Victorian Energy Future Network
www.vefn.au
Submission to the Australian Energy Market Commission

Gas Networks in Transition: Directions Paper (GRC0082)

April 2026

The Victorian Energy Future Network (VEFN) welcomes the opportunity to make this submission on the Commission's Directions Paper of 19 March 2026. We commend the Commission for the breadth and care of the proposed package, and for its clarity in acknowledging the limits of what economic regulation alone can achieve for a network in structural decline.

VEFN is an independent organisation focused on Victoria's energy transition, with particular interests in gas market reform, electricity distribution planning, and consumer protection. We engage via regulatory submissions and parliamentary processes. Our perspective is shaped by Victoria's position as the leading-edge jurisdiction on residential gas transition.

1. The institutional gap and why GRC0082 matters

The Gas Networks in Transition consultation has produced broad agreement on a fundamental point: gas distribution networks across the National Energy Market face declining throughput, and the institutional arrangements that govern them were designed for a different era. The Directions Paper reflects this consensus. So do submissions from gas distributors, electricity retailers, consumer advocates, and state government bodies, even where they differ sharply on what should be done.

VEFN's contribution is to focus on a more specific and, we suggest, more tractable question. Within the broader proposition that the gas distribution sector is changing, there is a particular institutional gap that no party currently has the authority or remit to close: the orderly retirement of gas distribution networks alongside the parallel growth of electricity distribution networks. The decommissioning of gas zones, the timing and geography of customer transitions, the depreciation and write-down trajectories of gas assets, and the augmentation requirements those transitions impose on electricity networks are all interdependent. Yet they are being managed by separate institutions, under separate frameworks, with no formal mechanism for reconciling their assumptions or coordinating their decisions.

This is not a speculative problem. The cross-system load transfer is happening now, measured in detail by electricity distributors and not at all by their gas counterparts. The resulting information asymmetry is producing multi-billion-dollar regulatory uncertainty in the current Victorian electricity distribution determinations. The longer the gap remains unaddressed, the more those costs accrue.

We frame the institutional gap in this way for two reasons.

First, this framing does not depend on any particular view about the pace of the energy transition. Whatever pace is chosen, the planning machinery needs to be capable of executing it. A slower transition makes coordinated retirement more important, not less, because the gas network will bear declining throughput for longer. A faster transition makes it more urgent. The institutional architecture question sits beneath the pace question.

Second, the institutional gap can be partially addressed using powers the AEMC already holds, and partially through reforms that fall beyond those powers. Both matter. Section 4 of this submission addresses rule changes the AEMC can make now. Section 5 addresses framework changes requiring NGL amendments or coordinated government action. Section 6 deals with cost allocation principles, which we treat as inseparable from disclosure-based reforms but which warrant their own framing. There is a real risk that breaking gas distributor denial about decline succeeds rhetorically while leaving open the question of who bears the residual costs of stranded assets.

2. Evidence of the asymmetry

Cross-system load transfer from gas to electricity distribution is happening now, measured in detail by one half of the system and not at all by the other. Victoria's electricity distribution network service providers (DNSPs) are required by their regulatory determinations to forecast the volume, timing, geography, and load shape of customers leaving the gas network for electric appliances. The gas distribution network service providers operating alongside them face no equivalent requirement. This asymmetry is the most concrete evidence of the institutional gap that this Directions Paper (GRC0082) is examining.

2.1 What electricity DNSPs are forecasting

In their regulatory proposals lodged with the Australian Energy Regulator (AER) in January 2025 for the 2026 to 2031 period, the three Victoria Power Networks distributors (CitiPower, Powercor, and United Energy) produced detailed forecasts of how electrification will reshape their networks. Three findings are particularly relevant to GRC0082.

First, the projected magnitude of load transfer is large and explicitly quantified. CitiPower and Powercor's joint analysis estimates that gas electrification in Victoria will add over 2,600 GWh of electricity consumption per year, primarily for space and water heating. Victoria is more dependent on gas than any other Australian jurisdiction, with annual residential consumption around triple that of New South Wales and South Australia and almost seven times Queensland. The distributors use this as the baseline for their local network augmentation plans [Ref: CP/PAL BUS 3.01, January 2025, p. 11].

Figure 1 illustrates the scale of the gas heating load that must ultimately transfer to electricity networks. On peak winter days, residential heating demand (Tariff V) accounts for over half of total Victorian gas consumption; in summer it falls to near zero. The resulting electricity demand will not be a one-for-one translation. Heat pumps typically deliver three to four units of heat per unit of electricity consumed, so the electricity required to deliver the same useful

heat may be of the order of one-fifth to one-quarter of the gas energy consumed. The Victorian Energy Upgrades program, which commenced its insulation rollout for social and community housing in April 2026 and extends to general residential properties from October 2026, will further moderate net demand by improving building thermal performance. But even at favourable efficiency ratios, the peak winter increment is very large in distribution terms. It will arrive on feeders and transformers that were not sized for it.

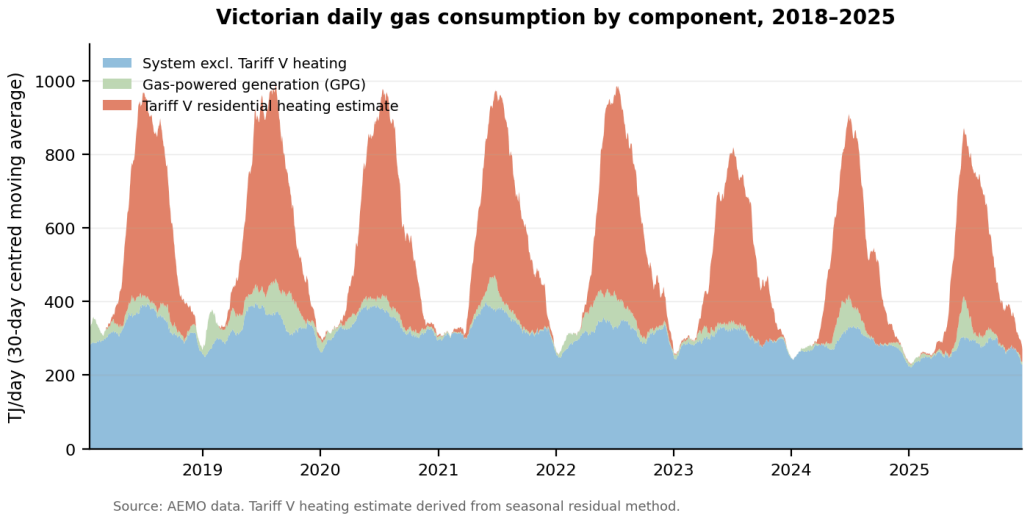

Figure 1: Victorian daily gas consumption by component, 2018 to 2025. Tariff V residential heating demand dominates winter consumption and falls to near zero in summer. Source: AEMO data, VEFN analysis. 30-day centred moving averages. From VEFN submission to AEMO Draft FY27 Strategic Corporate Plan, 17 April 2026.

