Appendix 5.2: Competition Economists Group report on declining customer impact on operating expenditure

Revised 2026–31 access arrangement information

ACT and Queanbeyan-Palerang gas network access arrangement 2026–31

Submission to the Australian Energy Regulator

January 2026

Declining customer impact on operating expenditure

A report for Evoenergy

January 2026

Prepared by:

Tom Hird and Ker Zhang

Prepared for:

Evoenergy

COMPETITION ECONOMISTS GROUP

Table of contents

List of tables

List of figures

List of abbreviations

CN	Customer numbers
EVO	Evoenergy
MEAV	Modern Equivalent Asset Value
Opex	Operating expenditure
PPF	Partial productivity factor
RAB	Regulatory asset base
VIF	Variance inflation factor

1 Executive Summary

1. Evoenergy (EVO) has commissioned CEG to advise on how, and whether, historical benchmarking models can be used to forecast EVO's operating expenditure (Opex) in a forecast environment where customer numbers and gas throughput decline materially, but the physical scale of the network (mains length) does not decline in a corresponding way. The core forecasting challenge is that meaningful reductions in physical scale generally require coordinated, geographic decommissioning and regulatory approval; they do not occur automatically, or proportionately, simply because customers and throughput fall.

2. The AER's draft decision approach is to forecast Opex by taking forecasts for mains length, customer numbers and throughput and then applying those forecast changes to a suite of historical econometric models developed for gas distributors. Those models typically produce: (i) output coefficients (weights) on each output variable, (ii) an implied degree of economies of scale (the sum of the output coefficients), and (iii) a time trend (often interpreted as underlying productivity change). The AER is forecasting material declines in customer numbers and throughput over the forecast period, while forecasting mains length to remain essentially flat.

1.1 Why applying those models mechanically is not robust for EVO

3. The econometric studies were estimated over historical periods where the key "output" variables (mains length, customer numbers and throughput) moved closely together (especially customer numbers and mains length with correlation coefficient of 0.91). In that setting, multicollinearity means that models can fit historical data well but still struggle to identify the true, separate contribution of each output to cost. The problem becomes acute when the forecast paths decouple, as in EVO's case. If the variables no longer move together, then the individual output coefficients cannot safely be treated as reliable estimates of causal "weights" for forecasting, because the underlying econometric identification relied on historical co-movement rather than clean independent variation.

4. A second, compounding issue is that the time trend in these regressions is also unstable in the presence of multicollinearity. When outputs trend up and Opex per unit of output trends down, the regression can fit very similar histories using different combinations of parameters. For example, it can attribute the observed pattern to strong economies of scale (a low sum of output coefficients) and a relatively modest negative time trend, or instead to weaker scale economies (or even diseconomies) coupled with a more strongly negative time trend. This parameter trade-off means that the time trend and the implied returns to scale are not independently well-identified. As illustrated in Figure 5-5 in section 5.3 below , time trend estimates tend to be more negative where the sum of output coefficients is larger, and less negative where the sum is smaller. That is a symptom of the model substituting between these parameters to fit the same broad historical patterns.

5. This matters for EVO because its network scale is effectively static in the forecast period: there is no material reduction in mains length until coordinated decommissioning becomes feasible. In that environment, models that combine high output coefficients (weak economies of scale or diseconomies) with a strongly negative time trend will mechanically drive Opex down sharply. This is above and beyond any forecast Opex savings from high weights on customer numbers or throughput. The forecast becomes "punitive" not because there is strong evidence of large achievable productivity improvements, but because the model specification can replicate history by offsetting high output sensitivities with an aggressive time trend, and then applies that time trend into a forecast environment where scale growth is not present to moderate its effect. In practical terms, these models tend to push Opex down through both channels at once: the modelled effect of declining

customer/throughput variables and the modelled effect of assumed productivity improvement, even though the underlying asset footprint being operated and maintained is largely unchanged.

1.2 Economic fundamentals and international precedent point the other way

6. Absent usage related "wear and tear" as a driver of opex, the operating and maintenance costs of networks are driven by the scale, complexity and condition of the assets that must be operated and maintained, and by safety and reliability obligations, rather than utilisation metrics per se. In gas distribution in particular, there is no obvious "wear and tear" mechanism comparable to roads: gas flow does not degrade pipes in proportion to throughput, so a decline in throughput does not itself reduce the core obligation to inspect, monitor, respond to incidents, maintain pressure control equipment, and manage corrosion and leaks across the same physical network.

7. This logic is reflected in overseas regulatory approaches. In the UK, Ofgem's gas distribution cost modelling has long relied on a proxy for network scale and complexity (Modern Equivalent Asset Value) rather than customer counts or throughput. Under that framework, a falling customer base does not mechanically imply falling Opex unless the asset base being maintained reduces. In New Zealand, the Commerce Commission has explicitly applied a zero Opex partial productivity factor in the current transition context.

1.3 Implications for the AER's approach to EVO

8. Taken together, the statistical identification issues, economic fundamentals and international precedent suggest that the AER should be cautious in treating historical econometric coefficients and time trends as reliable inputs for forecasting EVO's Opex in a decoupling scenario. The most defensible approach is to anchor forecasts to a measure of network scale (for the AER's available variables, mains length is the closest proxy to an asset-scale driver), treat customer/throughput metrics as secondary until decommissioning is feasible, and avoid imposing aggressive negative time trends that are not robustly identified. Finally, the transition setting may create incentives for efficient Opex/capex substitution (life-extension maintenance and targeted remediation to avoid stranding long-lived replacement capex in areas expected to close), which further weakens any presumption that falling utilisation should translate into falling Opex in the near term.

2 Introduction

9. Evoenergy (EVO) has commissioned Competition Economists Group (CEG) to provide advice on the extent to which past benchmarking analysis can be used to forecast EVO's operating expenditure (Opex) in the context of declining customer numbers and gas throughput but with no similar fall in the scale of the network being maintained

10. This report has the following structure:

    a. Section 3 summarises the AER draft decision;

    b. Section 4 describes Ofgem modelling of Opex and how this fits with an economic/engineering fundamentals approach;

    c. Section 5 critiques the draft decision's statistical and economic interpretation of the regressions on which it is relying. It explains: that multicollinearity is a severe problem within the data and why the draft decision's solution to this problem actually exacerbates the problem;

    d. Section 6 concludes that, ultimately, the forecasting challenge facing the AER can't be resolved statistically (with the available data) and needs to be informed by an engineering assessment of cost drivers (similar to that embodied in Ofgem's approach);

    e. Section 7 describes how, in this context, we consider that the regressions relied on by the AER can best be used.

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3 AER draft decision

3.1 AER draft decision approach

11. The AER's draft decision forecasts Opex based on the following forecasts for mains length, customer numbers and gas throughput.

Table 3-1: Reproduction of AER Table 3.6

Table 3.6 Forecast growth in individual output measures, %

	2026–27	2027–28	2028–29	2029–30	2030–31
Evoenergy proposal					
Customer numbers	–4.3	–6.8	–7.9	–8.7	–9.2
Mains length	0.1	0.1	0.1	0.1	0.1
AER alternative estimate					
Energy throughput	–1.4	–4.3	–4.5	–5.1	–5.6
Customer numbers	–5.1	–3.1	–3.6	–4.1	–4.7
Mains length	0.1	0.1	0.1	0.1	0.1

Source: Evoenergy, *Attachment 4 – Operating expenditure*, June 2025, p. 16; AER analysis.

12. Critically, the AER is forecasting customer numbers and throughput to decline at around 4% per annum. This is a consequence of ACT Government policy restricting new gas connections and encouraging existing gas customers to electrify their appliances.[1]

13. However, there is no similar decline in the scale of the network being used to serve those customers/throughput. Such reduction in network scale will only be achievable once customer density falls below a certain point and regulators allow EVO to switch off supply to given regions. That is, the scale of the network being maintained will only fall when residual customers in a network area are forced to electrify by having gas supply denied to them. Currently, customers are only being encouraged to electrify.

14. This is seen in the fact that the AER is forecasting EVO's mains length to be stable (grow at 0.1% pa) despite customers and throughput declining materially.

15. The AER has plugged its forecasts of these variables into a number of different models developed for gas distributors in the past that attempt to estimate the impact of growth in these "output" variables on total Opex historically. These models estimate:

    a. A weight on each "output" that estimates, other things equal, how historical Opex for gas distributors has moved with that "output". For example, a model might predict that Opex increases by X% of the growth in mains length and Y% of the growth in customer numbers and Z% of the growth in throughput.

    b. An estimate of the economies of scale in providing Opex. If the weights add up to 1.0 then there are no economies of scale. If the weights (X+Y+Z) add up to more (less) than 1.0 then there are diseconomies of scale. For example, if the weights add up to 0.5 then, even if all of the variables

[1] https://energy.act.gov.au/our-pathway-to-electrification/

are growing at 2% per annum Opex is estimated to only increase at 1% per annum (other things equal).

c. An estimate of the time trend in Opex. For example, a time trend of negative 1% would imply that Opex is estimated to fall at 1% per annum above and beyond any effects associated with output changes.

