

> "The *AER* must accept the forecast of required operating expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* if the *AER* is satisfied that the total of the forecasting operating expenditure for the *regulatory control period* reasonably reflects each of the following (the *operating expenditure criteria*):
>
> (1) The efficient costs of achieving the *operating expenditure objectives*: and
>
> (2) The costs that a prudent operator would require to achieve the *operating expenditure objectives*; and
>
> (3) A realistic expectation of the demand forecast and cost inputs required to achieve the *operating expenditure objectives*."

[13] National Electricity (South Australia), Act 1996, Schedule – National Electricity Law, Section 7.

[14] National Electricity (South Australia) Act 1996, Schedule – National Electricity Law, Section 7A(2).

[15] National Electricity (South Australia), Act 1996, Schedule – National Electricity Law, Section 16(1).

[16] National Electricity (South Australia), Act 1996, Schedule – National Electricity Law, Section 16(2).

[17] National Electricity Rules, v114, clause 6.5.6(a).

[18] National Electricity Rules, v114, clause 6.5.6(c). Italics in original.

If the AER is not satisfied that the DNSP's proposal satisfies the operating expenditure criteria, it must provide its own estimate of required opex that does satisfy the criteria.[19]

Additionally, per clause 6.12.2, when replacing a DNSP proposal with its own estimate, the AER must "set out the basis and rationale of the determination, including: (1) details of the qualitative and quantitative methods applied in any calculations and formulae made or used by the AER".[20]

2.2. Description of the Base-Step-Trend Method for Setting the Opex Allowance

At each reset, the AER sets the level of efficient opex that each DNSP is allowed to recover for the subsequent five-year regulatory period.

To form a judgment as to the efficient level of opex for a DNSP, the AER first reviews the DNSP's own forecast of total opex. If it is not satisfied that the DNSP's forecast reasonably reflects the opex criteria, it must substitute the DNSP's forecast with its own that does reflect the opex criteria.[21]

To build its own forecast, the AER adopts a base-step-trend approach that defines base opex for a recent year, and then applies a yearly rate of change and step changes to set the overall level of allowed opex.[22]

2.2.1. Base opex

To assess base opex, the AER evaluates the DNSP's historical opex in a recent year, relying on its Annual Benchmarking Report which compares opex efficiency across all 13 DNSPs in the NEM.[23]

If the benchmarking results suggest that a company's opex is efficient, AER will use the DNSP's historical opex in the penultimate year of the previous control period as its base opex.[24] Otherwise, the AER adjusts the DNSP's historical opex to bring it to the efficient level, based on one or more of the econometric benchmarking models.

2.2.2. Rate of change

The AER applies a rate of change to base opex to forecast yearly changes in opex in the next regulatory period. The rate of change reflects expected growth in efficient opex due to changes in output drivers, input prices and productivity.

19 National Electricity Rules, v114, clause 6.12.1(4).

20 National Electricity Rules, v114, clause 6.12.2.

21 AER (November 2018), Ausgrid Distribution determination 2019-24 – Draft Decision – Attachment 6 – Operating Expenditure, p.10-11.

22 (1) AER (November 2013), Better Regulation – Expenditure Forecast Assessment Guideline for Electricity Distribution, p.22.

23 See, e.g., AER (November 2018), Annual Benchmarking Report – Electricity distribution network service providers

24 See for example: AER (May 2016), CitiPower distribution determination 2016 to 2020, Final Decision – Attachment 7 – Operating Expenditure, p. 21.

The output growth component of the rate of change reflects the forecast annual increase in selected output indices, whilst the input price component forecasts the annual increase in DNSPs' input costs using a combination of labour and non-labour input price changes.

The AER estimates expected productivity growth with reference to the industry's recent rate of productivity improvement, but in the past has applied no productivity growth in its resets.[25] The AER is currently consulting on its approach to calculating the productivity adjustment, and in its recent draft decision for the New South Wales companies, it has suggested that it could incorporate a non-zero productivity growth rate in its final decisions.[26]

2.2.3. Step changes

The AER accounts for the possibility of further modifications to opex forecasts whenever there are opex components that are not compensated for in the base opex or in the rate of change. In general, the AER includes step changes only in "exceptional" circumstances.[27]

2.3. The AER's Approach to Output Growth Indexation

As described above, the AER applies a rate of change to base opex to capture changes to efficient opex driven by changes in input prices, productivity and output drivers.

The AER's forecast changes in efficient opex driven by output growth derives from the benchmarking modelling it performs to assess efficient base opex. In its past decisions up to the 2015-20 South Australia reset, the AER took the output-related coefficients (i.e. on customer numbers, circuit length and ratcheted maximum demand) from its SFA modelling, and scaled to ensure that they sum to one.[28] This approach assumes the AER's statistically-estimated relationships accurately capture the relative importance of each output driver in determining changes in efficient opex. The AER's approach also assumes that, all else equal, a 1 per cent growth in all three output variables would lead to an increase in efficient opex by exactly 1 per cent.

2.4. Recent Critiques of AER Benchmarking Techniques

2.4.1. ActewAGL and Networks NSW's appeal to the Australian Competition Tribunal

In May 2015, the ActewAGL and New South Wales DNSPs (with the latter referred to collectively in the preceding as "Networks NSW"), appealed their 2014-19 distribution determinations to the Australian Competition Tribunal for a merits review on several grounds, including opex allowances.[29] Networks NSW argued that the AER's estimates of

[25] E.g. the 2014-19 control period for NSW DNSPs and the 2015-20 control period for Victorian NSPs.

[26] (1) AER (November 2018), Forecasting productivity growth for electricity distributors – Draft decision paper; (2) AER (November 2018), Ausgrid Distribution determination 2019-24 – Draft Decision – Attachment 6: Operating Expenditure, p.40.

[27] AER (September 2018), Evoenergy Distribution Determination 2019-2024 – Draft Decision – Attachment 6: Operating Expenditure, p.13-15.

[28] AER (October 2015), SA Power Networks determination 2015-16 to 2019-20 – Final Decision – Attachment 7: Operating Expenditure, p.36.

[29] Australian Competition Tribunal (26 February 2016), Applications by Public Interest Advocacy Centre Ltd and Ausgrid, paras. 115-497.

efficient opex were too low because the AER "ignored [opex actually incurred] and instead relied on an unsound and untested econometric model […] to estimate opex", an SFA model estimated by Economic Insights.[30] Furthermore, Networks NSW questioned whether, "having regard to the data limitations and other matters, any of the models are fit to be given 100 percent weight in assessing an appropriate level of opex".[31] Similarily, ActewAGL argued "the AER's benchmarking has such serious technical deficiencies that it has no value as a means of assessing ActewAGL's efficient costs."[32]

In February 2016, the Tribunal found inadequacies in both the specification of the EI model (such as the inclusion of data from overseas networks) and the AER's "use of the EI model as the sole or principal determinative of opex".[33] As a result, the Tribunal concluded that the AER "failed to discharge its obligations under rr 6.5.6 and 6.12.1(4)" of the NER, which require the AER to accept a proposal that satisfies the operating expenditure criteria or replace it with one that does.[34]

The Tribunal therefore ruled in favour of ActewAGL and Networks NSW in relation to their appeal against the AER's opex determination. It set aside the AER's determination and remitted to the AER to re-make the decision based on "a broader range of modelling, and benchmarking against Australian businesses, and including a 'bottom up' review" of opex.[35]

Following the Tribunal judgment, the AER applied to the Federal Court of Australia for a judicial review challenge of the Tribunal judgment. In its decision of May 2017, the Court found that "the AER has not established any of the grounds of judicial review in relation to forecast opex".[36]

2.4.2. The CCP10 critique

In 2013, the AER established the Consumer Challenge Panel (CCP), with the objective of advising the AER "on whether the network businesses' proposals are in the long term interest of consumers" and to "provide input and challenge the AER on key consumer issues during a network determination".[37]

In response to Evoenergy's 2019-24 proposal, released on 31 January 2018, the CCP sub-panel 10 (CCP10) submitted a response document on the level of revenues requested by

30 Australian Competition Tribunal (26 February 2016), Applications by Public Interest Advocacy Centre Ltd and Ausgrid, para. 126.

31 Australian Competition Tribunal (26 February 2016), Applications by Public Interest Advocacy Centre Ltd and Ausgrid, para. 127.

32 Australian Competition Tribunal (26 February 2016), Applications by Public Interest Advocacy Centre Ltd and Ausgrid, para. 131.

33 Australian Competition Tribunal (26 February 2016), Applications by Public Interest Advocacy Centre Ltd and Ausgrid, para. 467.