The planning challenge is sharpened by how unevenly gas consumption is distributed across households. The Frontier Economics residential energy consumption benchmarks, prepared for the AER in 2020 using metered data from 1,380 Victorian households, show a heavily skewed distribution. While the average four-person Victorian household consumes around 26,400 MJ of gas in winter, a visible tail of households consume three to five times that amount (Frontier Economics 2020, Figure 34). The most likely driver is the interaction of inefficient ducted gas heating systems, which field studies have found to operate at whole-of-system efficiencies as low as 30 per cent, with poor building thermal performance. When these households electrify, even with heat pump efficiency ratios of three or four to one, the per-connection electricity demand they create will be substantially larger than any average-based forecast would suggest. These households are not randomly distributed. They cluster by housing age, construction type, and suburb, which means the load transfer will concentrate on specific feeders and transformers rather than spreading evenly across a distribution zone.

Second, the load transfer is changing the seasonal profile of the electricity network. Powercor and United Energy both report, using identical wording in their respective business cases, that "electrification of gas heating will increase winter consumption and peak demand, shifting 10 per cent of our zone substations from summer-peaking to winter-peaking in the next regulatory period. Heating loads are more sustained than cooling loads and will occur when solar production is lowest." [Ref: PAL BUS 3.01, p. 11; UE BUS 3.01, p. 10]. The duplicated

phrasing reflects the shared analytical work of the parent corporate group rather than independent assessments by two distinct networks. The substantive claim is, however, presented in formal regulatory submissions on behalf of both distribution businesses and is supported by the underlying load forecasting in each.

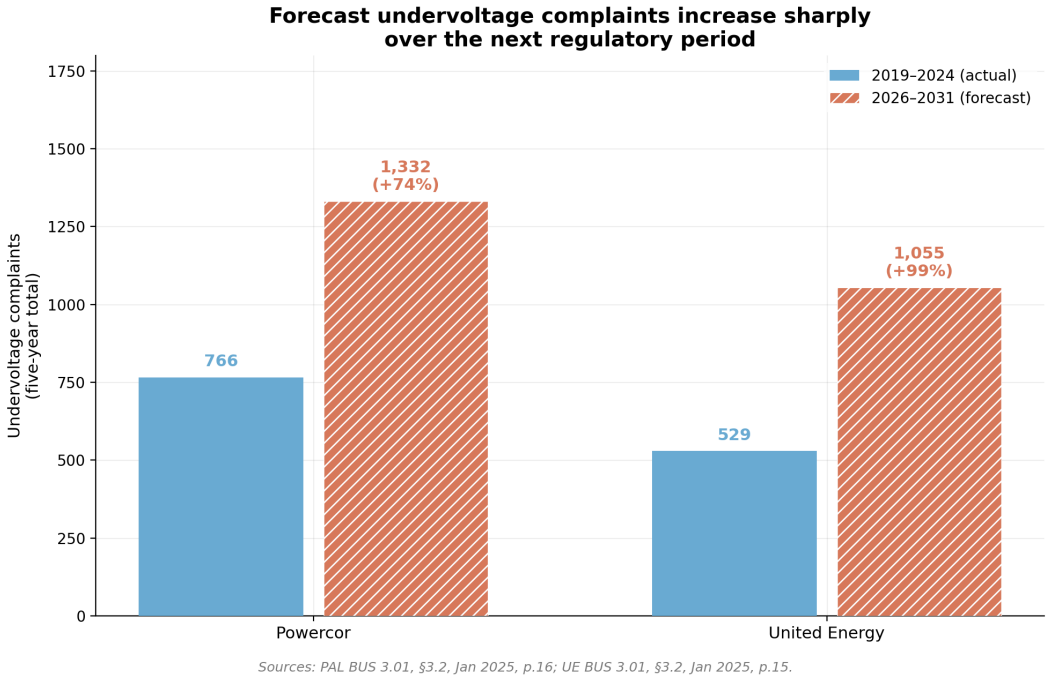

Figure 2: Forecast undervoltage complaints for Powercor and United Energy, comparing 2019 to 2024 actuals with 2026 to 2031 forecasts. Source: Powercor Regulatory Proposal BUS 3.01, §3.2, January 2025, p. 16; United Energy Regulatory Proposal BUS 3.01, §3.2, January 2025, p. 15. VEFN analysis.

Third, the load transfer is appearing in customer experience in measurable ways. Both distributors identify electrification of gas appliances, particularly space heating, as the predominant driver of the increase. Reported complaints are likely only a fraction of those affected, as undervoltage impacts whole localities rather than individual premises.

2.2 What gas distributors are not required to forecast

There is no equivalent body of analysis on the gas side. Victoria's gas distribution businesses (AGN, AusNet, and Multinet) face no regulatory requirement to publish forecasts of which zones or customer cohorts will leave their networks first, on what timetable, or with what implications for the residual customer base. The AER's gas distribution access arrangement reviews assess revenue requirements against the costs of operating the existing network, not against an orderly retirement trajectory. AEMO's Gas Statement of Opportunities provides top-down demand forecasts but does not break these down by distribution zone, customer cohort, or the specific assets that would become surplus to requirements.

The result is a substantial information asymmetry. Electricity DNSPs are publicly forecasting where and when gas customers will leave. Gas distributors face no equivalent obligation. There

is no forum in which the two sets of assumptions are reconciled. Each side is making multi-billion-dollar capital decisions on the basis of partial information about the other.

2.3 The AER and DNSP dispute as evidence of a problem

The current dispute between the AER and the Victorian electricity DNSPs over the 2026 to 2031 capital expenditure proposals illustrates the consequences. The AER's September 2025 draft decision rejected substantial portions of the electrification-related capital expenditure claims: its substitute forecast for Powercor was 26.0 per cent below the proposed forecast, and for CitiPower 27.5 per cent below [AER draft decisions, Attachment 2, September 2025, Table 2.1]. The AER found that the DNSPs had not adequately demonstrated the prudency and efficiency of proposed proactive undervoltage remediation investment.

In the December 2025 revised proposals, both CitiPower and United Energy materially modified their position. Both stated that "our modelling indicates that we will remain compliant with overall voltage levels until FY31 with no proactive investment and the impact of voltage decline is likely to be less than we have forecast" [CP RRP BUS 3.3.01, December 2025, p. 4; UE RRP BUS 3.3.01, December 2025, p. 4]. VEFN takes no position on whether the DNSPs or the AER are correct on the contested capex. But the disagreement illustrates a fundamental tension between network-wide statistical compliance and individual customer experience. The AER and the distributors now agree that overall voltage levels can be maintained. But this average masks localised problems. In rapidly electrifying pockets, households will experience increasing undervoltage even if the broader network remains technically compliant. The gas-to-electric transition happens at the street and feeder level. The planning machinery must be capable of addressing that uneven, zonal reality.