16. The AER has essentially taken its output growth forecasts (from Table 3.6) and plugged them into the benchmarking models previously submitted by gas distributors. Specifically, taken output growth forecasts for EVO and applied the output weights, scale economy estimates and time trend estimates from these historical models. The AER's results are summarised in Table 3.5 of its report (note that "productivity growth" in this table combines both time trend and scale economy effects).

Table 3-2: Reproduction of AER Table 3.5

Table 3.5 Comparison of forecast output growth net of productivity growth

Model specification	Output growth	Productivity growth	Output growth net of productivity growth
Proposed approach	**–0.32%**	**0.00%**	**–0.32%**
ACIL Allen (2016)	**–0.35%**	**0.29%**	**–0.64%**
Economic Insights (2015)	3.74%	3.05%	0.69%
ACIL Allen (2016)	–0.33%	0.32%	–0.65%
Economic Insights (2016)	–1.32%	–0.05%	–1.27%
Economic Insights (2019)	–1.98%	–0.19%	–1.80%
ACIL Allen (2022)	–2.08%	–0.17%	–1.91%
CEG (2024)	**–1.93%**	**0.46%**	**–2.39%**
Minimum			**–2.39%**
Maximum			**–0.64%**

Source: Evoenergy, *Attachment 4 – Operating expenditure*, June 2025, p. 16; AER analysis.
Note: We have only included the results of those studies that reliably estimated individual parameters (that is, the estimated coefficient is of the expected sign) in forming the reasonable range. Consequently, we have excluded the results from Economic Insights (2015) and Economic Insights (2016), which are highlighted grey.

17. EVO proposed Opex would fall by 0.32% per annum. The AER rejected this approach on the basis that -0.32 fell outside a "reasonable range" of -0.64% to -2.39% defined by predictions from select regressions models.[2]

> *When we compared average annual output growth net of productivity growth using Eveoenergy's approach against the forecasts based on each of the available econometric studies, we found it to be higher than the top of the reasonable range formed by the studies, as shown in Table 3.6. Consequently, we are not satisfied that Evoenergy's forecast of output growth, net of productivity growth, is consistent with the NGR requirements for forecasts.*

18. This reasonable range was arrived at after the exclusion of the two highlighted models (EI 2015 and EI 2016) on the basis that these two studies did not have reliably estimated individual parameters – with some "output" weights being negative (e.g., implying Opex fell as that "output" increased).

[2] AER draft decision, page 16.

19. We note that the NZCC has, in November 2025, made a draft decision for New Zealand gas distributors that, if applied to EVO and the AER's forecasts of outputs, would result in a decline in Opex of only 0.495% pa (before the impact of real input cost increases or Opex for Capex substitution). This is above the bottom end of the AER's "reasonable range" (i.e., -0.49% is greater than-0.64%).

20. This specifically reflects the NZCC's view that[3]

> *3.53. We have applied an Opex partial productivity factor (PPF) of 0%. This decision draws on recent trends in measured productivity, **consideration of the prospect of Opex-capex substitution and the wider context of a declining gas market**.*

21. Similarly, Ofgem's modelling approach, discussed in more detail in section 4 below, would be unlikely to result in any reduction in Opex for EVO.

22. These data points suggest that the bottom (and top) ends of the AER's reasonable range may not be reliably estimated.

3.2 AER draft decision commentary on EVO proposal

23. The AER draft decision summarises EVO's proposal as follows.

> *Evoenergy noted that the modelled relationship between Opex and outputs has been informed by data over a period when outputs have been growing. In its view, the historical relationships cannot be reliably assumed to apply when output is falling. It considered that the relationship between Opex and output is likely asymmetric. It stated that once in place, the network must be operated and maintained. It considered that Opex savings are unlikely to be realised until a coordinated, geographic-based approach to decommissioning the network is implemented. Under the ACT Government's Integrated Energy Plan phased decommissioning of the gas network is not expected to commence until 2035.*

24. The AER then correctly describes the statistical theory that EVO was relying on to support its proposal.

> *The econometric modelling results statistically establish a historical relationship between Opex and the set of cost drivers specified. However, the presence of multi-collinearity in some of the cost drivers may not allow us to reliably estimate individual parameters. Where the pattern of multicollinearity remains the same, this is not a concern for forecasting Opex. However, this is no longer the case for Evoenergy's forecast period, as the increasing rate of electrification has affected the different cost drivers to a varying extent.*

25. That this multicollinearity problem is severe is established in detail in section 5.1. In summary, there is severe multicollinearity between mains length and customer numbers (the two "outputs" all regressions include). For example, regressing customer numbers on mains length results in a 0.93 R-squared. Other standard tests identify that the multicollinearity is "extreme".

26. Unfortunately, the draft decision sets out a demonstrably wrong description of how this statistical problem can be solved and, in doing so, arrives at an economically unsupportable forecast of EVO's Opex. The reasons for our conclusions are set out in the rest of this report. However, for the reader's

[3] Gas DPP4 reset 2026, Default price-quality paths for gas pipeline, businesses from 1 October 2026, Draft decision - reasons paper, 27 November 2025, para 3.53. The same draft decision states that they adopt a scale elasticity of 0.445 (which implies a 1.00% reduction in scale reduce Opex by 0.445%. It also states that line length and customer numbers will be given equal weight as outputs but line length will be assumed to not fall with customer numbers. As a consequence, if applied to EVO this would be equivalent to assuming a zero time trend and a coefficient on both customer numbers and mains length of 0.50*0.445=0.225. See Draft decision reasons paper – Attachment C para C133.

convenience we extract the AER draft decision's full reasoning (which follows directly from the above quote).

> *As a result, we consider that only models with reliably estimated individual parameters (that is, where the estimated coefficient is of the expected sign) can be used to forecast Opex. This ensures that the change in each individual driver is incorporated correctly into the overall impact. On this basis, we have excluded models with monotonicity violations.*[49]
>
> *We disagree with Evoenergy's view, however, that the econometric models only capture the relationship between Opex and outputs when outputs are increasing. The Opex model is a short-run variable cost function model, which estimates Opex changes with output changes, quasi-fixed capital input, and other relevant operating environment factors. The Opex relationship with individual outputs in the short run is not considered asymmetric. For the given capital input, the variable cost (that is, Opex) is assumed to change in proportion to an output, regardless of whether the Opex is increasing or decreasing.*
>
> *In considering the role of the econometric modelling results, we noted that all the econometric studies include the regulatory asset base (RAB) as a proxy for the fixed capital input. We have considered the role of forecast RAB values in forecasting output and productivity growth in the context of accelerated depreciation. Where there is any accelerated depreciation the associated decline in RAB values would not reflect a decline in the fixed capital input. We note that the models estimate a positive relationship between RAB and Opex, but an increase in fixed capital would be expected to reduce Opex, all else equal. This suggests that the RAB variable may be capturing some of the output or network effect. For forecasting Opex, we have assumed no Opex–capital substitution by assuming the RAB is held constant. (And thus, forecast Opex is unimpacted by accelerated depreciation or any other changes in RAB.) The assumed zero growth is between increasing mains length and declining energy throughput, maximum demand and customer numbers. Consequently, zero growth is within the range (and most likely on the lower end) of the missing output dimension.*
>
> *Consequently, we are satisfied that our standard approach remains a reasonable basis for forecasting output growth and is more robust than assigning output weights based on judgement. We consider it to be the best approach available in the circumstances.*

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4 Ofgem regulatory precedent

27. In section 6 we will explain the statistical and economic flaws in the passages of the draft decision extracted at paragraph 25 immediately above. However, before doing so it is useful to set out precedent for how Ofgem has dealt with the issue of forecasting Opex

4.1 Ofgem's MEAV cost driver

28. Ofgem's historical Opex modelling differs from the AER in that, for the last decade, Ofgem has already moved away from simple usage, customer counts or mains length as cost drivers and, instead, has used the network's asset base via MEAV (the Modern Equivalent Asset Value) to scale costs. Simply put, MEAV is the cost of creating the same network in today's terms and is explicitly stated to be used as "a proxy for network scale"[4] in fitting cost models.