34 Australian Competition Tribunal (26 February 2016), Applications by Public Interest Advocacy Centre Ltd and Ausgrid, para. 495.

35 Australian Competition Tribunal (26 February 2016), Applications by Public Interest Advocacy Centre Ltd and Ausgrid, para. 1227.

36 Federal Court of Australia (24 May 2017), Australian Energy Regulator v Australian Competition Tribunal (No 2) [2017] FCAFC 79, para. 386.

37 AER, Consumer Challenge Panel, accessed 15 November 2018. URL: https://www.aer.gov.au/about-us/consumer-challenge-panel

Evoenergy.[38] CCP10 criticised Evoenergy's proposal on the grounds that the trend component was based on the AER's SFA model, which, it argued, places "significantly larger" weight on the relationship between costs and customer numbers "than comparable estimates by [New Zealand] Commerce Commission for NZ DNSPs". Instead, CCP10 posited that maximum demand is "the primary driver of network costs", though it did not provide any support for this position.[39]

2.5. Output Growth Indices Proposed in the AER's 2018 Draft Decisions

2.5.1. The AER has proposed to rely on a wider range of models to set output weights

In September and November 2018, the AER released its first draft decisions (excluding the remittals of the ACT and NSW determination)[40] since the Tribunal judgment and the CCP10 critique, covering DNSPs in ACT, New South Wales, Tasmania and the Northern Territory.

In all of these draft decisions, the AER sought to address the concerns of both the Tribunal (that too much weight was placed on a single model output) and CCP10 (that too much weight was placed on customer numbers as an output driver).[41]

Instead of relying exclusively on the coefficients from the SFA model, the AER now proposes to derive weights from four models that EI has included in its annual benchmarking exercises: the SFA model, plus three others which have previously been used as a cross-check. The other three models show a lower weight on customer numbers, addressing CCP10's criticism, while the reliance on four models rather than one addresses the Tribunal's concern.

We describe these approaches below, and how the AER proposes to derive output weights from them.

2.5.2. The Cobb-Douglas SFA model

Prior to the 2018 draft decisions, the AER based its base opex efficiency assessment solely on EI's Cobb-Douglas SFA model. SFA models differ from an ordinary least squares regression models, in that they estimate a company's inefficiency by separating the unexplained "residual" component of the regression into a random error term and an inefficiency term.

In order to separate the "residual" component, more data points are required than could be collected from DNSPs in Australia. EI therefore includes data from DNSPs in New Zealand and Ontario to help calibrate the model.

38 (1) Evoenergy (31 January 2018), Eveoenergy regulatory proposal for the ACT electricity distribution network; (2) Consumer Challenge Panel (subpanel 10) (16 May 2018), Response to Evoenergy regulatory proposal 2019-24 and AER issues paper.

39 Consumer Challenge Panel (subpanel 10) (16 May 2018), Response to Evoenergy regulatory proposal 2019-24 and AER issues paper, p.10.

40 Final decisions on the remittals were made in May 2018.

41 See for example: AER (November 2018), Ausgrid Distribution determination 2019-24 – Draft Decision – Attachment 6: Operating Expenditure, p.38-39.

The model that the AER/EI estimates is as follows:

$$\ln(opex_{it}) = \beta_0 + \beta_1 * \ln(CN_{it}) + \beta_2 * \ln(CL_{it}) + \beta_3 * \ln(RMD_{it}) + \beta_4 * \ln(UGC_{it}) + \gamma * year + \delta_1 * Ontario + \delta_2 * NZ + u_i + v_{it}$$

where *CN* is customer numbers, *CL* is circuit length, *RMD* is Ratcheted Maximum Demand (ratcheted so that it is non-decreasing over time and reflects the highest demand ever observed on the network as of a particular date), *UGC* is the share of underground cables, u_i is time-invariant inefficiency and v_{it} is a random error term. The notation *ln(.)* means that the model uses a natural logarithm of the variable rather than the variable itself, which is a feature of the Cobb Douglas cost function.

With this model, as with the other econometric models, the AER uses the output-related coefficients to define output weights from this model, scaled such that they sum to one. For instance, the AER calculates the weight on customer numbers as follows, and applies similar calculations for the weights on circuit length and ratcheted maximum demand:

$$Weight_{CN} = \frac{\beta_1}{\beta_1 + \beta_2 + \beta_3}$$

2.5.3. Cobb-Douglas least squares

Additionally, the AER now includes the least squares equivalent of the Cobb Douglas model shown above, which differs from the SFA model in two important respects:

1. As noted above, least squares models do not seek to decompose the residual component of the econometric model into a random error and inefficiency component. While this estimation approach is therefore less data intensive than the SFA model, EI continues to include data from New Zealand and Ontario in this model.
2. EI includes a DNSP-specific dummy variable for each of the 13 Australian DNSPs,[42] such that the coefficient on each dummy represent an estimate of the degree of each DNSP's inefficiency.

The econometric model is therefore defined as follows:

$$\ln(opex_{it}) = \beta_0 + \beta_1 * \ln(CN_{it}) + \beta_2 * \ln(CL_{it}) + \beta_3 * \ln(RMD_{it}) + \beta_4 * \ln(UGC_{it}) + \gamma * year + \delta_1 * Ont + \delta_2 * NZ + \delta_3 * AGD + \cdots + \delta_{14} * UED + v_{it}$$

The AER then derives output weights from the three output-related coefficients in the same way as for the SFA model, again scaling so that they sum to one.

2.5.4. Translog least squares

The third econometric model uses a "translog" cost function instead of the Cobb-Douglas approach, and uses the least squares estimation approach. A translog model differs from a Cobb-Douglas model in that it includes squared and cross-product terms for each of the output drivers:

42 Omitting one as required to avoid a dummy variable trap of multicollinearity.

$$\ln(opex_{it}) = \beta_0 + \beta_1 \ln(CN_{it}) + \beta_2 \ln(CL_{it}) + \beta_3 \ln(RMD_{it}) + \beta_{11} \frac{\ln(CN_{it})^2}{2} + \beta_{22} \frac{\ln(CL_{it})^2}{2} + \beta_{33} \frac{\ln(RMD_{it})^2}{2} + \beta_{12} \ln(CN_{it}) \ln(CL_{it}) + \beta_{13} \ln(CN_{it}) \ln(RMD_{it}) + \beta_{23} \ln(CL_{it}) \ln(RMD_{it}) + \gamma year + \delta_1 Ontario + \delta_2 NZ + \delta_3 AGD + \cdots + \delta_{14} UED + v_{it}$$

While the Cobb Douglas model assumes the elasticity of costs to changes in outputs are defined by single parameters (e.g. β_1 for customer numbers), a translog model assumes that the elasticity of opex to output levels depends on the level of all outputs included in the model.[43] The theoretical benefit of this approach is that it allows for a more flexible specification of relationships between drivers than the Cobb Douglas model, but it results is a more complex cost function with more parameters to be estimates. For instance, while the elasticity of opex with respect to changes in customer numbers in the Cobb Douglas model is simply given by the β_1 coefficient, the same elasticity in the translog model is given by:

$$\beta_1 + \beta_{11} \ln(CN_{it}) + \beta_{12} \ln(CL_{it}) + \beta_{13} \ln(RMD_{it})$$

In its recent draft decision, the AER proposes to derive output weights from the three "first order" output-related coefficients in the translog model using the same approach as in the Cobb Douglas models, again scaling so that they sum to one.

2.5.5. Multilateral Partial Factor Productivity

The final component of the AER's proposed output growth model derives from its MPFP analysis, which EI has included in its benchmarking reports as a cross-check since 2013.[44]

The MPFP approach to deriving output weights differs from the other three, in that weights are not calculated as a *result* of the benchmarking exercise, but are rather used as an *input* to the benchmarking process.

While EI has updated the MPFP efficiency analysis in each year to reflect updated cost and driver data, it has continued to use the same output weights that it derived in econometric analysis in 2014 through to the 2018 draft decisions, without updating that analysis to reflect potential changes to the estimated relationships between output drivers and opex.[45] However, in the 2018 EI benchmarking update, which has not yet been reflected in any decisions, EI has re-estimated these weights using data from 2006 to 2017.[46]

To estimate these weights, EI carried out the following steps:

[43] "Elasticity" refers to the percentage change in one variable that happens as a result of a one per cent increase in another. For example, if the Opex-to-Customer-Numbers elasticity was 0.5, this would mean that a 1 per cent increase in customers would increase opex by 0.5 per cent. In the case of a Cobb-Douglas model converted into a logarithmic form (as is this case in the two Cobb-Douglas models estimated by the AER), the elasticity is equal to the coefficient next to that driver (e.g. β_1).