That this disagreement has produced multi-billion-dollar uncertainty in regulatory determinations affecting more than two million Victorian electricity customers, through a process not designed for cross-system coordination, illustrates the institutional gap as plainly as any analytical argument could.

3. Why the existing institutions cannot close the gap

The institutional gap documented in section 2 is not the result of any single body failing to do its job. It is the result of the relevant bodies each being chartered to do other jobs, and the collective machinery not being designed to produce cross-system retirement coordination as an emergent outcome.

3.1 The relevant institutions and what none is asked to do

Four institutions most directly govern Australia's gas distribution networks.

- The AEMC makes the rules, which were drafted on the assumption that gas networks serve a stable or growing customer base. They contain no provision for zonal decline forecasting, cross-system coordination, or stranded asset allocation.
- The AER applies those rules through separate gas and electricity determination processes, on different timetables, with no procedural mechanism requiring reconciliation of their respective assumptions.

- AEMO provides national planning through the GSOO, VGPR, ESOO, and ISP, but without the zonal disaggregation that would expose gas-side assumptions to the same scrutiny electricity-side forecasts already receive, and without formal linkage between its gas and electricity products.
- The ESC, as Victoria's economic regulator, has a more limited role focused on retail price regulation and licensing; its statutory remit does not extend to network planning or asset decommissioning.

Recent Victorian regulatory changes have moved further than any other jurisdiction on geographic data disclosure. Under the ESC's Gas Distribution Code of Practice Version 1, which commenced on 1 October 2024, Victorian gas distributors are required to report abolishments and active meter connections at the postcode level. Some distributors and AEMO also publish consumption data by postcode on a voluntary basis. These are significant departures from national norms. Even so, postcode-level abolishment counts track where the transition has already happened. They do not forecast where the next wave of departures will come from, and they are not linked to corresponding electricity distribution zones or their augmentation plans. A further layer of household-level consumption data already exists within energy retail billing systems. Retailers can identify which individual customers are high gas consumers, but no regulatory obligation requires this information to be shared with distribution network planners on either the gas or electricity side. The commercial incentive runs the other way: a volumetric retailer has no reason to flag high-consumption customers to network planners, nor to help those customers reduce their usage.

What is striking, when these institutions are laid out together, is that none is asked to do the work GRC0082 has identified as missing. None is required to produce zonal forecasts of gas customer departures, to convene gas and electricity distributors to reconcile their assumptions, to develop a framework for orderly retirement of gas distribution zones, or to articulate principles for allocating stranded asset costs. This is not an oversight. The National Gas Law was enacted in 2008, when natural gas was widely regarded as a transition fuel whose use would expand. The institutional architecture reflects the policy assumptions of that era.

3.2 Why collective action under current arrangements does not close the gap

The systemic issue is not coordination failure between bodies that each have partial authority. It is that the authority has not been allocated to any body at all. AEMO can be asked to publish more granular gas planning information but cannot require gas distributors to provide it without rule changes only the AEMC can make. The AEMC can change rules but cannot itself produce planning analysis. The AER can scrutinise what gas distributors submit but cannot require them to submit what the rules do not ask for. State governments can act within their own jurisdictions but cannot create national frameworks.

There is also a quieter institutional dynamic at work. Where a regulatory framework does not require disclosure, regulated businesses generally do not volunteer it, particularly where the disclosed information would weaken their position in revenue determinations. There is a further, financial reason. Once a gas distributor formally acknowledges structural demand decline, debt markets are likely to reprice the risk of lending to a network with a shrinking

revenue base. The absence of zonal decommissioning forecasts on the gas side is therefore not just a gap in regulatory requirements. It is a predictable consequence of the asymmetric incentives facing gas distributors. The institutional gap and the information gap reinforce each other.

The forecasting record illustrates the consequence. AEMO's GSOO has consistently overforecast residential and small commercial gas demand, with each year's forecast revised downward as actual demand comes in below projection. Environment Victoria's submissions have documented this pattern in detail.

Figure 3, reproduced with permission from Environment Victoria, illustrates this pattern for the Victorian Gas Planning Report. Each successive annual edition projects a slower decline than the actual consumption trajectory subsequently reveals.

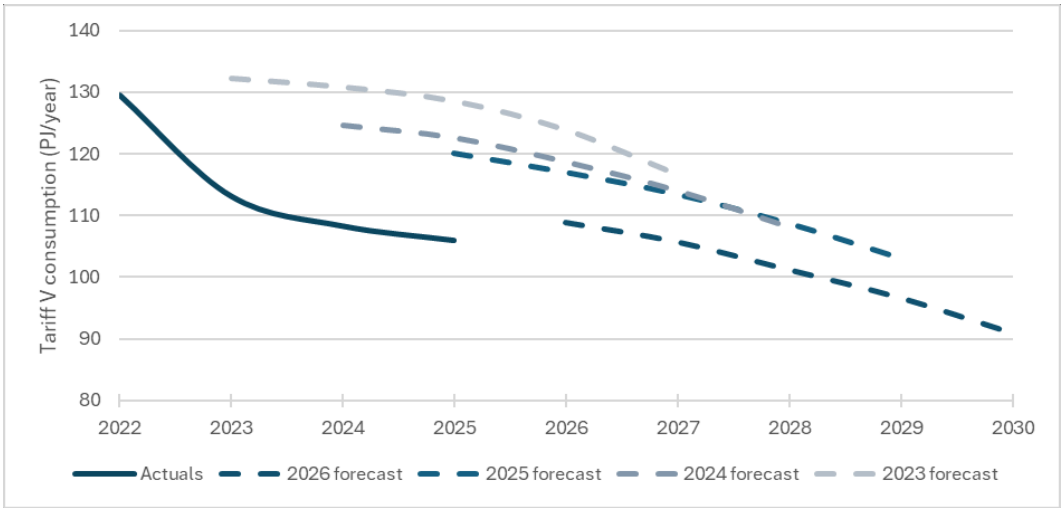

Figure 3: Tariff V consumption forecasts versus actuals from AEMO's 2023 to 2026 Victorian Gas Planning Reports, showing systemic overestimation of forecast gas consumption. Reproduced with permission from Environment Victoria, submission to GRC0082, April 2026.

3.3 International recognition that this is a structural problem

The institutional gap identified here is not unique to Australia. Rosenow's recent work on gas grid regulation in net-zero transitions sets out a five-step framework for managing distribution-network decline, premised on the argument that orderly retirement requires regulatory architecture distinct from that designed to govern stable or growing networks. Grubert's work on minimum viable scale similarly identifies coordinated decommissioning planning as a function that must be deliberately constructed. The Climateworks Centre's November 2025 submission makes the same point in an Australian context. The ACT, through Evoenergy and the ACT government, has begun to develop zonal decommissioning analysis, although at substantially smaller scale than the eastern states.