29. More explicitly, the glossary of Ofgem's RIIO-2 Gas Distribution Price Control – Regulatory Instructions and Guidance defines MEAV as follows:

> *The Modern Equivalent Asset Value is the cost of creating an equivalent new network and essentially captures a weighted average of the Licensees asset volume. The MEAV for the Licensees is calculated from reported assets in the business plan data templates and the new build unit cost for the following assets:* [5][6]
>
> *• LTS assets; • NTS offtakes; • Distribution network embedded gas entry points; • PRSs; • AGIs; • Capacity and storage assets; • Distribution mains;• Governors;• Number of services; and • Multiple occupancy buildings (MOBs) supply infrastructure.*

30. The RIIO-GD3 draft determination explains that MEAV is the core "scale driver" in the econometric model, reflecting each GDN's size and complexity. Ofgem notes that MEAV "best reflects the complexity within each network" and has a strong relationship with costs that is not otherwise explained by other variables, stating: [7]

> *Modern Equivalent Asset Value (MEAV) continues to be our preferred scale driver in RIIO-GD3, as we consider it to best reflect the complexity within each network. We think network scale and complexity has a strong relationship with a lot of the GDNs' underlying cost base, not otherwise explained by workload or other scale drivers. WWU supported this position in its Business Plan, noting that it did not consider any of the potential alternative scale variables (eg network length, customers number or throughput) to be an improvement on MEAV.*

31. Ofgem repeated this view in its recent (Dec 2025) RIIO-3 Final Determination: [8]

[4] Ofgem RIIO-3 Final Determination – December 2025 (paragraph 5.266) available at: https://www.ofgem.gov.uk/sites/default/files/2025-12/RIIO-3-Final-Determinations-GD.pdf

[5] RIIO-2 Gas Distribution Price Control – Regulatory Instructions and Guidance – March 2025 (page 165) available at: https://www.ofgem.gov.uk/sites/default/files/2025-03/RIIO-GD2%20-%20Regulatory%20Instructions%20and%20Guidance%20version%201.17%20clean.pdf

[6] LTS - Local Transmission System is the pipeline system operating at >7 barg that transports gas from NTS offtakes to distribution systems. MTS offtakes - Capital expenditure associated with construction of a new connection and offtake site directly from the National Transmission System as well as modifications/upgrades to existing offtakes. PRS - A pressure reduction station having an inlet pressure greater than 7 bar. AGI - Above Ground Installation - a defined site which does not include pressure reduction equipment, for example a block valve installation.

[7] Ofgem RIIO-3 Draft Determinations – July 2025 (Paragraph 5.203) available at: https://www.ofgem.gov.uk/sites/default/files/2025-06/Draft-Determinations-Gas-Distribution.pdf

[8] Ofgem RIIO-3 Final Determination – December 2025 (paragraph 5.275) available at: https://www.ofgem.gov.uk/sites/default/files/2025-12/RIIO-3-Final-Determinations-GD.pdf

> *We think network scale and complexity have a strong relationship with the majority of the GDNs' underlying cost base, not otherwise explained by workload or other scale drivers. We continue to think MEAV is the best way to reflect the complexity within each network* ***and performs better than other scale drivers (e.g. network length or customers numbers****).*

32. Because Ofgem's cost models are driven by network scale (MEAV) rather than customer counts, a falling customer base does not reduce the allowed Opex unless it also reduces the number of assets being maintained (noting that each asset makes a contribution to MEAV according to its replacement cost). In effect, distributors must still operate and maintain the same pipeline network until it is retired.

33. This is true notwithstanding that Ofgem is projecting declines in usage and customer numbers. In planning documents for the next regulatory period (RIIO-3, 2026–2031), Ofgem states that they:

> *…expect natural gas demand to decline to meet our statutory net zero target and five-year carbon budgets.*[9]

34. This expectation is already visible in market conditions with Ofgem observing that demand for new gas connections has fallen, noting that:

> *Demand for connections has decreased due to a decline in gas boiler demand, influenced by legislation phasing out their installation, rising energy costs, and growing climate change awareness.*[10]

35. As gas demand dwindles, the cost of the existing gas distribution infrastructure will be spread across fewer customers. Ofgem has explicitly states that there is a

> *…risk that a smaller number of future natural gas consumers could be left repaying the largely fixed cost of historical and ongoing network investment.*[11]

36. Notwithstanding falling throughput and customer numbers, Ofgem does not expect this to result in any expenditure savings until utilisation falls to levels that justify decommissioning specific network areas.

> *We consider that the nature of totex spend, which predominantly relates to repeatable and/or core activities, is unlikely to change significantly in the next few years following the end of the current price control in 2026. Customers will continue to pay for a network of a similar scale to that in place today. The nature of the operational risks may change, as the balance between gas and electricity continues to change, and longer-term direction for the network becomes clearer.*[12]

37. Importantly, because Ofgem already benchmarks gas distribution costs against the physical asset base rather than customer numbers or throughput, the UK does not need to modify its regulatory metrics to deal with falling customers and throughput, the framework is inherently robust to customer decline.

38. Therefore, if a GDB like EVO were regulated by Ofgem, its Opex allowance would not fall simply because customer numbers decline because the MEAV approach would recognise that the underlying assets and the obligation to maintain them remains unchanged.

[9] Ofgem RIIO-3 Sector Specific Methodology Decision – July 2024 (paragraph 4.38) available at https://www.ofgem.gov.uk/sites/default/files/2024-07/RIIO_3_SSMD_Overview.pdf

[10] RIIO-2 Gas Distribution Annual Report: 2023/24 (page 12) available at: https://www.ofgem.gov.uk/sites/default/files/2025-04/GD2%20Annual%20Report%202023_24.pdf

[11] Ofgem RIIO-3 Sector Specific Methodology Decision – July 2024 (paragraph 4.38) available at: https://www.ofgem.gov.uk/sites/default/files/2024-07/RIIO_3_SSMD_Overview.pdf

[12] Ofgem Open Letter on Future of Gas Price Controls – July 2023 (Paragraph 2.7) available at: https://www.ofgem.gov.uk/sites/default/files/2023-07/FSNR%20Open%20Letter%20on%20Gas%20Price%20Control.pdf

4.2 Ofgem's MEAV approach supports giving most weight to mains length

39. If one accepts Ofgem's view that MEAV is the preferred measure of network scale and complexity, then among the simpler proxies available to the AER (line length, customer numbers or gas throughput) the proxy that comes closest to MEAV is unquestionably line length. MEAV is fundamentally a valuation of the physical asset base (pipes, valves, joints, pressure-control equipment and associated infrastructure).

40. Line length is likely to be strongly related to MEAV. Specifically, neither MEAV nor line length will fall materially until network regions are decommissioned. MEAV is, in effect, a weighted average of line length and all other physical assets (weighted by replacement cost). MEAV is, therefore, both dominated by line length (as the most expensive asset category for a GDB) and will move more or less in proportion to line length – with both line length and MEAV tied to the extent of the network assets that must be operated, inspected, and maintained. Line length is, therefore the most conceptually aligned proxy for MEAV when MEAV itself is unavailable. EVO's MEAV will only decline when it begins to decommission areas of its network at which point, MEAV and line length will fall together.

41. By contrast, customer numbers and throughput are only related to the underlying asset base to the extent that they:

    a. explain its growth to its current size; and

    b. predict the future decommissioning of network regions (with a material lag)

42. For regulators such as the AER who, unlike Ofgem do not maintain MEAV as an explicit scale driver, the economically consistent approach is to weight Opex allowances primarily on line length rather than customer numbers or throughput. This avoids the error of mechanically reducing Opex forecasts simply because customer numbers are falling, when the physical network (and therefore the cost burden) is unchanged.

4.3 Economic and engineering fundamentals

43. Ofgem's approach is consistent with, what we regard as a reasonable presumption, that operating and maintenance costs of infrastructure networks are driven primarily by the scale, age and complexity of the physical assets that must be operated and maintained. To the extent that there is usage related "wear and tear" that gives rise to higher operating costs then that would also be a secondary factor to consider. But absent such "wear and tear" cost drivers the presumption must be that only changes in network scale (not usage) will drive changes in operating and maintenance costs.

44. Put simply, once infrastructure is in place, the costs required to keep it safe, reliable and compliant are largely determined by the existence of the assets being maintained - not by the number of users or the volume of usage.

45. In a report for Infrastructure Australia, GHD identified the following "key drivers" of renewal and maintenance expenditure:

    a. Scale and extent of the assets (page 45)

        Capital expenditure is a key driver of maintenance expenditure. As new assets come online, the ongoing maintenance liability will generally increase. An exception to this general trend is where renewals replace assets approaching the end of their useful life.

    b. Reliability and environmental standards (page 4)

> *Often, energy, water and transport service providers incur renewals and maintenance costs to meet legislative requirements, environmental standards, safety standards or conditions outlined in the service providers operating licence. The common theme is that the expenditure is non-discretionary.*

a. The age profile of assets (page 24); and

> *Generally speaking, the combination of climate change, expectations of improvements in the level of service offered by infrastructure, and the age profile of infrastructure assets is likely to place upward pressure on future maintenance requirements and expenditure.*

b. Other key drivers identified included climate variability and climate change, the level of input costs and the availability of funding to perform the maintenance.