[44] Economic Insights (25 June 2013), Economic Benchmarking of Electricity Network Service Providers.

[45] Economic Insights (25 June 2013), Economic Benchmarking of Electricity Network Service Providers, p. 23.

[46] Economic Insights (9 November 2018), Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Annual Benchmarking Report, p.109

- EI identified four individual cost inputs: opex, units of overhead lines (MVA-km), underground cables (MVA-km), and transformers (MVA);[47]
- EI selected four output variables which it deemed to be drivers of each of the cost inputs: Customer Numbers, Circuit Length, Ratcheted Maximum Demand, and Energy Throughput;[48]
- EI collected input cost and output data from the 13 Australian DNSPs between 2006 and 2013 to estimate the relationship between cost components and outputs, separately for each DNSP and each input cost item.
- EI first attempted to estimate the relationship between cost components and inputs using a translog function, but found negative coefficients on some of the relationships.[49] In order to prevent any counter-intuitive relationships between drivers and costs (i.e. negative coefficients on output drivers), EI estimated *squared* coefficients, which by definition must not be negative. In other words, the AER's approach guaranteed that it would find a positive contribution of each output to costs, even where no such relationship exists.
- Using the estimated coefficients (which varied across the DNSPs and the input cost items), EI calculated the share of DNSPs' total modelled opex which was driven by each output driver.

2.5.6. Weighting indices into a single output index

Table 2.1 sets out the output weights from each model, according to EI's 2018 benchmarking update. The weights differ from those in the 2018 draft decisions from EI's 2017 benchmarking update.

Table 2.1: Output Weights by Model from 2018 EI Benchmarking Update

	CD SFA	CD LS	TL LS	MPFP
Customer Numbers (#)	70.80%	67.59%	51.52%	31.00%
Circuit Length (km)	16.81%	11.78%	13.86%	29.00%
Ratcheted Maximum Demand (MW)	12.39%	20.63%	34.62%	28.00%
Energy Throughput (GWh)				12.00%

Source: EI[50]

Using the weights of each of the above models, the AER then combines with the forecast growth in each output to estimate a combined output growth rate implied by each of the four models. For example, if the AER forecasts a 3 per cent growth in Customer Numbers, a 2 per cent growth in Circuit Length and a 1 per cent growth in Ratcheted Maximum Demand in a particular year, the combined output growth rate for the CD SFA model would be 2.58 per

47 As derived from LCSTFNNLDOT.txt and DNSPData.txt, provided with EI's 2018 benchmarking files.

48 Economic Insights (17 November 2014), Economic benchmarking assessment of operating expenditures for NSW and ACT DNSPs, p.11.

49 Economic Insights (17 November 2014), Economic benchmarking assessment of operating expenditures for NSW and ACT DNSPs, p.12.

50 Economic Insights (9 November 2018), Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Annual Benchmarking Report, Tables 3.3-3.5, scaled to sum to 1.0.

cent (70.8% x 3% + 16.8% x 2% + 12.4% x 1%), while the output growth rate for the CD LSE model would be 2.47 per cent.

The AER then takes a simple average of these four model-specific growth rates to derive a single output growth rate, which when combined with its assumptions regarding the input price inflation and productivity improvement, defines the "rate of change" element of the allowance.

3. Appraisal of Proposed Approach

In this chapter, we review the AER's proposed approach to output indexation as described in Section 2 above. We appraise the approach against two criteria informed by the AER's statutory obligations and responsibilities set out in NEL and the NER.

The NEO (within the NEL) is "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system."[51] We therefore consider whether the AER's proposed approach in the long-term interest of consumers of electricity.

Both the RPP and the opex criteria of the NER stipulate that an efficient operator should have a reasonable opportunity to recover its costs. In particular, Rule 6.12.1 of the NER requires that any determination made by the AER should reasonably reflect the operating costs that a prudent operator would incur to provide the required distribution services. We therefore consider whether the AER's proposed approach is likely to remunerate the efficient costs of providing distribution services.

In appraising the AER's approach against these criteria, we have identified three problems with the AER's draft decision:

- In Section 3.1, we identify problems with EI's MPFP model that make it unsuitable for use in setting output weights as part of AER's output indexation. We find that the weights are unlikely to reflect the underlying drivers of opex, so this approach does not ensure AER remunerates DNSPs' efficient costs.
- In Section 3.2, we explain that energy throughput (one of the AER's four proposed output drivers) is not an appropriate measure of DNSPs' efficient operating costs, and its inclusion in the rate of change calculation represents a material departure from regulatory reforms being implemented internationally that seek to delink regulated revenues from the volume of energy throughput.
- In Section 3.3, we show that the AER has calculated the output weights from the translog model in a way that does not reflect the elasticity of costs to changes in output drivers. When calculated correctly, the output weights implied by the translog model are implausible.

3.1. Multilateral Partial Factor Productivity Model

3.1.1. The process for deriving weights from the MPFP modelling has been opaque

EI's MPFP process is used primarily as a benchmarking methodology, using the output weights as an input into the efficiency benchmarking that the AER then uses to inform its assessment of efficient base opex. While EI and the AER have set out the process through which they used the MPFP modelling to benchmark DNSPs' efficiency, they have published little detail on the approach they used to estimate the weights. An appendix to the EI annual benchmarking report gives a half-page description of the approach, but does not report the

[51] National Electricity (South Australia), Act 1996, Schedule – National Electricity Law, Section 7.

input variables used or show any statistical results that could be used to appraise the reliability of the weights.[52]

We have therefore reviewed other sources to identify the origin of EI's assumed output weights in the MPFP analysis. In particular, we reviewed some of the statistical output in the .txt files which contain the code to run regressions in Shazam, contained in the "LCSTFNNLDOT.txt" file.[53] We have not seen any written materials in which EI or the AER describes their methods or makes their own assessment of the reliability of the output weights as a means of keeping allowances in line with efficient opex in the rate of change calculation.

In our view, it is therefore unlikely that the AER's approach to calculating MPFP weights is consistent with Clause 6.12.2, which requires it to set out details of its quantitative methods.

3.1.2. The drivers included in the MPFP modelling were chosen based on tariff structure, not their effect on DNSPs' costs

EI assigns output weights to the four outputs that it includes into the non-linear models it uses to estimate the relationships between output variables and input cost drivers (e.g. opex): customer numbers, circuit length, ratcheted maximum demand and energy throughput.

Rather than base this selection of output drivers on an informed assessment of which factors influence DNSPs' efficient opex, EI selected a set of output drivers based largely on the criterion that they are measured in customer bills.[54]

In the case of energy throughput, EI decided to include it as a measured output not because it is a driver of opex (as we demonstrate is not the case in Section 3.2), but because "the majority of DNSP charges remain on throughput", because it "has been included as an output in nearly all previous network economic benchmarking studies", and because the data is robust.[55]

However, none of these reasons have any bearing to a DNSP's costs, which would be required for this decision rule to satisfy the opex criteria of the NER.

First, its use as the measured output in customer bills does not mean that the tariff structure is designed in a cost-reflective fashion. In fact, tariff reform is underway in Australia, the US and in other jurisdictions precisely because kWh charges do not reflect the costs that a user places on the distribution system.

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[52] Economic Insights (9 November 2018), Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Annual Benchmarking Report, p.109.

[53] There appears to be at least one discrepancy between the contents of the Shazam code and the description included in the EI benchmarking report. The EI benchmarking report states that each input equation has been estimated separately for all 24 Australian DNSPs. However, the Shazam code, if we have interpreted it correctly, suggests that it has estimated each input equation across the DNSPs, of which there are only 13. EI's reference to 24 DNSPs appears to have been a copy-paste error from similar work it conducted in New Zealand, in which it compared 24 equivalent companies there.

Source: Economic Insights (9 November 2018), Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Annual Benchmarking Report, p.109.

[54] Economic Insights (25 June 2013), Economic Benchmarking of Electricity Network Service Providers, p.7.

[55] Economic Insights (25 June 2013), Economic Benchmarking of Electricity Network Service Providers, p.9.

Second, the historical use of this driver before 2013 does not imply that it has ever been a driver of DNSPs' opex.

Finally, the availability and robustness of a data source is not related to whether the data source helps to explain changes in a DNSPs' costs.

3.1.3. The weights in the MPFP model are artificially constrained to be positive, masking possible misspecification of the model

When calculating the weights to enter into the MPFP benchmarking exercise in its 2014 benchmarking work, EI first experimented with a translog cost function. However, these attempts were "unsuccessful as some outputs had negative first order coefficients".[56] In other words, EI's attempt to calculate weights with a translog function actually found that opex was *negatively* correlated with some of the outputs.