We do not propose that any of these frameworks be adopted wholesale. The relevant point for GRC0082 is that the institutional gap is internationally recognised, and the broad conclusions of the analytical work agree that closing it requires new institutional architecture rather than better operation of existing institutions.

4. Responses within the Commission's existing powers

4.0 Introduction

The Directions Paper sets out a coherent policy direction for amending the National Gas Rules in response to the transition unfolding in gas distribution networks. VEFN broadly supports the proposed direction and the analysis underpinning it. This section sets out our position on each proposed amendment, together with the Victorian-specific applications and enhancements we consider necessary.

Our comments are pitched at the policy level. The Directions Paper presents policy direction rather than draft rule text, and we reserve detailed drafting comments for the Draft Determination consultation scheduled for 27 August 2026.

Victoria meets the threshold for jurisdiction-specific treatment. Energy Networks Australia proposes that jurisdiction-specific treatment should be reserved for jurisdictions with a distinct obligation or policy direction (ENA submission to GRC0082, p8). VEFN accepts this framing. Victorian policy plainly clears the threshold. The Gas Substitution Roadmap, the ESC's Code of Practice for electrification, the legislated restrictions on new gas connections (with further restrictions commencing 1 January 2027), and the State Electricity Commission's electrification mandate together represent the most extensive policy direction of any Australian jurisdiction on gas network transition.

4.1 Endorsement of the Commission's problem diagnosis

VEFN endorses the problem diagnosis set out in the Directions Paper and the accompanying CEPA modelling (CEPA, February 2026). The modelling represents a substantial analytical advance and, in our view, settles several framing questions that have been contested in prior consultations.

Three findings in particular are salient to the analysis that follows.

First, the CEPA modelled networks map closely onto the Victorian distribution networks. CEPA Network 1 (RAB per gigajoule of $60, residential and commercial share 85 per cent) and CEPA Network 2 (RAB per gigajoule of $30, residential and commercial share 85 per cent) span the parameter range of Multinet, AGN Victoria, and AusNet (RAB per gigajoule approximately $30 to $44, residential and commercial share approximately 52 to 85 per cent). The CEPA rapid-decline scenario is explicitly informed by jurisdictions with strict electrification targets, including the ACT and Victoria (CEPA report, p10). The modelling is therefore not a general-purpose sensitivity analysis but, in substantial part, a direct analysis of the Victorian trajectory.

Second, the modelling confirms what VEFN and others have previously advanced. Under the rapid-decline scenario, CEPA finds that no affordable amount of accelerated depreciation will achieve long-term price stability. Network 1 reaches the switching point (approximately $2,660 per household) in 2036, with $339 million (68 per cent) of the capital base unrecovered (CEPA report, Figure 2.2). The Directions Paper accepts this, acknowledging that the

regulatory framework cannot fully address the adverse impacts of declining demand under all demand scenarios (Directions Paper, Summary, Point 19).

Third, the CEPA analysis establishes that the challenge confronting Victorian distribution networks is structural, not regulatory. It is a mismatch between the capital recovery model and the demand trajectory. The Commission's own analysis now carries the tipping-point framing VEFN has previously used. It is also consistent with the Victorian DNSP evidence in section 2.

One Victorian-specific enhancement. CEPA's switching-point calculation uses a wholesale gas price assumption of approximately $13 per gigajoule. Victorian wholesale prices have been materially more volatile, with sustained periods above $20 per gigajoule during the winters of 2022 and 2023. Volatility matters because household switching decisions are typically made at high-price moments rather than on long-term averages, and high-price episodes accelerate discretionary electrification. The CEPA results for Network 1 should therefore be read as an upper bound on the timing of the Victorian switching point, not as a central estimate.

4.2 Amendments to capital cost recovery provisions

The Directions Paper proposes three amendments to the capital cost recovery provisions: removal of the demand-growth limb from Rule 89, structured guidance on accelerated depreciation, and a rules-based redundant capital mechanism. VEFN supports each amendment.

Rule 89 demand-growth limb. The CEPA modelling is unambiguous that continued capital expenditure premised on demand growth is inconsistent with the demand trajectory facing Victorian networks. Removing the growth limb aligns Rule 89 with forecast conditions. Some network submissions, including AGIG's, argue that the growth limb should be retained to accommodate localised growth in specific segments. In our view, any such localised growth is better dealt with through the forecast demand provisions proposed elsewhere in the Directions Paper than by retaining the growth limb in its current form.

Accelerated depreciation guidance. VEFN has previously supported the principle of structured accelerated depreciation guidance (VEFN submission to GRC0086, 10 December 2025). We maintain that position. The guidance should be anchored in independent demand scenarios (the AEMO GSOO and, in due course, the DSOO) rather than in network-specific forecasts. The case for conditional access to accelerated depreciation, including the demand-risk and cost allocation framing that underpins it, is developed in section 6.

Rules-based redundant capital mechanism. The existing discretionary approach to redundant capital introduces regulatory uncertainty for all parties. A rules-based mechanism, triggered by defined thresholds of forecast-to-actual demand divergence, would provide a more predictable basis for both networks and consumers. The triggers should be calibrated to rolling three to five year windows.

Victorian-specific application guidance. Given the distinct Victorian policy context, the AER will require guidance on applying these amendments to Victorian networks, addressing at

minimum: 1) the treatment of Gas Substitution Roadmap trajectories in accelerated depreciation assessments; 2) the implications of the 1 January 2027 connection restrictions for forecast demand; and 3) the interaction between the ESC Code of Practice for electrification and the redundant capital triggers. This guidance should be developed in consultation with the ESC and the Victorian Government during the Final Determination phase.

4.3 Amendments to expenditure provisions

The Directions Paper proposes four amendments to the expenditure provisions: introduction of a quantitative options assessment for capex; replacement of "safe and reliable operation" with "safe operation" in defined contexts; replacement of "demand" with "forecast demand" in defined contexts; and deletion of the growth limb from Rule 69. VEFN supports each amendment.

On the quantitative options assessment, we note the Commission's conclusion that the Revenue and Pricing Principles under section 24 of the National Gas Law prevent the Rules from requiring non-pipeline alternatives as part of the capex options assessment. We accept this analysis. The question is where cross-system information required for meaningful gas-electricity coordination should sit. In our view, the 20-year outlook is the appropriate location, as we develop in section 4.4.

One further interaction warrants attention. The proposed "forecast demand" amendment depends on the quality and granularity of available demand forecasts. In Victoria, the current forecasting arrangements are not well adapted to the geographically differentiated electrification trajectory now unfolding. The AEMO Victorian Gas Planning Report provides network-level forecasts but not at the zonal level required for meaningful differentiation of capex between retained and transitioning parts of the network. The Victorian DNSP evidence in section 2 illustrates what zonal-level forecasting looks like when regulators do require it.