46. For some networks, such as road and rail, maintenance costs will be a mix of costs determined by the scale/age/complexity of the network and usage related costs (e.g., per tonne kilometre movements). Scale/age/complexity costs will be driven by the number of bridges and intersections, traffic signalling systems and the surrounding environment.

47. Heavier traffic volumes incur "wear and tear" on assets and bring forward the timing of replacement (capex) and some maintenance activities. However, a substantial portion of road maintenance expenditure—such as inspections, vegetation management, drainage, signage, lighting and safety systems—must be incurred regardless of whether traffic volumes are rising or falling. A lightly used road still needs to be inspected, maintained and kept safe for users. A lightly used road will also degrade over time purely due to age and environmental (non-traffic) stressors.

48. Moreover, the "wear and tear" usage costs will be a lagging driver of maintenance costs. That is, in any given year, maintenance expenditure will be addressing wear and tear that has accumulated over the last several years or decades. If usage suddenly halves usage related maintenance costs will not only drop with a substantial lag. Put simply, this year's maintenance program is not repairing wear and tear from last year. It is repairing accumulated wear and tear from the past "n" years – where "n" might to 5 to 10 years. A halving of usage in one year will only show up in a halving of usage related costs after "n"years

49. Of course, different types of infrastructure assets will have different levels of usage versus scale/age/complexity costs. For example, consider building maintenance, some fraction of operating costs are driven by the number of people in the building – such as wearing out carpets or lift buttons. For these types of costs, the density of customers per floor are likely to be important. But most maintenance costs will be driven by the need to maintain safety and security (e.g., onsite security staff), maintain the external grounds and façade and internal utilities such as air conditioning and heating. None of these wear out faster the more densely the building is occupied.

50. For gas distribution networks, we are unaware of any credible evidence that suggests that usage is a significant driver of operating costs (above and beyond the fact that more users drive more network assets to be maintained). For gas distribution networks the dominant drivers of operating costs are activities such as pipeline inspections, leak detection and repair, corrosion management, pressure regulation, emergency response capability, safety compliance, asset monitoring and system control. These activities are driven by the kilometres of pipe in the ground, the number of pressure regulating assets, valves and meters, and the geographic spread of the network. They are not driven by how much gas happens to flow through those pipes, nor by the number of customers connected at a particular moment.

51. Unlike roads or railways, gas networks do not experience physical wear and tear as a function of throughput. Gas flowing through a pipe does not degrade the pipe. A pipeline carrying low volumes

of gas must be inspected and maintained to the same safety standards as a pipeline carrying high volumes. From a safety perspective, lower utilisation does not relax the obligation to ensure network integrity; the same assets remain pressurised and pose the same potential risks if not properly maintained.

52. For this reason, there is no obvious reason to believe that reductions in customer numbers or gas throughput will translate into commensurate reductions in operating costs in the short to medium term. Operating expenditure can only fall materially once physical assets are decommissioned—that is, when entire sections of the network are taken out of service, isolated, and no longer require ongoing maintenance. Until that point, the same network footprint must continue to be operated safely and reliably for remaining customers.

53. This creates an important asymmetry between network expansion and network contraction. When customer numbers grow, new connections often require extensions of the physical network, increasing both usage and asset scale together. In contrast, when customers disconnect in an uncoordinated manner, as occurs during an early-stage energy transition, the physical network does not shrink. The asset base remains largely unchanged even as usage declines. Economic and engineering fundamentals therefore imply that operating costs will remain broadly stable until disconnections become sufficiently concentrated, geographically and temporally, to permit coordinated decommissioning of infrastructure.

54. In this context, forecasting operating expenditure based mechanically on declining customer numbers or throughput risks conflating usage metrics with cost drivers. Such an approach implicitly assumes that operating costs vary proportionally with demand, when in reality they are likely dominated by fixed and quasi-fixed obligations associated with maintaining a given network scale. This is consistent with Ofgem's approach. Sound economic reasoning would seem to require that operating cost forecasts be anchored to the size of the infrastructure being maintained, not to measures of utilisation that can decline independently of that infrastructure.

55. In fact, it seems likely that in the presence of falling customer numbers and usage a gas distributor will sensibly and efficiently attempt to substitute Opex for capex to the extent that this reduces asset stranding when that specific network area is decommissioned. For example, consider mainline valves and sectionalising valves. Replacing a buried valve is expensive (excavation, traffic management, reinstatement). If the network is expected to be in operation for the life of the replacement then, at some point, it will be NPV positive to replace the valve rather than to have more frequent maintenance. However, once decommissioning of that area of the network is expected prior to the end of the life of the valve the calculation changes and it can be lower NPV to increase maintenance costs and avoid replacement costs.[13]

56. Similarly, consider leak management on older or higher-risk mains and services. A permanent solution may involve replacing a length of pipe (or undertaking a broader mains replacement program), which can be NPV-positive when the asset is expected to remain in service for its full

[13] Mainline valves / sectionalising valves are isolation valves installed on distribution mains to allow operators to shut off (isolate) sections of the network for safety, emergency response and maintenance. For example, Jemena Gas Networks notes that its gas distribution "facilities assets also include valves to isolate certain segments of a network". (Jemena Gas Networks (NSW) Ltd Facilities Asset Class Strategy, June 2024).
In terms of maintenance, distributors typically run periodic operational checks / exercising programs (i.e., checking the valve can be operated) and carry out remedial repair where a valve is found inoperable. Consistent with this, US federal pipeline safety rules require that each valve "necessary for the safe operation of a distribution system" be "checked and serviced" at intervals not exceeding 15 months (at least once each calendar year), with "prompt remedial action" if a valve is inoperable. https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D/part-192/subpart-M/section-192.747
As to life when new, Jemena states the "industry accepted design life" for medium and low pressure network components is 50 years, and that "effective integrity management can **extend the operating life well beyond the design life**." Jemena Gas Networks (NSW) Ltd Networks Asset Class Strategy, October 2023.

design life because it reduces future leak repairs, emergency response and compliance costs. However, where decommissioning of a network area is expected before a replacement's life would be fully utilised, the economics can shift: rather than incur large replacement capex (excavation, traffic management, reinstatement, customer interruptions and commissioning), it can be lower NPV to adopt an Opex-heavy strategy of intensified inspection and leak survey, targeted repairs (for example using clamps/sleeves or short cut-outs), and more frequent monitoring to maintain safety and reliability until closure, while avoiding investment in long-lived replacement assets that would be stranded when supply is withdrawn.

4.4 Key conclusions

57. The key conclusions from this section are

a. Ofgem analysis and precedent suggests that network scale (not usage) is the driver of Opex;

b. Engineering/economic logic suggests that usage will play some sort of role as a driver of Opex to the extent that Opex is repairing "wear and tear" caused by usage.

c. However, there is no obvious way in which fewer customers/throughput meaningfully reduces "wear and tear" on gas distribution assets such that they required less maintenance expenditure;

d. Even if there was a link between Opex and usage related "wear and tear", reduced usage would only begin affecting Opex with a material time lag. This must be the case unless Opex this year is responsive to this year's usage related "wear and tear" as opposed to accumulated wear and tear of many years.

e. There are actually good reasons to believe that the efficient response to declining usage, and future network decommissioning, is to substitute Opex for capex (increasing Opex rather than reducing it).