To correct for this shortcoming, EI instead estimated a non-linear regression in which the coefficient on each output is squared, such that the econometric equation estimated is as follows:

$$Y_i = {\beta_1}^2 CN_t * (1 + \delta t) + \cdots + {\beta_4}^2 Energy_t * (1 + \delta t)$$

where Y_i refers to the cost input being estimated and δt represents technological change.

This approach guarantees that each estimated squared coefficient (e.g. ${\beta_1}^2$) is positive. The subsequent steps that EI follows in aggregating and estimating output weights rely on the squared coefficients, which are guaranteed to be positive.

Therefore, even if the true relationship between an output and opex is non-existent or indeed negative, EI's approach would assign positive weight to that driver. Indeed, the fact that EI's first attempt found negative first order coefficients (the details of which do not seem from our research to be published) suggests that some of the relationships included in the MPFP model may be inappropriate, and arbitrarily forced to be positive.

While EI has updated its output weight estimation for its 2018 benchmarking work to reflect updated data, it continues to use the same econometric approach to estimating them.[57]

3.1.4. The MPFP weights are estimated with very little data, suggesting the weights are estimated imprecisely

EI's annex on the MPFP model describes its estimation approach as follows:

> "The input demand equations were estimated separately for each of the […] DNSPs using the non–linear regression facility in Shazam (Northwest Econometrics 2007) and data for the years 2006 to 2017."

With five coefficients (four outputs plus a trend) being estimated on only 12 data points (i.e. 12 years of data for each DNSP), this leaves only seven "degrees of freedom" on which to

[56] Economic Insights (17 November 2014), Economic benchmarking assessment of operating expenditures for NSW and ACT DNSPs, p.12.

[57] Economic Insights (9 November 2018), Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Annual Benchmarking Report, p.109.

estimate the equation.[58] With little variation year-on-year relative to the scale of the DNSP, the resulting estimates are likely to be imprecise.

Furthermore, when combined with the fact that coefficients are guaranteed to be positive, the imprecision of EI's approach may overstate the importance of outputs with little or no true relationship with DNSPs' costs.

3.1.5. Conclusions on the use of the MPFP Model

We have identified several flaws in the AER/EI's use of the MPFP model to determine output weights:

- EI has selected a set of output drivers on a set of criteria which does not relate to DNSPs' costs;
- EI has adopted an econometric technique which guarantees that it will measure positive relationships between those drivers and costs, even where there is no relationship;
- EI may have estimated those relationships with a degree of imprecision that will likely overstate the importance of drivers with little or no true relationship with costs; and
- It has provided insufficient detail for its modelling technique to be properly interrogated, and for the AER to have confidence in the resulting output weights.

Therefore, we conclude that the output weights resulting from the MPFP model as defined are not likely to reflect the true drivers of opex for a DNSP. By indexing DNSPs' allowances to changes in outputs weighted according to this model, the AER will not allow DNSPs to recover the costs that a prudent or efficient DNSP would incur to operate the same system. The MPFP model as presently defined therefore does not satisfy the operating expenditure criteria defined in the NER.

3.2. Energy Throughput is not an Appropriate Measure of DNSPs' Efficient Operating Costs

In the previous section, we identified several technical problems with EI's MPFP analysis that make it inappropriate for calibrating the weight placed on energy throughput in the AER's allowed rate of change. However, aside from these technical problems, a more fundamental problem with the AER's proposal to index allowed opex to changes in energy throughput is that it does not reflect changes in DNSPs' efficient operating costs. Drawing from recent experiences in Australia, Great Britain and the United States, we conclude that industry trends toward embedded generation and load-altering technologies, make energy throughput an increasingly inappropriate output driver.

Indeed, the AER appears to agree that energy throughput is not a driver of DNSPs' efficient operating costs. The AER states in its 2018 Annual Benchmarking Report:

[58] A "degree of freedom" is "the number of quantities that enter into the calculation of a statistic minus the number of constraints connecting these quantities". Source: Kennedy, P (1979), A Guide to Econometrics, p.65.

> "…[E]nergy throughput is not considered a significant driver of costs (distribution networks are typically engineered to manage maximum demand rather than throughput)…"[59]

EI also states in its 2013 benchmarking study for the AER:

> "…[P]rovided there is sufficient capacity to meet current throughput levels, changes in throughput are likely to have at best a very marginal impact on the costs DNSPs face."[60]

DNSPs design their networks to withstand peak demands. Network peak demands, numbers of customers (which influence peak demands), and line lengths, therefore, predict costs better than energy throughput.

Until recently, growth in energy throughput may have approximated growth in peak demand. However, various technological changes in the electricity industry mean energy throughput is no longer a reasonable proxy for distribution costs. Such developments include the deployment of customer-sited solar photovoltaics (PV), electrical storage devices, electric vehicles, and other technologies that alter traditional customer load profiles. Due to the growing use of load-altering technologies, network-wide changes in energy throughput no longer accurately predict proportionate changes in peak demand or distributors' costs.

3.2.1. Australian tariff reform is moving towards cost reflective pricing, which reduces the emphasis on per kWh charges

Consumers in Australia typically pay network charges (through their retailer) on a per kWh basis. However, since 2012, various rule changes and reform efforts have questioned the logic of this approach, on the basis that consumption volume is not a major driver of network costs.

For example, in 2012, the Australian Energy Market Commission (AEMC) undertook its Power of Choice review, which studied the energy market conditions for Demand Side Participation (DSP) with the goal to facilitate the response of electricity consumers to the price of electricity.[61]

The AEMC found that "when a network business develops tariffs which are based on consumption volumes, its profits could depend upon the level of actual volumes [and] the business may have no incentive to pursue any form of DSP project (or energy efficiency project) which decreases volumes".[62] The disincentive is based on the fact that a demand reduction of 1 kWh reduces network costs by less than the reduction in tariff revenue.

The AEMC considered several changes to the regulatory framework which would remove the disincentive for DNSPs to invest in DSP, including the introduction of "cost reflective" pricing (essentially high fixed charges and lower variable charges). Ultimately, it proposed

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59 AER (November 2018), Annual Benchmarking Report – Electricity distribution network service providers, p.51.

60 Economic Insights (25 June 2013), Economic Benchmarking of Electricity Network Service Providers, p.8.

61 Australian Energy Market Commission (30 November 2012), Power of choice review – giving consumers options in the way they use electricity.

62 Australian Energy Market Commission (30 November 2012), Power of choice review – giving consumers options in the way they use electricity, p. 214.

an extension to the demand management incentive scheme incentive scheme (DMIS) in which DNSPs are remunerated for profits lost as a result of reduced electricity consumption. [63]

Following the 2012 review, in 2014 the AEMC carried out a rule change in relation to DNSPs' pricing policies, and set out "new rules that will require distribution network businesses to develop prices that better reflect the costs of providing services to individual consumers."[64]

The policies in place at the time were "dominated by flat volume or inclining block energy prices," meaning that "the price of using electricity at off-peak times is higher than the cost caused by that usage, while the price of using energy at times of peak demand is much lower than the cost".[65]

The AEMC found that:

> "…consumers receive substantial network charge reductions for reducing total usage, even though **total energy usage does not reflect the drivers of network costs.** On the other hand, consumers only receive small reductions in charges from reducing peak usage, even though the costs of providing network services at peak times are high."[66] [emphasis added]

To correct for the disconnect between the drivers of cost (peak demand) and revenue (largely driven by volume), the AEMC implemented several changes to the NER which improve the extent to which tariffs are reflective of the costs consumption imposes on the network. For example:[67]

- The new rules introduced a network pricing objective that "tariffs should reflect the efficient costs of providing network services".
- While DNSPs had previously been required to "take into account long run marginal cost (LRMC) when setting network prices", the new rules require network prices to actually be based on LRMC.

While the updates to the NER left some discretion for DNSPs to design their pricing principles, the AEMC's rule changes emphasise that flat volumetric charges are unlikely to be cost-reflective.

Since then, the 2017 Energy Networks Australia (ENA) and the Commonwealth Scientific and Industrial Research Organisation (CSIRO) Electricity Network Transformation Roadmap have also emphasised the need for network tariff reform, which could "unlock further value

[63] Australian Energy Market Commission (30 November 2012), Power of choice review – giving consumers options in the way they use electricity, p. 218.

[64] Australian Energy Market Commission (27 November 2014), National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 – Rule Determination, p.i.

[65] Australian Energy Market Commission (27 November 2014), National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 – Rule Determination, p.35.