4.4 The 20-year outlook

The Commission's proposal to require network service providers to publish a 20-year outlook is the most important single amendment in the Directions Paper. The outlook will be the principal document in which cross-system, demand-trajectory, and strategic decommissioning information is assembled. Its design carries more weight than any other proposed amendment.

VEFN supports the outlook and proposes four enhancements.

4.4.1 Zonal and geographic reporting

The Directions Paper proposes the outlook at the network level. But demand decline and electrification will not be uniform across any Victorian network. Zones adjacent to established electricity distribution capacity will transition more quickly than those where electricity augmentation is constrained. Zones with high commercial gas use will transition on different trajectories from zones dominated by residential use. Older inner-urban zones with higher per-customer network costs face different economics from newer outer-urban zones. Network-level reporting will not resolve these differences. We propose that the outlook be

required at zonal level, with zones defined by reference to either gas distribution sub-networks or the corresponding electricity distribution feeder footprints.

Victoria's ESC has already moved in this direction through its Code of Practice postcode-level reporting requirement. The 20-year outlook should build on this foundation, extending the geographic resolution from backward-looking disconnection counts and voluntary consumption disclosures to mandated, forward-looking demand and transition forecasts cross-referenced with the electricity distribution network.

4.4.2 Intersection with electricity distribution planning

For each zone, the outlook should cross-reference the relevant electricity distribution zone and its forecast augmentation pipeline. This is the information foundation for coordination. Without it, neither networks, the AER, nor governments can assess whether gas decommissioning is being sequenced appropriately with electricity augmentation.

We recognise that this requires gas network service providers to obtain information from electricity distribution businesses in their footprint. The obligation can be discharged either by requiring electricity distributors to provide relevant forecasts to gas distributors on request, or by requiring the AER to publish consolidated zonal forecasts drawing on Distribution Annual Planning Report data and, when available, the Distribution Statement of Opportunities. We have no strong preference between these mechanisms. The substantive requirement is that the outlook for each zone contains a current view of the electricity-side augmentation picture.

4.4.3 Strategic decommissioning segment identification

The Commission has deferred the design of a decommissioning framework to a later process. VEFN accepts that choice. However, the information foundation for strategic decommissioning can and should be established through the 20-year outlook. We propose that the outlook identify candidate segments suitable for early decommissioning, with criteria covering at minimum: demand decline trajectory; electricity augmentation status in the corresponding zone; asset age and replacement cycle; and interaction with adjacent retained segments. Identifying candidate segments does not commit any party to decommissioning them. It creates the information base on which a future decommissioning framework can operate.

4.4.4 Legal form in the National Gas Rules

The Directions Paper leaves open whether the 20-year outlook is established as a rule obligation or as an AER guideline. We consider it should be a hard obligation in the National Gas Rules. The outlook is the single document housing the cross-system information on which all other proposed amendments depend. AER guidelines can be revised on administrative timescales, and institutional incentives in the years ahead will not always favour maintaining demanding disclosure requirements. If the Commission prefers guideline form, we would urge at minimum that the core disclosure requirements, including zonal reporting and electricity intersection, be anchored in the Rules.

4.5 Amendments to reference tariff provisions

The Directions Paper proposes two reference tariff amendments: introduction of a switching-point standalone cost as a tariff constraint, and permission for the AER to have regard to costs and outcomes beyond the access arrangement period. VEFN supports both amendments.

The switching-point constraint gives meaningful content to the consumer protection logic that has been largely absent from reference tariff regulation in declining-demand networks. As tariff trajectories approach the switching point, the households remaining on the network are increasingly those who face the highest barriers to leaving: renters who cannot choose their appliances, elderly residents for whom the disruption of transition is most daunting, and low-income households without the upfront capital for electrification. These are the households for whom the network is not a choice but a necessity. Allowing tariffs to cross the switching point does not just trigger further disconnection in the abstract. It imposes escalating costs on the people with the fewest alternatives.

The within-and-beyond AA amendment is equally important. Five-year access arrangement periods are too short to capture a problem that unfolds over fifteen to twenty years. Permitting the AER to have regard to beyond-AA costs and outcomes aligns the regulatory horizon with the problem horizon.

Victorian-specific application guidance. For the Victorian networks, CEPA's analysis indicates a switching point of approximately 2036 at the $13 per gigajoule wholesale price assumption. As noted in section 4.1, Victorian wholesale price volatility suggests the effective switching point arrives sooner. AER guidance for Victorian networks should: calculate switching-point ceilings using a distribution of Victorian wholesale price outcomes rather than a single point estimate; require tariff trajectories that maintain material headroom below the switching-point ceiling through the 2028 to 2033 access arrangement period; and address the interaction between reference tariffs and the disconnection fee arrangements currently under consideration by the Essential Services Commission.

4.6 Transitional arrangements for Victoria

Question 2 of the Directions Paper asks whether transitional arrangements are required. VEFN considers that they are required for Victoria, and that the specific form they take matters for the effectiveness of the rule change as a whole.

The Victorian access arrangement timeline intersects the rule change timeline in a way that creates avoidable regulatory friction. Victorian networks must lodge reference service proposals by 1 June 2026 and full access arrangement proposals by 1 June 2027. The AEMC Draft Determination is scheduled for 27 August 2026 and the Final Determination for 17 December 2026. Without transitional arrangements, the Victorian AER will be determining reference services under the existing rules while the Commission consults on amendments that directly affect those reference services.

VEFN proposes three transitional arrangements.

First, the rule change should include explicit provision for the AER to re-open or vary elements of the Victorian 2028 access arrangement determination if the Final Rule differs materially from the Directions Paper's policy direction. This provision should be time-bounded.

Second, the Commission should consider a shortened Victorian AA period for the 2028 determination: three years rather than five. This would align the subsequent AA review with a regulatory framework that has had time to bed in. We acknowledge this involves consequential decisions for networks and the AER and raises administrative burden considerations that warrant careful weighing.

Third, guidance should be provided to the Victorian AER to apply the Directions Paper policy direction in its 2028 AA determinations where the policy direction is clearly settled and does not depend on the specific form of the Final Rule.

4.7 Recommendations to governments

The Commission's proposed amendments create the regulatory infrastructure for orderly gas network transition. They do not create the institutional infrastructure. Without a coordination function, the rule changes will apply in a vacuum. The outlook will be prepared, the depreciation will be accelerated, the switching-point ceilings will be calculated. But no institution will have the remit to translate those inputs into sequenced zone-by-zone decisions. How that gap might be closed is the subject of section 5.