5 Critique of draft decision statistical and economic reasoning

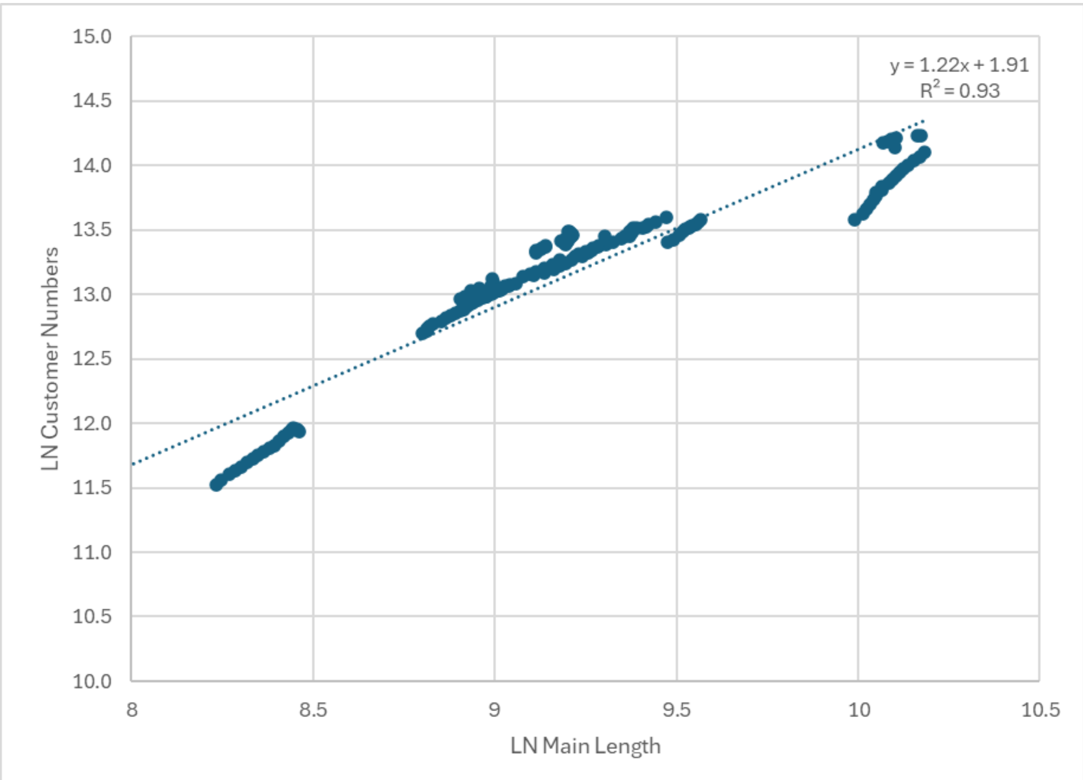
58. We do not consider there is a reliable statistical basis for using regression models estimated over a period when line length, customer numbers and throughput moved together to infer separate "weights" on each variable as cost drivers. In that historical data, the variables are highly collinear (see section 5.1 below), so the model cannot cleanly disentangle their individual effects. Once their future paths decouple, any attempt to apply those estimated coefficients to forecast costs becomes inherently unstable and should not be treated as robust evidence on the relative importance of each driver.

59. We explain this using an illustrative model in section 5.2 and, in doing so, explain why the AER's approach of excluding regressions with negative coefficients ("monotonicity violations") actually makes the problem worse. In section 5.3 we discuss why multicollinearity also affects the interpretation of the time trend in the regressions. In section 5.4 we attempt to understand other statistical/economic claims in the draft decision.

5.1 There is severe multicollinearity between customer numbers and other regressors

60. There is severe multicollinearity between mains length, customer numbers and throughput. For example, regressing the log of customer numbers on the log of mains length results in a 0.93 R-squared. That is, 93% of the variation in customer numbers is explained by variation in mains length (and vice versa). The correlation coefficient between these two variables is 0.96.

Figure 5-1: Log of customer numbers versus main length



61. Variance inflation factors (VIFs) are commonly used to diagnose multicollinearity. As a widely used rule of thumb in applied econometrics, VIF values above 10 — corresponding to an auxiliary regression R^2above 0.9 — are regarded as indicating serious multicollinearity (see, for example, Gujarati and Porter, *Basic Econometrics*; Kutner et al., *Applied Linear Statistical Models*)."

62. For any regressor, the VIF measures how much the variance of its estimated coefficient is inflated due to correlation with the other regressors in the model. Formally, the VIF for a variable is defined as VIF = $1/(1 – R^2)$, where R^2 is obtained from an auxiliary regression of that variable on all other regressors. A high VIF indicates that most of the variation in the variable of interest can already be explained by the remaining regressors, leaving little independent variation with which to identify its coefficient.

63. In the simplest case where the regression includes only main length and customer numbers, the VIF for customer numbers is 13.3. This corresponds to an R^2 of approximately 0.925 (13.3=1/0.075) from regressing customer numbers on main length alone, indicating a high degree of correlation between the two variables. As already noted, a VIF of above 10 is a common threshold for the existence of strong multicollinearity.

64. However, the VIF of 13.3 is not the relevant diagnostic for the model specifications used in this case. The relevant VIF on customer numbers is much higher because the relevant model specifications include main length, firm fixed effects and a time trend. Consequently, the relevant multicollinearity question is no longer the simple correlation between customer numbers and any single regressor, but whether customer numbers retain sufficient independent variation to be separately identified once these additional controls (firm fixed effects and time trend) are included.

65. This can be assessed by examining the VIF for customer numbers in the full specification. When main length and firm fixed effects are included, the VIF for customer numbers rises to 146.5, implying that more than 99 per cent of the variation in customer numbers is already explained by those controls. When a time trend is added, the VIF increases further to 342.7, indicating that almost all remaining variation in customer numbers is absorbed by main length, firm effects and trend.

66. Consistent with this result, the partial regression (added-variable) plot for customer numbers exhibits an extremely low partial R^2 (see Figure 5-2 below). This indicates that, conditional on main length, firm fixed effects and the time trend, customer numbers explains only 2.6% of the remaining variation in opex.

Figure 5-2: Partial regression (added-variable) plot for customer numbers (R^2 =2.6%)

67. Importantly, this explanatory power is identified from a very limited amount of independent variation in customer numbers, as reflected in the extremely high VIFs. As a result, the coefficient on customer numbers is weakly identified and highly sensitive to randomness in the data and specification choices.

5.2 Excluding models with monotonicity violations makes the multicollinearity problem worse

68. The key statistical failure in the draft decision reasoning is contained in these the second and third paragraphs extracted below. The first paragraph is a correct description of the multicollinearity problem EVO identified. However, the next two paragraphs are highly problematic from a statistical and economic perspective.

> *The econometric modelling results statistically establish a historical relationship between Opex and the set of cost drivers specified. However, the presence of multi-collinearity in some of the cost drivers may not allow us to reliably estimate individual parameters. Where the pattern of multicollinearity remains the same, this is not a concern for forecasting Opex. However, this is no longer the case for Evoenergy's forecast period, as the increasing rate of electrification has affected the different cost drivers to a varying extent.*
>
> *As a result, we* ***consider that only models with reliably estimated individual parameters (that is, where the estimated coefficient is of the expected sign) can be used to forecast Opex. This ensures that the change in each individual driver is incorporated correctly into the overall impact. On this basis, we have excluded models with monotonicity violations.*** *[49]*
>
> ***We disagree with Evoenergy's view, however, that the econometric models only capture the relationship between Opex and outputs when outputs are increasing. The Opex model is a short-run variable cost function model, which estimates Opex changes with output changes, quasi-fixed capital input, and other relevant operating environment factors. The Opex***

relationship with individual outputs in the short run is not considered asymmetric. For the given capital input, the variable cost (that is, Opex) is assumed to change in proportion to an output, regardless of whether the Opex is increasing or decreasing.

69. In this passage the AER is saying:

   a. That there is multicollinearity between "output" variables that means that individual parameters are unreliably estimated;

   b. The solution to that is to exclude all models where individual parameters are negative on the basis that negative parameters are unreliable due to an economic assumption that all outputs are positively related to costs;

   c. Then simply give full weight to the parameters estimated in the remaining (not excluded models) on the basis that multicollinearity is, for some unstated reason, not affecting the individual parameters in those models.

70. Not only is the draft decision logic wrong, the proposed solution demonstrably makes the problem worse.

71. This can best be illustrated by application of a simple model in which:

   a. The **true** relationship between Opex and cost drivers is:

      Opex = $5 \times MVEA^{0.5} + \varepsilon_{OPEX}$

   b. There is multicollinearity between MVEA and customer numbers (CN) such that:

      CN = MVEA + ε_{CN}

   c. The error term for Opex (ε_{OPEX}) is uncorrelated with the error term for CN (ε_{CN}) and has a standard deviation that is 3 times higher.

   d. MVEA starts at $100m is growing at a steady rate of 1% per annum and, given assumption b., so are customer numbers (with variability due to ε_{CN} as set out in assumption c).

   e. There are 200 observations available as inputs to the regression.

   f. We perform 5,000 different regressions – each one based on the same set up but with different randomly generated error terms. However, the regression estimated has the **incorrect** functional form:

      Opex = $5 \times MVEA^{\alpha} \times CN^{\beta}$

72. When we run this regression 5,000 times the average coefficient on:

   a. MVEA is 0.5 (i.e., is very close to the correct estimate).

   b. CN is 0.0 (i.e., very close to the correct estimate).