[66] Australian Energy Market Commission (27 November 2014), National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 – Rule Determination. p.36.

[67] Australian Energy Market Commission (27 November 2014), National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 – Rule Determination, Table 1.

from customer investments in distributed energy resources through direct, targeted incentive signals".[68] The roadmap thus sets a milestone that, "by 2021, residential and small business customer are assigned to a new range of cost reflective network tariffs, enabled by a high penetration of smart meters".[69]

The DNSPs in Victoria are currently in the process of redesigning network tariff design for the 2021-25 period. The Victorian DNSPs commissioned consultants at The Brattle Group (Brattle) to advise on tariff objectives and tariff options.[70]

The Brattle report noted that:

> "in most jurisdictions internationally and in Australia, small users have traditionally been charged for their share of network costs based largely on their energy consumption (ie, kWh). However, tariff reform efforts in many jurisdictions are tending to increase the weighting on peak demand and/or fixed daily charges in charging customers for their usage of the network, [resulting in] a network tariff that is more 'cost reflective'".[71]

3.2.2. In Great Britain, Ofgem has stopped using energy throughput to set distributors' allowances

In Great Britain, the Office of Gas and Electricity Markets (Ofgem) has reduced the emphasis on energy throughput when setting distributors' price controls. Unlike the AER, Ofgem does not make separate determinations of base opex and an allowed rate of change. However, the methods it uses to forecast costs include catch-up efficiency targets, allowed rates of change in productivity and input prices, and an adjustment for changes in costs due to changes in outputs.

Over recent price controls, Ofgem has placed less emphasis on energy throughput as a driver of how companies' allowed opex changes within control periods.

- In the past, Ofgem placed significant emphasis on energy throughput. In its "Distribution Price Control Review 4" (DPCR4) that applied from 1 April 2005 to 31 March 2010, Ofgem used an index of network size as the primary driver of distributors' operating costs, measured by three drivers: network length (50 per cent weight), customer numbers (25 per cent weight), and energy throughput (25 per cent weight).[72]
- Ofgem did not use energy throughput in this way at subsequent price control reviews. At DPCR5 that applied from 1 April 2010 to 31 March 2015, citing "widespread concern that [the composite variable used in DPCR4] was an inappropriate cost driver that did not adequately relate to the costs that were being assessed,"[73] Ofgem based efficient opex on

68 ENA & CSIRO (April 2017), Electricity Network Transformation Roadmap: Final Report, p.41.

69 ENA & CSIRO (April 2017), Electricity Network Transformation Roadmap: Final Report, p.42.

70 The Brattle Group (April 2018), Electricity Distribution Network Tariffs – Principles and analysis of options.

71 The Brattle Group (April 2018), Electricity Distribution Network Tariffs – Principles and analysis of options, p.2.

72 Ofgem (November 2004), Electricity Distribution Price Control Review: Final Proposals, November 2004, p.69.

73 Ofgem (2009), Electricity Distribution Price Control Review: Final Proposals – Allowed revenue – Cost assessment, , p.10.

the results of 19 sets of regression analyses using several cost drivers, none of which included energy throughput.[74]

- Similarly, in its "RIIO-ED1" price control that applies from 1 April 2015 to 31 March 2023, Ofgem did not consider energy throughput a driver of opex. Ofgem used three economic models in its benchmarking of efficient total expenditures (totex):[75] a disaggregated activity-based model, a top-down totex model using aggregated cost drivers, and a bottom-up totex model using an aggregated driver based on the drivers used in the disaggregated analysis:[76]
  - The disaggregated analysis incorporated several cost assessment techniques including regression analysis, ratio analysis, trend analysis, and technical assessment, and energy throughput was not considered in any of these techniques a driver of opex.
  - In the top-down totex model, Ofgem regressed costs on a composite variable consisting of Modern Equivalent Asset Value (MEAV), a measure linked to the size and replacement cost of the existing network, and customer numbers.
  - In the bottom-up totex model, Ofgem regressed costs on a range of cost drivers, and did not use energy throughput as a driver of opex.

3.2.1. In the United States, state regulatory commissions are placing less emphasis on energy throughput when setting regulated revenues

Evidence from the US also shows that energy throughput does not reflect distributors' costs. Reviews of regulated rates in the US often include detailed assessment of long-term trends in Total Factor Productivity (TFP) to determine an "x-factor". The x-factor allowed by US regulatory commissions defines the productivity target built into companies' regulated rates.

Indices of TFP measure differences between the growth rates of the outputs and the inputs of a company or group of companies. They require company or industry data that can be used to develop aggregate indexes representing the rate of change in inputs relative to the rate of change in outputs. Data from recent TFP analyses of US electricity distribution companies reveal a growing mismatch between opex and energy throughput.[77] Figure 3.1 shows annual growth rates in a TFP index representing the overall change in electricity distributors' input costs relative to the volume of energy throughput for 65 US distributors, from 1973 to 2017.

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74 Ofgem used the following cost drivers in determining efficient opex in DPCR5: modern equivalent asset value (MEAV) for regressions using top-down (aggregated) cost drivers and disaggregated regressions dealing with all opex categories other than fault-related costs, inspections and maintenance, and tree cutting; load and non-load related capex for disaggregated regressions dealing with one grouping of opex categories (network design, project management, and system mapping); direct costs for disaggregated regressions dealing with two other groupings of opex categories; faults and length of cable replaced for disaggregated regressions dealing with fault-related costs; asset work hours for disaggregated regressions dealing with inspections and maintenance; and spans cut and spans affected for disaggregated regressions dealing with tree cutting-related costs.

Ofgem (December 2009), Electricity Distribution Price Control Review: Final Proposals – Allowed revenue – Cost assessment appendix, p.81.

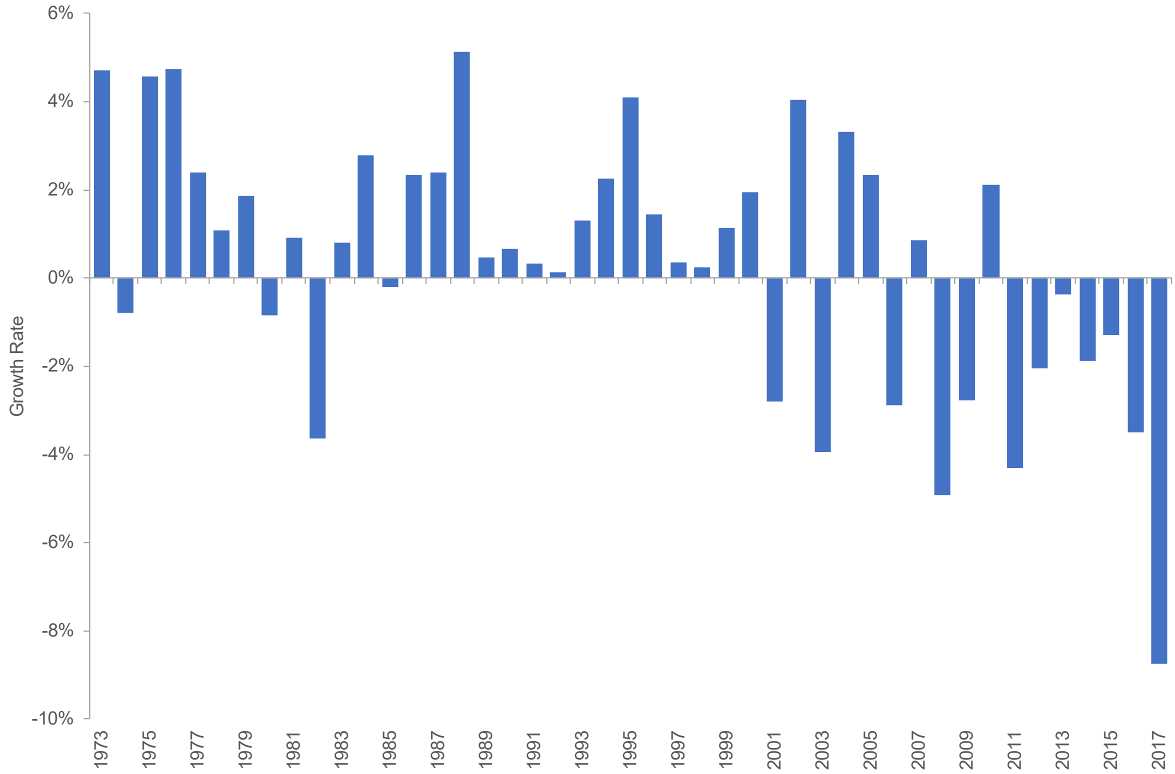
75 As a component of the RIIO-ED1 framework, Ofgem introduced the totex concept to signal to distributors equal opex and capex efficiency incentives. In RIIO-ED1, Ofgem establishes base totex rather than base opex and capex separately.