5. Institutional reforms beyond the Commission's powers

5.0 Overview

VEFN does not propose that the Commission resolve these matters. They are not the Commission's to resolve. Our purpose is to respond to the Commission's explicit invitation for submissions on the jurisdictional policy signals that will need to develop alongside the rule changes. We suggest that the Commission identify, in its final determination, what those signals would need to contain for the GRC0082 reforms to deliver their intended consumer benefits.

Four elements of beyond-powers reform warrant attention: amendments to the National Gas Law enabling strategic decommissioning as a regulated activity; a coordination function to sequence gas retirement with electricity augmentation at the zonal level; illustrative financial and institutional mechanisms; and Victoria as the test case for whether such reforms can be delivered in practice.

5.1 NGL amendments enabling strategic decommissioning

The current National Gas Law treats decommissioning largely as a residual event: something that may eventually happen to assets that have ceased to be used. The law does not recognise strategic decommissioning: the active retirement of gas network assets in a defined geography

as a planned policy objective rather than as a consequence of asset failure or customer attrition.

The distinction matters. Residual decommissioning arrives with the assets and the customers already gone. Strategic decommissioning is the opposite: an institutional decision made in advance to retire a defined segment so that assets and customers can transition together. The efficiency case is well established in the international literature and illustrated by Evoenergy's work in the ACT, although at substantially smaller scale than any east-coast jurisdiction would require.

Enabling strategic decommissioning requires amendments to the NGL itself. At minimum, these would need to address three elements.

First, the statutory definition of the services a gas distribution network provides would need to expand beyond gas conveyance to include orderly retirement of network segments where that retirement is undertaken in accordance with a jurisdictional policy direction or a coordinated transition plan.

Second, cost recovery arrangements for strategic decommissioning would need to be specified in the law. The current arrangements for redundant capital are designed for unplanned stranding, not planned retirement where costs are incurred deliberately in pursuit of a longer-term public benefit. Section 6 addresses the allocation principles.

Third, consumer protection arrangements for customers affected by strategic decommissioning would need to be articulated: their tariff treatment, their rights to connection continuation or abolishment, and their access to support for electrification. These matters sit beyond the Commission's rule-making remit and appropriately in the law.

The 20-year outlook proposed in section 4.4 provides the information foundation for strategic decommissioning without requiring NGL amendment. Amendments would be required to move from identification of candidate segments to active retirement as a planned policy objective.

5.2 A coordination function for zonal gas and electricity sequencing

The coordination task GRC0082 has identified is currently orphaned across existing institutions. The Commission itself has recognised this. At the GRC0082 public forum on 9 April 2026, it defined an orderly transition as requiring, among other things, that electricity networks have time to undertake the investment needed to absorb gas customers who electrify (AEMC, Summary of Questions and Answers, GNT Public Forum, 9 April 2026, Q9). That definition presupposes exactly the cross-system coordination function that no existing institution is chartered to perform.

Three institutional options warrant consideration.

The first is an expanded AEMO remit. AEMO holds gas and electricity demand data at a level of aggregation no other institution holds, and the inaugural DSOO is evidence that its distribution-level planning capability is maturing. The difficulty is that AEMO's statutory framework is national, while the coordination task is largely jurisdictional. Gas substitution policy is set by state governments. The specific geographies sit inside state regulatory frameworks. AEMO can publish planning information but is less well-placed to serve as the sequencing authority for decisions that remain ultimately jurisdictional.

The second is a dedicated Victorian coordination body with a narrow remit focused on zonal sequencing. This aligns coordination authority with the policy authority driving the transition. The difficulty is institutional cost: new bodies are expensive and slow to establish.

The third is a joint Victorian Government and AER function. The AER has the technical capability and existing accountability relationships with both gas and electricity distributors. The Victorian Government has the policy authority. A joint function could combine these in a way neither body could deliver alone.

In VEFN's view, the joint option is probably the cleanest. The precise institutional form matters less than the clarity of the remit. Whatever body holds the function, it needs: the authority to require zonal-level disclosure from both gas and electricity distributors; the capability to reconcile the resulting forecasts; and the standing to recommend sequencing decisions to the parties responsible for implementing them. A national-level role for AEMO in publishing underlying data and methodologies would complement, not substitute for, the jurisdictional coordination function.

5.3 Illustrative mechanisms

We mention two further mechanisms not as recommendations but as illustrations of the types of interventions that may be required to close the residual stranding problem identified in the CEPA modelling.

Securitisation of the unrecovered Regulated Asset Base has been explored as a means of decoupling capital recovery from continued physical use of declining infrastructure. Ron Ben-David has proposed periodically revaluing the gas RAB to reflect declining throughput, with the resulting reduction structured as a separate, tradable financial instrument underwritten by the relevant electricity distribution network. The broader point is that securitisation opens a range of financial structuring options, including time-based discounting of asset write-downs, that could give distributors a workable basis for participating in managed network retirement rather than resisting it. The practical question for the Commission is whether the rule changes leave room for such mechanisms to be developed by jurisdictions, or whether they foreclose them.

Zonal decommissioning frameworks provide the institutional infrastructure for retiring segments of the network once the financial and planning groundwork has been done. International experience, including in California, the Netherlands, and parts of Denmark, provides examples of geographically targeted decommissioning where entire neighbourhoods

transition together rather than through household-by-household attrition. The efficiency advantages are substantial: lower cost per remaining customer, electricity augmentation planned for known transitions, and consumer support delivered at scale.

Neither mechanism is a matter for the National Gas Rules to resolve. Both are, however, relevant because the rules can either accommodate these approaches or impede them. We recommend that the Commission design the rule changes to keep these mechanisms available, by avoiding rule designs that assume household-by-household attrition, allowing partial redundancy and accelerated depreciation at defined geographic scales, and preserving flexibility in tariff design.

5.4 Victoria as the test case

Victoria warrants specific attention, not as an exception, but as the leading-edge case for what other jurisdictions will face on a slightly delayed timeline. Victoria has approximately 34,000 kilometres of gas distribution pipeline, around 2.2 million customers, and a residential gas penetration rate of approximately 80 per cent.

AEMO's 2026 Victorian Gas Planning Report identifies forecast decline in residential gas consumption alongside a forecast increase in gas-powered generation demand as the Eraring and Yallourn coal plants retire. CEPA's modelling identifies a switching point of approximately $2,660 per year, beyond which customer exit accelerates non-linearly. VEFN's analysis indicates that Victoria's fixed annual connection charge could rise from approximately $336 today to around $500 by 2035.

The rising fixed charge also creates an exit pathway that does not require full electrification. As gas hot water systems reach end of life and new homes are built all-electric, the remaining piped gas load for many households will converge on cooking. For these households, bottled LPG is already cheaper than maintaining a piped connection: market analysis identifies total cooking-only LPG costs under $200 per year, less than the current piped gas fixed charge alone (Elgas, 2023). As that charge rises towards $500, the one-off cost of a gas fitter converting a cooktop becomes increasingly trivial relative to the annual saving. Bottled LPG is explicitly exempted from Victoria’s gas substitution regulations, so this pathway is available now. Each household that takes it becomes a dormant connection, accelerating the cost recovery problem documented below.