73. However, around 3,700 of these 5,000 regressions have a negative coefficient. This is because the multicollinearity between MVEA and CN means that the regression can fit the data by putting positive weight on one variable and negative weight on the other. Exactly which variable it chooses for the positive weight is driven in part by the fact that the true relationship between MVEA and Opex but also simply by randomness in the error terms. In our set up:

   a. the coefficient on CN is negative 50% of the time (because its true value is zero and its coefficient randomly varies around zero) and accounts for 69% of the negative coefficients; and

b. the coefficient on MVEA is negative 23% of the time (because its true value is 0.5 so random variation causes it to the negative less frequently than for CN) and accounts for 31% of the negative coefficients.

74. It is expected that CN receives a negative weight more often because its true relationship with Opex is zero and MVEA's true relationship is positive. But, even though MVEA has a true positive relationship it still accounts for 31% of the regressions that have negative coefficients.

75. Critically, if we exclude all of the regressions with negative coefficients, as the AER has done, then the average coefficient on:

a. MVEA is 0.256 (i.e., about half the correct estimate of 0.50).

b. CN is 0.246(i.e., well above the correct estimate of 0.00).

76. These results are summarised in Table 5-1 below.

Table 5-1: Summary of results of illustrative regression model

Regressor	Correct value (by construction)	Average across all regressions	Average across regressions without -ve coefficients
MVEA	0.50	0.50	0.26
CN	0.00	0.00	0.24
Sum of both coefficients		0.50	0.50
Number of regressions		5,000	1,294
% of regressions where MVEA had a negative coefficient		24%	
% of regressions where CN had a negative coefficient		50%	

77. Clearly, excluding regressions with negative coefficients has made the results less, not more, accurate. It results if the weight on the spurious regressor (in our set up, this is customer numbers) being over estimated and the weight on true cost drive driver (in our set up, this is MVEA) being underestimated by the same amount.

78. Note that in both the full sample and the sample excluding regressions with negative coefficients, the sum of the coefficients is 0.50 – which is the correct coefficient on MVEA. However, only in the full sample are the coefficients accurate on average. In the smaller sample of regressions after exclusions, the average coefficient on MVEA is half what it should be and the average coefficient on CN is over-estimated by exactly the underestimate on MVEA.

79. The reason for this is simple.

a. With multicollinearity there is randomness about which regressor will get what weight.

b. If there are spurious regressors (regressors that have little or no relationship with Opex in reality) then, in the presence of strong multicollinearity the regression can still fit the data accurately so long as the sum of the coefficients equals the true coefficient on the non-spurious regressor.

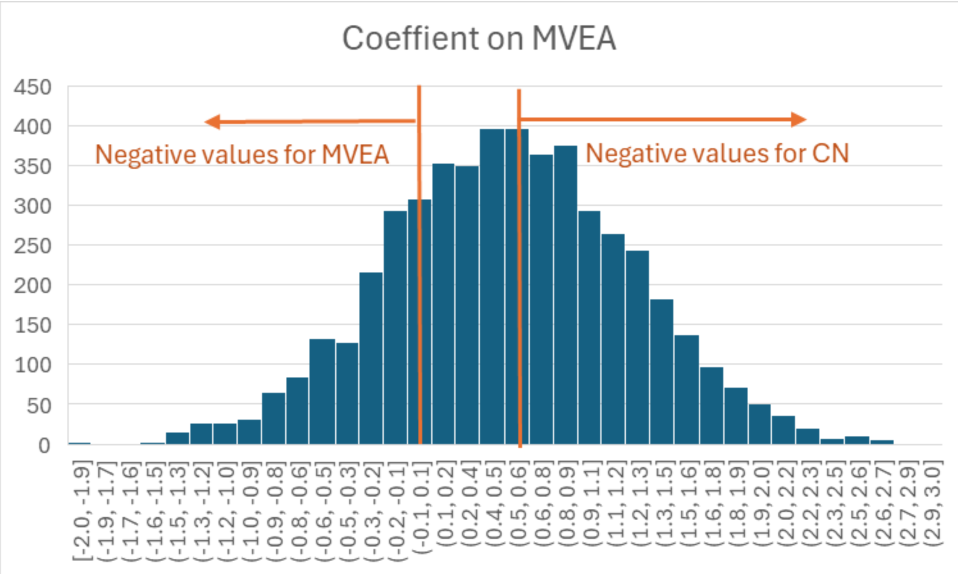
c. Often this leads to one regressor being negative and the other positive. This will most commonly (but not always) involve the spurious regressor being negative;

d. It follows that excluding regressions with negative coefficients will tend to bias the residual sample of regressions towards ones that have a positive coefficient for the spurious regressors. Given b, this means that the sample will be biased to regressions that underestimate the coefficient on the true cost driver by the same amount.

80. Put simply, a truly spurious regressor can be expected to have negative weight in roughly 50% of all regressions. Excluding those regressions leaves only regressions that have over-estimated its true weight.

81. This phenomenon can be seen visually by plotting a histogram of the full set of regression coefficients for each variable and then visually excluding all regressions where that coefficient is negative (easily seen on the histogram) or where the other coefficient is negative. Where the other regressor is negative can be inferred from the histogram by noting that the sum of the coefficients is always 0.50.[14] Consequently, whenever one coefficient is above 0.50 the other must be below 0.50.

Figure 5-3: Histogram of coefficient on MVEA

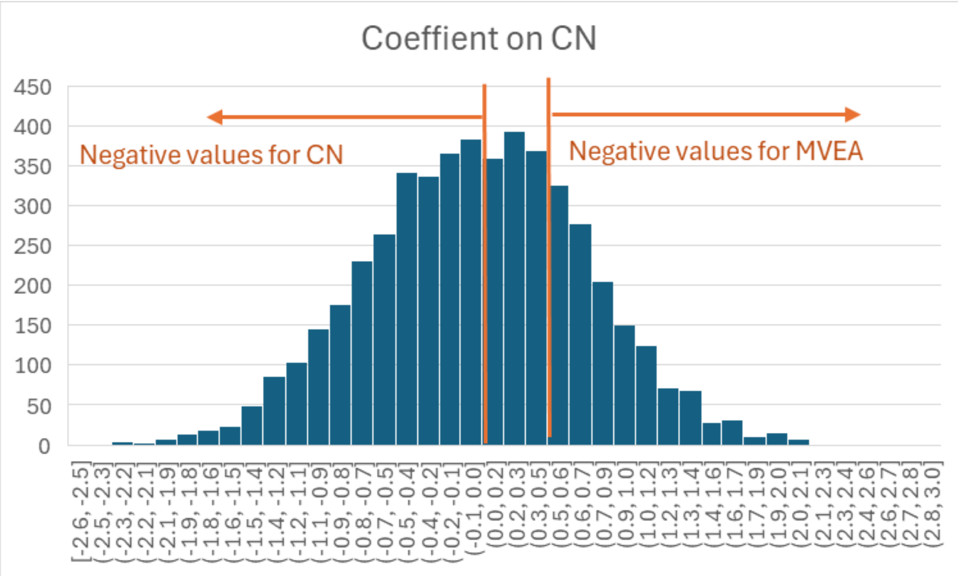


82. Clearly, the average coefficient on MVEA is the correct "0.50" estimate. However, the average regressor on MVEA when regressions with negative coefficients are excluded is the average of the values between the two orange lines (bounded by 0.0 and 0.50). At 0.26 this is slightly above the middle of this range due to density of the histogram being higher close to the top end of the range.

83. The same logic can be followed looking at the histogram of the coefficients on CN.

14 Specifically, the sum of the coefficients falls between 0.49 and 0.51 in all of the 5,000 regressions.

Figure 5-4: Histogram of coefficient on CN



84. Clearly, the average coefficient on CN is the correct 0.0 estimate. However, the average regressor on CN when regressions with negative coefficients are excluded is the average of the values between the orange lines (bounded by 0.0 and 0.50). At 0.24 it is slightly below the middle of this range due to density of the histogram being higher close to the bottom end of the range.