76 Ofgem (November 2014), RIIO-ED1: Final determinations for the slow-track electricity distribution companies: Business plan expenditure assessment.

77 (1) Makholm, J. D. (2018), The Rise and Decline of the X Factor in Performance-Based Electricity Regulation, *Electricity Journal* 31 (2018), p.38-41; (2) Massachusetts Department of Public Utilities (DPU) (30 November 2017), Order Establishing Eversource's Revenue Requirement, p.370-414.

While the annual rate of TFP growth was consistently positive for the majority of this period, since 2000 the rate of productivity growth (as measured by costs per unit of energy) has declined rapidly.

Figure 3.1: Average Growth in TFP, 65 US Electricity Distributors, 1973-2017



Source: NERA analysis on data from US Federal Energy Regulatory Commission[78]

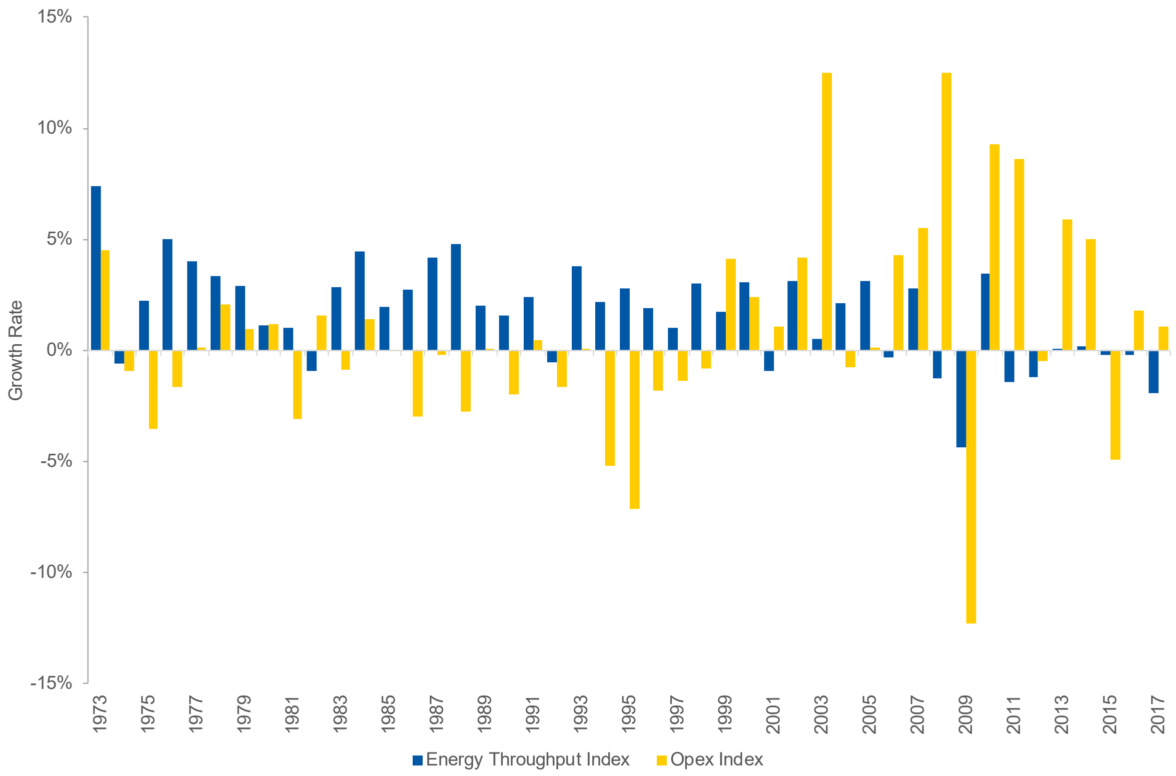
The reason for this change in TFP growth is decomposed in Figure 3.2 into changes in opex and units of energy throughput. Distributors have incurred higher opex over this period, such as related to the deployment of new technologies including smart metering. The percentage of electricity customers with advanced meters grew from 1-2 per cent a decade ago, to more than 40 per cent today.[79] Expenditures for activities related to electric vehicle charging, electrical storage, voltage optimisation, data management, and cybersecurity are now the norm in many US states. Over the same period, the volume of energy supplied has been falling in a way disjoint from changes in distributors' costs:

- From 1973 to 2000, the energy throughput index grew on average by 2.5 per cent each year, and the opex index declined on average by 0.6 per cent each year.
- The relationship reversed and intensified in the 2000s. From 2000 to 2017, energy throughput increased on average by only 0.2 per cent each year (with declines in seven of the last 10 years), and opex increased on average by 3.1 per cent each year.

[78] US Federal Energy Regulatory Commission, Form 1.

[79] US Energy Information Administration Form 861, Years 2007-2017.

Figure 3.2: Average Growth in Energy Throughput and Opex, 65 US Electricity Distributors, 1973-2017



Source: NERA analysis on data from US Federal Energy Regulatory Commission[80]

Recognising a growing mismatch between distributors' expenditure and traditional outputs like energy throughput, US regulators increasingly compensate distributors for alternative outputs linked to emerging policy and regulatory objectives. In New York as part of the "Reforming the Energy Vision" (REV) initiative, the New York Public Service Commission authorised distributors to develop "Earnings Adjustment Mechanisms" (EAMs) that would reward distributors for contributing to peak reduction/system efficiency, energy efficiency, customer engagement, and improvements in the distributed generation interconnection process. Other state regulators are considering compensating distributors for a variety of outcomes including cybersecurity (New Hampshire and Rhode Island), customer engagement/network support (Massachusetts and Rhode Island), demand response programs (Michigan), distributed energy resource integration (Rhode Island), energy and system efficiency (Massachusetts, Pennsylvania, and Rhode Island), and grid modernisation (New Hampshire).

3.2.2. US regulatory commissions are also restructuring regulated revenues to reduce emphasis on per kWh rates, to keep costs and revenues better aligned

The same technological changes that are leading state regulatory commissions to delink regulated revenues from changes in energy throughput are also leading them to reform tariff

[80] US Federal Energy Regulatory Commission, Form 1.

structures to better reflect the cost saved as a result of distributed generators exporting energy to the grid.

Just as energy throughput does not mirror distributor costs, energy exported to the grid by customer-sited generators does not mirror distributor benefits in the form of cost savings. This is apparent in the US where state "net metering" policies that compensate exported generation at a volumetric (dollar-per-kilowatt-hour) retail rate of electricity, drove growth in rooftop solar PV. Under net metering policies, distributors are unable to recover certain costs associated with the delivery of electricity.

Recognising this growing mismatch between utility costs and revenues, many states are in the process of developing net metering alternatives or successors that would enable utilities to recover the appropriate costs from customers with embedded generation. In 2017, 45 US state regulatory commissions and the District of Columbia engaged in 249 actions considering solar PV policy and rate design alternatives to net metering.[81]

3.2.3. Energy throughput and distribution opex may now be negatively correlated

Prior to recent growth in embedded generation and other load-altering technologies, energy throughput and distribution network costs might have been positively correlated. For instance, higher energy throughput might have coincided with higher operating costs due to growth in peak requirements and customer numbers. Growth in embedded generation tends to weaken or eliminate such positive correlation. Hence, while customer numbers and ratcheted peak demand continue to be important cost drivers for distribution networks, energy throughput ceases to be an appropriate proxy for these cost trends.

However, the link between energy throughput and distributors' costs could reverse, with reductions in throughput caused by higher embedded generation imposing additional distribution costs that are not captured by other output drivers.

In particular, we understand from SA Power Networks that, while system peak demand in some areas of South Australia is not growing, localised peak network flows on low voltage (LV) networks are growing, as a result of highly localised export flows from distributed energy. The growing localised peaks result in a need for system reinforcement that would not appear to be justified simply by looking at ratcheted system peak demand or energy throughput.

Reflecting this, in 2015/16, SA Power Networks spent 19 per cent of its capacity augmentation expenditure (Augex) on LV and Quality of Service (QoS) reinforcements to accommodate distributed energy. By 2025, it expects to spend 46 per cent of its Augex on LV/QoS.[82] Requirements for new network assets linked to LV/QoS requirements would impose higher operating costs to maintain these assets that is not correlated with customer numbers, ratcheted peak load, circuit length or energy throughput.