One specific manifestation of these dynamics concerns dormant connections: sites where a customer has ceased taking gas but the connection remains in place. Every dormant connection represents a household that has moved on while the infrastructure that served it remains, and the cost of maintaining it falls on the neighbours who are still connected. Environment Victoria's submission documents a steady rise in the dormant share of Victorian residential Tariff V connections, from around 3.2 per cent in mid-2022 to around 4.4 per cent by late 2025 (Environment Victoria, 2026, Figure 3). The trajectory is most advanced in the ACT, where total residential dormancy has risen from 7.7 per cent in September 2022 to 13.3 per cent by December 2025, with connections dormant for more than twelve months alone accounting for 11.3 per cent of the residential base (AER, Gas quarterly disconnection

reporting, 17 February 2026). The ACT is also the only jurisdiction where the residential customer base is itself contracting.

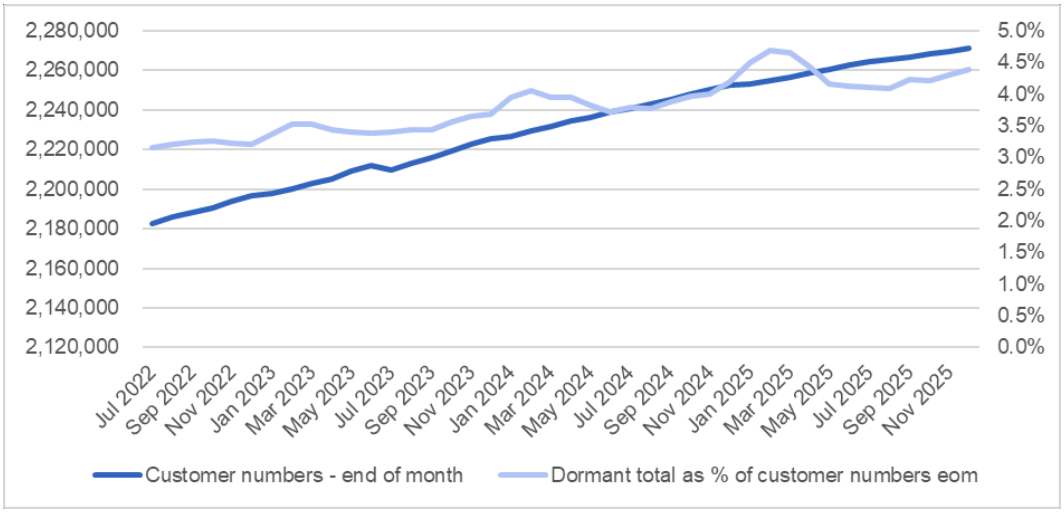

Figure 4: Victorian residential Tariff V customer numbers at end of month and the proportion which are dormant. Source: AER data, reproduced with permission from Environment Victoria, submission to GRC0082, April 2026.

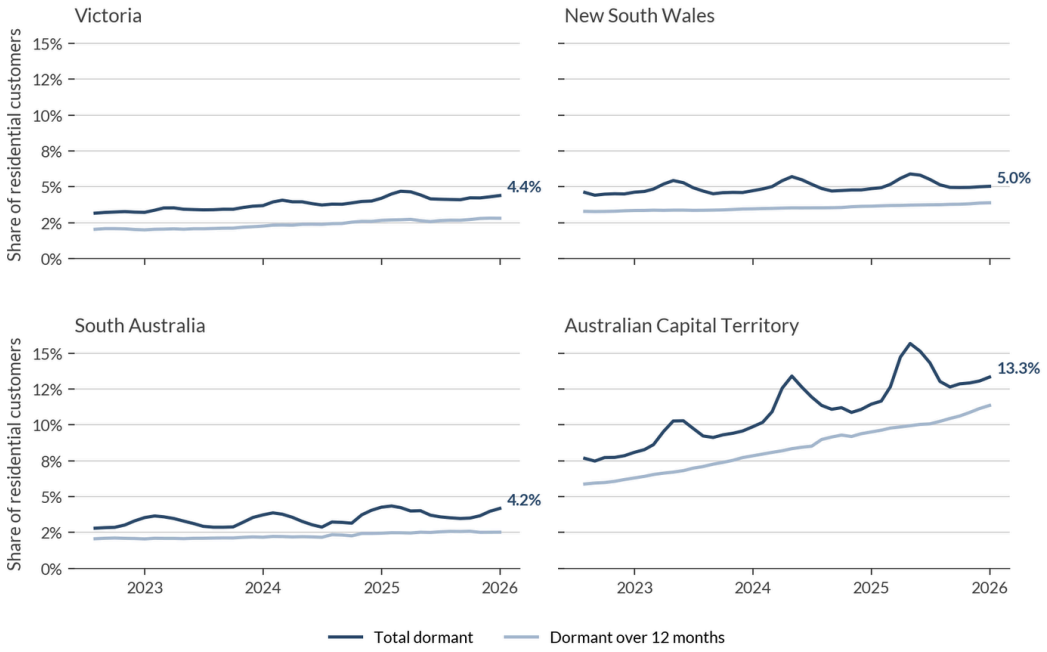

Figure 5: Residential gas dormant connections as a share of customer base by jurisdiction, July 2022 to December 2025. Source: AER, Gas quarterly disconnection reporting, 17 February 2026.

More revealing for the stranding question is what happens to infrastructure once a customer departs. Distributors predominantly retain the assets rather than remove them. In calendar 2025, only 32.7 per cent of Victorian residential disconnection events were abolishments; the remaining 67.3 per cent left the meter, the service line, or both in place. The corresponding abolishment shares were 38.8 per cent in South Australia, 18.9 per cent in New South Wales, and 13.8 per cent in the ACT (Figure 6). At 2025 abolishment rates, Jemena would require 22.9 years and Evoenergy 28.7 years to fully remove their existing residential dormant stock; the

Victorian networks would require roughly 9.6 years. This pattern is consistent with the current framework's incentive structure: assets left in place remain within the Regulated Asset Base and continue to earn a return, while abolishment is a cost typically funded from the remaining customer pool.