5.3 Time trend parameters from the regressions are also affected by multicollinearity

85. It is also the case that the time trend in the regressions are unreliable due to multicollinearity. Put simply, with a positive trend in the "output" variables and scale economies (falling Opex per unit of "output") the regression can fit very similar data by:

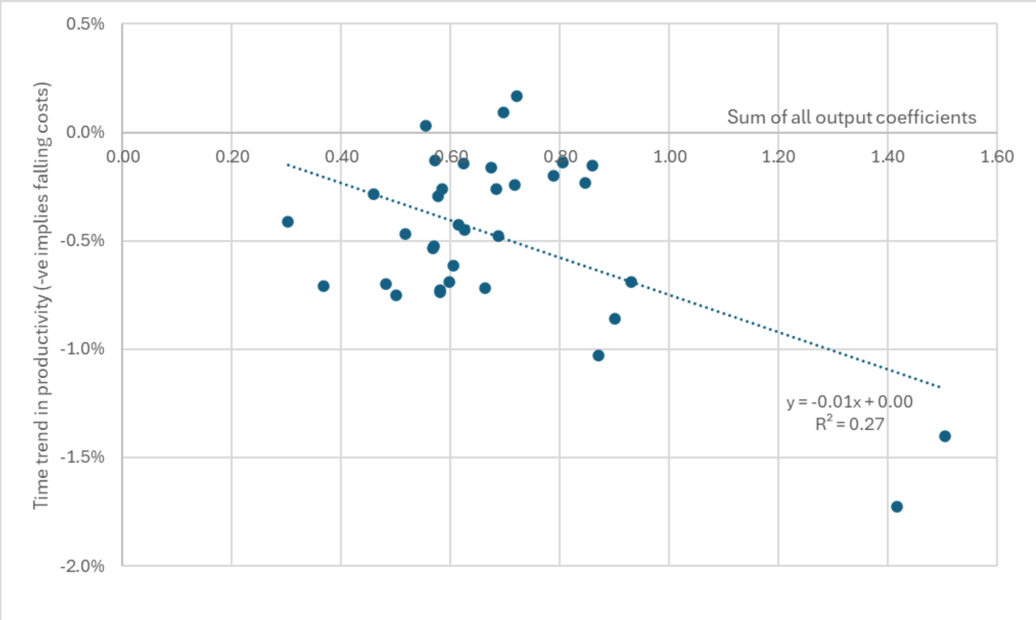
a. Having a strong positive relationship between "outputs" and Opex coupled with a strongly negative time trend; or

b. Having a weekly positive relationship between "outputs" and Opex coupled with a weak negative time trend (or even a positive time trend).

86. That is, the data shows growing outputs and falling Opex per output but it has trouble determining whether this is driven by strong economies of scale (low sum of output coefficients) or strong productivity time trends.

87. That this is the case can be seen clearly in Figure 5-5 which plots each regression's time trend against its sum of output coefficients. It can be seen that that there is strong negative relationship between these variables. The stronger the economies of scale (the smaller the sum of "output" coefficients) the smaller the time trend (and *vice versa*).

Figure 5-5: Time trend more negative the smaller the economies of scale



88. Therefore, for EVO the choice of model matters in a very particular way. In the historical sample, the models can “explain” falling Opex per unit of output either by (i) attributing a large part of cost growth to outputs (i.e. a high sum of output coefficients, implying weak economies of scale or even diseconomies) and then offsetting that with a strongly negative time trend, or by (ii) attributing less to outputs (stronger economies of scale) and relying less on the time trend.

89. In EVO’s forecast period, however, network scale is effectively flat (there is no material reduction in mains length until coordinated decommissioning occurs), while customer numbers and throughput are expected to fall. This means that, under models with high output coefficients and a strongly negative time trend, EVO is “hit twice”: forecast Opex is pushed down by (a) the large negative time trend and (b) the modelled effect of declining outputs, even though the underlying asset footprint that drives much of Opex is unchanged. Put differently, those models effectively treat the historical decline in Opex per unit of output as evidence of strong productivity improvement, and then mechanically apply that assumed productivity improvement to EVO in a period where there is no offsetting growth in network scale and no physical network retirement. The result is an artificially low Opex allowance, driven by parameter combinations that are not reliably identified and that are particularly punitive when applied to a business whose scale is static but whose usage metrics are falling.

90. In our view, the AER should follow the NZCC lead on this and simply adopt a zero time trend.[15]

> *3.53. We have applied an Opex partial productivity factor (PPF) of 0%. This decision draws on recent trends in measured productivity, consideration of the prospect of Opex-capex substitution and the wider context of a declining gas market.*

5.4 Other paragraphs in the draft decision

91. The draft decision also states:

[15] Gas DPP4 reset 2026, Default price-quality paths for gas pipeline, businesses from 1 October 2026, Draft decision - reasons paper, 27 November 2025, para 3.53.

We disagree with Evoenergy's view, however, that the econometric models only capture the relationship between Opex and outputs when outputs are increasing. The Opex model is a short-run variable cost function model, which estimates Opex changes with output changes, quasi-fixed capital input, and other relevant operating environment factors. The Opex relationship with individual outputs in the short run is not considered asymmetric. For the given capital input, the variable cost (that is, Opex) is assumed to change in proportion to an output, regardless of whether the Opex is increasing or decreasing.

92. The draft decision also states:

We disagree with Evoenergy's view, however, that the econometric models only capture the relationship between Opex and outputs when outputs are increasing. The Opex model is a short-run variable cost function model, which estimates Opex changes with output changes, quasi-fixed capital input, and other relevant operating environment factors. The Opex relationship with individual outputs in the short run is not considered asymmetric. For the given capital input, the variable cost (that is, Opex) is assumed to change in proportion to an output, regardless of whether the Opex is increasing or decreasing.

93. We are not persuaded that this paragraph responds to Evoenergy's concern. At most, it appears to assert that the estimated cost function is *specified* in a way that treats output changes symmetrically (i.e., the same linear relationship between Opex and each output is applied irrespective of whether that output is rising or falling—because no mechanism for asymmetry has been incorporated into the model (for example, via ratchet variables or threshold effects or separate regimes for expansion and contraction)). Moreover, the fact that customer numbers, throughput and mains length have a colinear increasing trend means that such mechanisms would make no real difference until there is a decoupling between these parameters. Put differently, the model may be *estimated as if* Opex adjusts proportionately and symmetrically to changes in customer numbers and throughput, but that does not mean that the real world follows past modelling assumptions.

94. The statement that "the Opex relationship with individual outputs in the short run is not considered asymmetric" is not an inference that follows from any engineering or statistical evidence. As already explained, the historical data cannot be used to test this due to all parameters having a colinear increasing trend. There is no engineering justification provided by the AER either. This statement is purely an assertion without any basis.

95. The draft decision also states (emphasis added):

In considering the role of the econometric modelling results, we noted that all the econometric studies include the regulatory asset base (RAB) as a proxy for the fixed capital input. We have considered the role of forecast RAB values in forecasting output and productivity growth in the context of accelerated depreciation. Where there is any accelerated depreciation the associated decline in RAB values would not reflect a decline in the fixed capital input. ***We note that the models estimate a positive relationship between RAB and Opex, but an increase in fixed capital would be expected to reduce Opex, all else equal. This suggests that the RAB variable may be capturing some of the output or network effect. For forecasting Opex, we have assumed no Opex–capital substitution by assuming the RAB is held constant.*** *(And thus, forecast Opex is unimpacted by accelerated depreciation or any other changes in RAB.) The assumed zero growth is between increasing mains length and declining energy throughput, maximum demand and customer numbers. Consequently, zero growth is within the range (and most likely on the lower end) of the missing output dimension.*

96. In this passage the AER has identified that RAB is a problematic variable to have ever included in the regression analysis. We agree with this and think that it is worthwhile expanding on the reasoning

by considering the difference between RAB and MEAV. If a network was built "overnight" then its RAB and MEAV would be the same. MEAV equals the cost of replacing the existing network and, if the network had just been built its RAB would equal MEAV. However, RAB departs from MEAV because the older the average age of the assets:

a. The greater the role of depreciation in reducing RAB below MEAV; and

b. The original expense of installing each asset will be different due to different unit costs when installed vs now (recalling that Ofgem uses differences in MEAV across networks so changes in unit costs over time do not materially change these relativities).

97. Consequently, a **higher** RAB could mean:

a. More recently installed (newer) assets and, therefore, **lower** Opex (as Opex increases with age); and

b. More assets installed and, therefore, **higher** Opex (as Opex increases with network scale).

98. The fact that regressions tend to find higher RAB is associated with higher Opex is consistent with the second factor tending to outweigh the first. Either way, accelerated depreciation would, obviously, have no impact on Opex and the AER is correct to not allow this to infect its forecasts.

99. Finally, the draft decision's conclusion is as follows:

> *Consequently, we are satisfied that our standard approach remains a reasonable basis for forecasting output growth and is more robust than assigning output weights based on judgement. We consider it to be the best approach available in the circumstances.*

100. We have already explained that there was flawed statistical and economic reasoning that proceeded this conclusion and, therefore, the "consequently" does not follow. In fact, some real world "engineering judgment" is the only reliable basis for the AER to proceed. What the AER describes as its "*standard approach" "for forecasting output growth*" is demonstrably not fit for purpose in the situation EVO finds itself.