81 Proudlove, A., Lips, B., Sarkisian, D., and A. Shrestha, (January 2018), 50 States of Solar: Q4 2017 Quarterly Report & 2017 Annual Review, NC Clean Energy Technology Center.

82 As advised by SA Power Networks.

The energy throughput driver does not measure energy exports, and so does a poor job of proxying for the extent that network usage drives costs, especially as energy exports become increasingly important.

The AER's approach to quantifying the link between energy throughput and opex is not well-suited to capturing this effect. If energy throughput becomes negatively correlated with distribution costs, the EI/AER MPFP modelling imposes a positive weight by assumption by using squared coefficients (see Section 3.1.3), so it is incapable of capturing this relationship between efficient opex and energy throughput. If the MPFP modelling imposes a positive relationship between opex and energy throughput, where in fact a negative relationship exists, DNSPs' actual efficient costs may exceed efficient costs estimated by MPFP modelling. This could lead to DNSP under-recovery of actual efficient costs, which is inconsistent with the operating expenditure criteria in the NER.

3.3. Translog Model

The AER bases part of its output indexation weights on the econometric output from a translog least squares model. In this section, we appraise the translog model with reference to the appraisal criteria set out at the beginning of this chapter.

As set out below, the AER has derived weights in a way that does not capture the relationship between opex and the output drivers in the translog model specification. When interpreted correctly, the implied relationships between outputs and opex are not plausible from an economic or engineering perspective, so the use of this model is therefore unlikely to satisfy the operating expenditure criteria.

3.3.1. The AER has not considered whether the coefficients in its translog model imply intuitive engineering or economic relationships

As discussed in Section 2.5.4, a translog model differs from a Cobb-Douglas model because the elasticity of opex to output drivers depends on the levels of those drivers. While this method can capture differences in economies of scale for companies of different sizes, the relationships between modelled costs and drivers implied by the model depend on a series of quadratic and cross-product terms in the cost function shown in Table 3.1 below.

Table 3.1: Translog Least Squares Coefficient Estimates

Variable	Coefficient	z-ratio
ln(Custnum)=x1	0.505	6.73
ln(CircLen)=x2	0.136	4.51
ln(RMDemand)=x3	0.340	5.05
x1*x1/2	–0.565	–2.070
x1*x2	0.175	1.84
x1*x3	0.317	1.49
x2*x2/2	0.039	0.91
x2*x3	–0.204	–2.830
x3*x3/2	0.005	0.03
ln(ShareUGC)	–0.159	–5.980
Year	0.018	4.41
Country dummy variables:		
New Zealand	–0.417	–2.320
Ontario	–0.229	–1.280
DNSP dummy variables:		
AGD	–0.126	–0.600
CIT	–0.713	–3.800
END	–0.417	–2.230
ENX	–0.423	–2.190
ERG	–0.443	–2.060
ESS	–0.541	–2.300
JEN	–0.258	–1.410
PCR	–0.940	–4.590
SAP	–0.632	–3.260
AND	–0.460	–2.340
TND	–0.581	–2.830
UED	–0.528	–2.730
Constant	–26.812	–3.190

Source: EI[83]

The estimated coefficients in this relatively complex cost function imply relationships between costs and drivers for which the intuitive reason is neither obvious nor explained by the AER or EI.

[83] Economic Insights (9 November 2018), Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Annual Benchmarking Report, Table 3.5.

To illustrate this problem, consider the effect of an increase in ratcheted peak demand by 1 per cent. The AER's translog model suggests the following relationships apply:

- The coefficient on the ratcheted peak demand variable (0.340) shows that a 1 per cent increase in ratcheted peak demand increases efficient opex by 0.340 per cent;
- The coefficient on the square of the ratcheted peak demand variable (0.005) suggests that the elasticity of opex to ratcheted peak demand *increases* by 0.005 percentage points for every 1 per cent increase in ratcheted peak demand. The low coefficient (which is not statistically significant) indicates almost constant returns to scale for ratcheted peak demand.
- The coefficient on the variable capturing the interaction between ratcheted peak demand and customer numbers (0.317) suggests that for companies with 381,312 customers, the average for all DNSPs in 2017, a 1 per cent increase in ratcheted peak demand would increase opex by 4.07 per cent, in addition to the contribution to elasticity from other coefficients. This elasticity of changes in opex to changes in ratcheted peak demand is higher for companies with more customers. For instance, the elasticity implied by this coefficient for Evoenergy and Ausgrid (respectively the smallest and largest DNSPs by customer numbers in 2017) ranges from 3.86 per cent to 4.55 per cent.
- The coefficient on the variable capturing the interaction between ratcheted peak demand and circuit length (-0.204) suggests that for companies with line length of 56,791 kilometers, the average for all DNSPs in 2017, a 1 per cent increase in ratcheted peak demand would *decrease* opex by 2.23 per cent, in addition to the contribution to elasticity from other coefficients. This "elasticity" of changes in opex to changes in ratcheted peak demand is lower for companies with longer lines. For instance, the elasticity implied by this coefficient for CitiPower and Essential Energy (respectively the smallest and largest DNSPs by line length in 2017) ranges from -1.72 per cent to -2.48 per cent.

These econometric results do not appear to reflect any intuitive engineering or economic explanation. For instance, intuitively, one might expect elasticity of opex to ratcheted maximum demand to actually *increase* in a network with more kilometres of line, because the higher load affects a greater volume of assets. Neither the AER nor EI have provided any explanation of the signs on the second-order conditions.

EI claims to have assessed the coefficients in the round by testing the "monotonicity" of the coefficients, confirming that no DNSP could increase its outputs without increasing its costs.[84] Mathematically, we show this in Equation 2 below, equal to the partial derivative of Equation 1 with respect to output X_1.

(1) $$Y = \beta_0 + \beta_1 X_1 + \beta_2 X_2 + \beta_3 X_2 + \beta_{11}\frac{{X_1}^2}{2} + \beta_{22}\frac{{X_2}^2}{2} + \beta_{33}\frac{{X_3}^2}{2} + \beta_{12}X_1X_2 + \beta_{13}X_1X_3 \ldots$$
$$\ldots + \beta_{23}X_2X_3$$

(2) $$\frac{\partial Y}{\partial X_1} = \beta_1 + \beta_{11}X_1 + \beta_{12}X_2 + \beta_{13}X_3$$

[84] Economic Insights (9 November 2018), Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Annual Benchmarking Report, p.19.

EI's claim of monotonicity implies that Equation 2 is greater than 0 for all three outputs and all 13 DNSPS. We show this not to be true in Table 3.2, which feeds 2017 output levels and the coefficients from Table 3.1 into Equation 2. The table demonstrates that each DNSP could increase customer numbers while *reducing* opex, violating the monotonicity condition.

Table 3.2: Elasticity Estimates Derived from the Full Translog Model

	Cust Number	Circuit Length	RM Demand
EvoEnergy	-2.78	1.26	2.48
Ausgrid	-2.96	1.27	2.76
Citipower	-2.90	1.20	2.69
Endeavour Energy	-2.80	1.25	2.61
Energex	-2.89	1.29	2.66
Ergon Energy	-2.48	1.32	2.23
Essential Energy	-2.57	1.38	2.24
Jemena	-2.95	1.29	2.62
Powercor	-2.73	1.35	2.40
SA Power Networks	-2.68	1.33	2.39
AusNet Services	-2.85	1.37	2.47
TasNetworks	-2.61	1.29	2.31
United Energy Distribution	-2.99	1.29	2.69

Source: EI[85]

Given this more complex cost structure, we would have expected the AER to apply greater scrutiny to the modelled coefficients before combining outputs in the allowed rate of change calculation. In the absence of a rigorous review of the reliability to this model, along with the counterintuitive second-order coefficients, the model as currently estimated does not produce estimates that reliably track DNSPs' cost drivers.

3.3.2. The UK regulatory appeals body has found translog models to be unreliable in the water sector

The UK's regulatory appeals body, the Competition and Markets Authority (CMA), has found similarly implausible modelled relationships between costs and drivers in a translog model estimated by the water sector regulator, Ofwat.

Ofwat set price controls using a series of translog models to model water and wastewater companies' total expenditure (totex) and base total expenditure (botex)[86] at its PR14 price control decision that applies from April 2015 to March 2020. Similar to the AER's translog models, Ofwat estimated translog cost models as a function of, not only the length of mains

85 (1) "DNSPData AusNZOnt 1Nov2018x BM.xls"; (2) Economic Insights (9 November 2018), Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Annual Benchmarking Report, Table 3.5.

86 Base total expenditure refers to the sum of opex and capital maintenance expenditure. It does not include capital enhancement expenditure, such as the construction of new reservoirs. Total expenditure is opex plus total capex, i.e. including both capital enhancement and capital maintenance.

and connected properties per length of main, but also of the square of each of those terms as well as the cross product.[87]

One company, Bristol Water, appealed Ofwat's determination to the CMA. In its decision, the CMA scrutinised Ofwat's econometric models used to assess efficient totex and botex. The CMA raised several criticisms of the Ofwat econometric models and replaced them with its own models.

Among several other criticisms, the CMA found that the translog models involved "relatively complex explanatory variables and it is difficult to interpret the relationships that they imply between costs and explanatory variables in economic or engineering terms".[88]

In short, the CMA came to the same conclusion with respect to the Ofwat models that we have come to with respect to the AER translog model: the translog model as defined does not appear to capture plausible relationships between opex and the drivers of distribution network costs.

3.3.3. Translog model weights should include the second-order terms, but these produce counterintuitive results

As set out above in Section 3.3.1, the impact of changes in outputs on opex is captured by a wider set of coefficients (including on cross-product and quadratic terms), not solely by the coefficients on the individual output terms. However, the AER has proposed to base weights from the translog model on only these "first-order" coefficients (0.507, 0.136 and 0.338 for customers, circuit length and ratcheted maximum demand, as shown in Table 3.1), ignoring the squared and cross-product terms.

Both the squared and cross product terms materially affect the modelled elasticity of costs with respect to changes in output as described in Section 3.3.1. Hence, the AER's proposed output weights are inconsistent with the cost-output relationships estimated by the translog model, shown for output X_1 below.

$$(3)\quad \frac{\partial Y}{\partial X_1} = \beta_1 + \beta_{11}X_1 + \beta_{12}X_2 + \beta_{13}X_3$$

By contrast, the AER defines the output weights equal to β_1 (hypothetically for output X_1), which would only be a correct interpretation of the translog model for a DNSP serving one customer, with one kilometre of circuit, delivering a maximum demand of one MW.[89]

To address this inconsistency, the AER would need to estimate weights which are contingent on output levels using coefficients on all output variables in the model (ie. all terms of Equation 3 above), which we calculate using 2017 output data in Table 3.2. Note that these precise relationships will change as each DNSPs' output levels change.

87 Cambridge Economic Policy Associates Ltd (20 March 2014), Ofwat: Cost Assessment – Advanced Econometric Models, p.59-101.

88 Competition & Markets Authority (6 October 2015), Bristol Water plc – A reference under section 12(3)(a) of the Water Industry Act 1991: Report, para.4.50.

89 Because ln(1) = 0.

However, the output weights resulting from this correction are not plausible. These internally-consistent results imply that a 1 per cent increase in customer numbers would lead to a 2.5 to 3 per cent *reduction* in efficient opex, depending on the size of the network in terms of the three drivers, a result that is not grounded in reality.

Given that correcting the AER's use of the translog model to compute output weights does not yield realistic results, the use of this model would not provide opex allowances that reflect the costs of an efficient distributor operating at the same scale and in the same environment as one of the Australian DNSPs would incur to provide distribution services. Therefore, by indexing allowances to changes in outputs weighted according to the translog model, the AER would fail to satisfy the operating expenditure criteria as set out in the NER.

3.4. Conclusions

As we have demonstrated in previous three sections, the AER's proposed approach fails to set output weights in a way that is likely to keep changes in opex allowances in line with changes in the costs that would be incurred by a prudent or efficient operator:

- The MPFP model is based on a set of output drivers chosen for arbitrary reasons that do not reflect costs, and which is estimated in such a way that guarantees positive weights even when no true relationship exists.
- Energy throughput is not a driver of efficient opex. By indexing opex allowances to changes in this driver, the AER is linking companies' allowances to changes in an index which both fails to reflect their efficient costs and is expected to fall.
- The AER derives weights from the translog model which are not consistent with the estimated econometric model. When corrected, the estimated econometric relationships between costs and drivers are counterintuitive, so the use of this model to set output weights would not produce allowances in line with changes in DNSPs' efficient opex.

Therefore, for these three reasons, the AER's proposed approach does not satisfy the opex criteria included in the NER and is therefore inconsistent with clauses 6.5.6(c) and 6.12.1(4) of the NER.

The CCP10 critique argues that the SFA model places more weight on customer numbers than reflects the reality of the relationship between opex and customer numbers, but has cited only its own knowledge and the econometric results of a regulator in a different country with different conditions and smaller DNSPs. Given the problems with the translog and MPFP analysis, relying on the two Cobb-Douglas models would provide a more robust approach than the AER's current proposals. As such, with the evidence at hand, the CCP10 critique does not appear to merit an arbitrary de-weighting of the customer numbers variable.

Moreover, by failing to remunerate companies for their efficiently-incurred opex, the AER disincentives efficient investment in the network. A DNSP may not make efficient investments in expanding or improving its network if it knew that it would not be fully remunerated for the additional opex that those expansions or improvements would yield. As a result of inefficiently-low investment, future consumers of electricity could see an increase in price and/or a decrease in quality, safety, reliability and security of supply of electricity.

The three components of the AER's approach discussed in this chapter are therefore not in the long-term interests of consumers of electricity, and therefore do not meet the National Electricity Objective, as defined in the National Electricity Law.

4. Recommended Approach to Output Indexation

4.1. A Pragmatic Solution Uses the Cobb-Doulas Models to Set Output Weights

As explained in Chapter 3, the output weights that the AER draws from the MPFP model and the translog model do not reflect how changes in outputs change efficient opex. Therefore, by indexing opex allowances to changes in outputs weighted based on the MPFP and translog coefficients, the AER will not allow DNSPs to recover the opex costs that would be incurred by an efficient operator.

We therefore recommend that the AER excludes these two models from the output weighting process, or else re-design them such that they are consistent with the operating expenditure criteria of the NER. In the case of the MPFP modelling, this may also require the AER to provide greater transparency into EI's modelling, such that it satisfies the requirement in Clause 6.12.2 of the NER to set out details of its quantitative methods.

Alternatively, the AER could exclude these two models and index outputs to weights taken from an average of the Cobb-Douglas SFA and least squares models. Thus, basing output weights on a simple average of the coefficients in these two models may be a proportionate solution to the problems we have identified, and appears to satisfy the operating expenditure criteria and, by extension, the NEO.

The AER's proposal to include the three additional models is a response to (i) the Tribunal decision which criticised the AER for placing excessive weight on a single model; and (ii) the CCP10 submission which argued that the AER placed too much weight on customer numbers. Our proposed approach halves the weight applied to the SFA model relative to the models criticised by the Tribunal, thereby addressing the Tribunal critique. It does place twice as much weight on the SFA model as the AER's current proposal does, but the AER's current approach does not effectively address the Tribunal's criticisms by including additional models which *do not* track changes in efficient opex.

The weight applied to customer numbers, which the CCP10 questioned, is similar across the two models (71 per cent in the SFA model and 0.68 per cent in the least squares model). These weights are also lower than the 77 per cent implied by EI's 2017 SFA model, so this approach is consistent with the CCP10 recommendation. However, the CCP10's criticism that the previous SFA model overstated the importance of customer numbers in driving efficient opex was not supported by any evidence, other than a reference to practice in New Zealand. Hence, it is not clear how the recommendation to reduce weight on customer numbers would be consistent with the operating expenditure criteria in the NER.

4.2. Energy Throughput is Not a Suitable Driver of Efficient Opex

As discussed in Section 3.2, DNSPs' efficient opex is not driven by the volume of energy throughput. Notwithstanding that we recommend that the AER exclude the only model that uses energy throughput as a driver (the MPFP), we recommend that the AER should not include energy throughput in any future alternative output indexation approach.

Energy throughput does not drive efficient opex. Rather, it is expected to fall in the subsequent price control, with increased penetration of distributed energy, while DNSPs' opex may rise as a direct result of the increased penetration of renewable energy.

Instead, the AER could consider how it can adapt its models to reflect the additional costs imposed on distribution networks by distributed and renewable energy which are not captured by the set of output drivers included at present. Depending on the data available to the AER and relevance and significance of each driver to efficient opex, the AER could consider including measures such as network export capacity to accommodate distributed generation or measures capturing the volume of embedded generation. However, we have not appraised the viability of any such driver within the context of this report, which will depend on the availability of data and the AER's ability of calibrating a link between these alternative output measures and DNSPs' opex.

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NERA Economic Consulting
One International Towers Sydney
100 Barangaroo Ave
Sydney NSW 2000
+61 2 8864 6535
www.nera.com