6 EVO's problem requires an engineering answer that statistics cannot supply (with the available data)

101. If, as we did in section 5.1, the AER had 5,000 different datasets drawn from the true population data then the solution would be simple. Namely, just take the average coefficients from each regression. That is, give every regression the same weight irrespective of whether some coefficients are negative. With 5,000 different datasets, the average regression parameters will be accurate and reliable even if any individual regression is not.

102. However, the AER only has seven regressions all of which share more or less the same data. That is, the AER really has one regression with some minor variations (some with additional years of data and some with additional regressors)

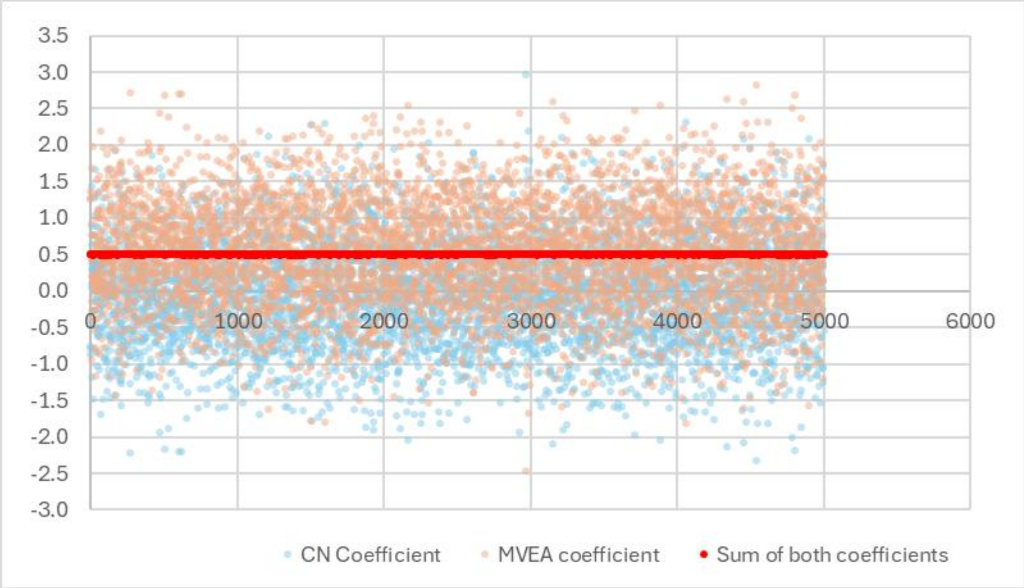
103. The fact that these minor differences, using mostly the same data, result in such large swings in coefficients (as per AER draft decision Table 3.1 reproduced at Table 3-2 above) is precisely because of the serious multicollinearity problem in this dataset. Absent multicollinearity, minor changes in regression data (e.g., adding a few years) or structure (e.g., including RAB or not) should have very small impacts on the coefficients.

104. In this situation, the AER can draw no comfort from averaging across a small number of (not independently generated) regressions. This is true even if the AER were to correct the error in the draft decision and average across all regressions (i.e., not exclude the two regressions with negative coefficients). Of course, none of this would be a problem if the multicollinearity within the historical dataset was repeated for EVO in the forecast period.

105. That is, if customer numbers, throughput and mains length were all continuing to move together then the AER could reliably take the average forecast implied by each regression and apply that to EVO.

106. This is because, as can be seen in Table 5-1, in the presence of multicollinearity the sum of all parameters remains accurate as a predictor of future Opex provided all regressors move together. This can be emphasised visually by plotting each coefficient from each of the 5,000 regressions together alongside the sum of the coefficients.

Figure 6-1: Sum of all coefficients across the 5,000 regressions



107. Clearly, the sum of the coefficients is almost perfectly stable. But the individual coefficients are wildly unstable. That is the effect of multicollinearity in a regression. The individual coefficients are unreliable but the sum of the coefficients are reliable as a predictor of what happens when the regressors move together.

108. The AER really only has the result of one regression (with minor variations in structure and data) to rely on. To try and use this to generate a reliable estimate of the true cost drivers for EVO is the equivalent of picking a single pair of blue and orange dots from the 5,000 pairs shown in Figure 6-1 and hoping that this single selection accurately reflects the true weight on the individual parameters.

109. Of course, if the multicollinearity from the past continued into the future then the individual coefficients can be used to predict Opex because, in effect, the forecast is just adding the coefficients together. It doesn't matter if the true cost driver is MVEA or customer numbers. So long as they move together in the forecast period the regression results will reliably forecast future Opex because it will be effectively using the sum of the coefficients – which is reliable.

110. However, this is not the case for EVO and, consequently, a different approach is required. Ultimately, the solution to this problem is not one that can be solved via statistical means. The AER cannot find the answer to which regressor truly drives Opex in the available data because of the multicollinearity in the historical data.

111. The AER needs to come to a view on this based on an engineering assessment. Specifically, the AER needs an engineering answer to the question:

Will falling customer numbers and/or throughput result in any material Opex savings prior to the decommissioning of segments of the network? If so, how much?

112. We are not engineers so we cannot provide a direct answer to this question. However, as a matter of common sense, it appears to us that a sensible presumption is that the scale, age and complexity of the network being operated and maintained, along with the and safety and reliability regulatory environment, will determine operating costs.

113. To the extent that customer numbers and throughput start falling but the scale, age and complexity of the network do not change (nor the regulatory environment) it is hard to see why falling customer numbers and throughput would lead to material operating cost savings. Indeed, one can imagine a

scenario where operating costs would increase as a gas distributor efficiently seeks to avoid investing in capex solutions (e.g., higher Opex to avoid replacing ageing assets prior to a network area being decommissioned).

114. In section 4 we discussed Ofgem's approach to cost modelling which explicitly uses MVEA as its cost driver preference to customer number, throughput of mains length. This aligns with what we, as economists, would expect to be the case. We also note that:

a. Out of customer numbers, throughput or km mains length, km mains length is the closest corollary for MVEA available to the AER;

b. Both km of mains length and $ value of MVEA are likely to behave similarly for EVO in the forecast period. That is, km mains and $ value of replacement cost of its network are unlikely to fall until regions within the network are decommissioned.

115. That is, Ofgem has had regard to engineering evidence and logic and has determined that the network scale, as proxied by replacement cost, is the driver of Opex – not customer numbers or throughput. We consider that this is important regulatory precedent that the AER can rely on to resolve the (so far unique in Australian gas distribution history) problem created by EVOs forecasts of customer numbers and throughput decoupling from its forecast of network scale.

7 Best use of the AER regression models for EVO

116. In our view, the best use of the AER regression models for EVO is as follows.

a. Absent any engineering evidence that usage gives rise to "wear and tear" that drives contemporaneous maintenance costs, adopt the Ofgem precedent that Opex is driven by the current scale, age and complexity of the network;

b. Choose mains length as the best available proxy for network scale (noting that network age and complexity are already captured in EVO's base year Opex)

c. Given that multicollinearity makes individual coefficients unreliable, the AER should sum the coefficients for all three parameters (mains length, customer numbers and throughput) in each regression and treat that summed value as the coefficient for mains length;

d. The AER should not exclude any regression models on the basis of "monotonicity violations" for the reasons set out in section 5.1;

e. The AER should continue to give zero weight to variation in RAB as a cost driver; and

f. When it comes to the regression time trend the AER could:

   i. Preferred option: ignore the time trend components of the models on the same basis as RAB (and for the reasons explained in section 5.3 and consistent with NZCC precedent); or

   ii. Aggressive option: apply the model time trend ignoring the multicollinearity that causes the regressions to confuse scale economies with negative time trends.

117. Following this approach and an assumed 0.05% pa growth in mains length then output would grow at 0.05% per annum and productivity would be static at zero.

118. If, instead, the less preferred approach of adopting the regression time trends was implemented then the resulting annual productivity estimates would be as set out in Table 7-1 below. These are almost fully reflective of the annual time trend (with only a small further impact from the increase in scale due to 0.05% growth in assumed scale).

Table 7-1: productivity estimates based on the less preferred option of adopting regression time trends

	Jun 2027	Jun 2028	Jun 2029	Jun 2030	Jun 2031
AA (2016)	0.45%	0.45%	0.45%	0.45%	0.45%
AA (2016)	0.47%	0.47%	0.47%	0.47%	0.47%
EI (2019)	0.67%	0.67%	0.67%	0.67%	0.67%
AA (2022)	0.58%	0.58%	0.58%	0.58%	0.58%
CEG (2024)	0.99%	0.99%	0.99%	0.99%	0.99%
EI (2015)	0.73%	0.73%	0.73%	0.73%	0.73%
EI (2016)	0.16%	0.16%	0.16%	0.16%	0.16%