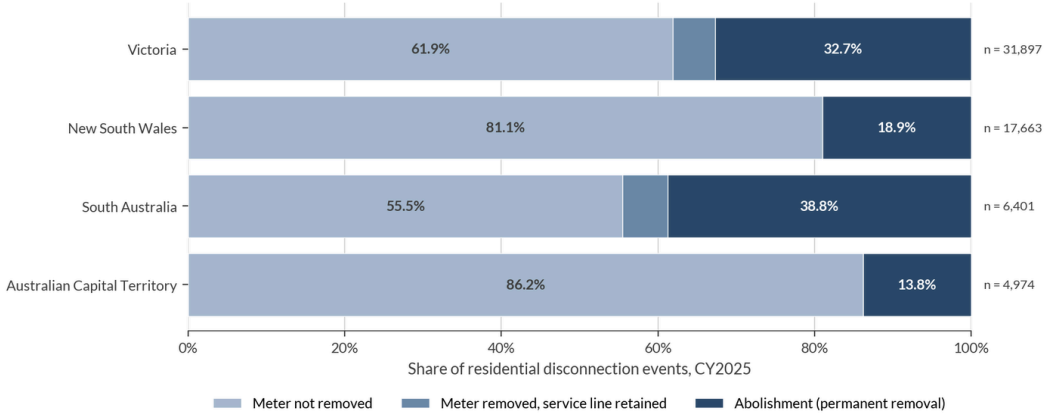

Figure 6: Residential gas disconnection events by type, calendar 2025, share of each jurisdiction's total. Source: AER, Gas quarterly disconnection reporting, 17 February 2026. n = total residential disconnection events recorded in each jurisdiction in CY2025.

Dormant connections fall outside existing frameworks for customer-initiated abolishment. No institution currently has clear authority or financial incentive to coordinate systematic abolishment as the stock grows. The rising share also raises safety and asset management questions in a network where an increasing proportion of infrastructure is in low-use or zero-use mode. Statutory recognition of dormant connections as a coordinated abolishment concern, with explicit allocation of cost recovery and institutional responsibility, would be a further element of the institutional reforms this section describes. The cost allocation dimension is developed in section 6.3.

Victoria is the test case for whether institutional reform of the kind described in this section can be delivered. The scale is large enough that the reforms matter. The policy settings are developed enough that the reforms have something to work with. And the timeline is advanced enough that they need to be designed now.

6. Cost allocation principles

6.0 Why cost allocation needs to be named separately

The GRC0082 reforms break the regulatory denial that has surrounded gas network decline. That is an important achievement. But breaking denial is not the same as allocating costs. Once the framework acknowledges structural decline, the question of who bears the residual cost becomes inescapable. If the principles for answering that question are not articulated, the default answer is the remaining gas customer base.

In practical terms, this means the families who are still heating their homes with gas in 2035 would bear an increasing share of the costs of a network that once served millions but now serves far fewer. The default is both regressive and self-defeating. It is regressive because the

remaining gas customer base increasingly consists of those who have not transitioned: renters without agency over appliance decisions, low-income households without upfront capital for electrification, elderly households for whom transition is complex, and occupants of older building stock with more difficult retrofit characteristics. It is self-defeating because the switching-point dynamic means that pushing charges higher accelerates further disconnection, shrinking the base and compounding the trajectory.

The Commission's proposed switching-point constraint (section 4.5) addresses this at the tariff level but does not resolve the underlying question: who bears the costs that the constraint prevents from being passed on to active customers?

This section sets out principles for allocating the residual stranding burden. The principles apply differently to different cost categories but share a common logic: costs should be allocated among investors, customers, and governments in ways that reflect the distribution of risk and benefit that actually applied when the underlying decisions were made, not determined by whichever party has the fewest degrees of freedom at the point of allocation.

6.1 The demand-risk asymmetry

To put this simply: for most of the last decade, gas networks were allowed to keep the profits when demand turned out higher than regulators forecast. The question now is whether they should be shielded from the losses when demand turns out lower.

More precisely, gas networks operated under a price cap form of regulation that exposed them to demand-volume risk by design. IEEFA's analysis of Australian Energy Regulator data shows that fully regulated gas networks generated an estimated $1.8 billion in supernormal profits between 2014 and 2022, on top of approximately $2.0 billion in regulator-approved profits. The single largest contributor (around two-thirds of the variance between allowed and actual returns) was revenue over-recovery driven by demand under-forecasting. Cost of debt outperformance against the regulatory benchmark contributed approximately one-third (discussed in section 6.2), and operating expenditure outperformance close to a fifth.

The case now being made for blanket accelerated depreciation without investor burden-sharing rests on shielding networks from the downside of the same risk parameter whose upside they retained for a decade. VEFN does not suggest that any individual network has acted improperly within the existing rules. We do suggest that the rules, as they are being amended, should not allow the upside of demand variance to remain with networks while the downside is transferred to a shrinking and increasingly vulnerable consumer base.

Two allocation principles follow. First, where networks seek accelerated depreciation, conditions should require investor burden-sharing commensurate with the benefit of the acceleration. The Energy Consumers Australia conditional-access model, which VEFN supports, includes a requirement for a demonstrated reduction in the Regulated Asset Base commensurate with the cost of acceleration. Without such conditions, accelerated depreciation risks delivering its theoretical benefits to networks while loading its tangible costs onto the customers least able to leave. Second, where networks have benefited from

sustained revenue over-recovery during periods of demand under-forecasting, the baseline for future demand-risk allocation should reflect that history rather than treating each access arrangement as an independent event.

6.2 Cost of capital as a cost allocation issue

At its simplest, this issue is about the gap between what regulators assume gas networks pay to borrow money and what they actually pay. That gap has been consistently in the networks' favour.

The Australian Energy Regulator maintains the Energy Infrastructure Credit Spread Index (EICSI), an empirical dataset constructed from actual debt issuance reported by regulated energy networks. Since its introduction, the index has consistently shown that actual borrowing costs sit below the benchmark cost of debt allowance. IEEFA estimates that approximately one-third of the supernormal profits earned by gas networks between 2014 and 2022 was attributable to this cost of debt outperformance.

During the 2022 Rate of Return Instrument review, the Independent Panel recommended that the EICSI be elevated from a sense-check to a primary input for setting credit spreads. The regulator declined, citing the limited dataset and concerns about preserving incentives for efficient debt issuance. Industry submissions supported keeping the index at the margin of the methodology.

The result is that the regulator possesses empirical evidence of persistent outperformance against its own benchmark, has had that evidence reviewed by its own independent experts, and has elected to maintain a methodology that produces allowances above the level the data supports. Industry financial sources familiar with regulated gas businesses have indicated that actual financing arrangements often diverge further from the standalone BBB+ benchmark than the EICSI captures. Networks are commonly held within consortium structures whose parent-level credit ratings exceed the regulatory benchmark, and gearing often differs from the assumed 60/40 debt-to-equity split.

During periods of network growth, allowing networks to retain this difference could be defended as an incentive for efficient debt management. In a network in structural decline, the same arrangement transfers value from a shrinking customer base to network owners without the offsetting policy justification. Maintaining the current methodology in a declining market is itself an allocation choice.

VEFN does not ask the Commission to determine the cost of capital. That is properly the AER's role. We do ask the Commission to: first, acknowledge explicitly the connection between the effectiveness of the GRC0082 package and the cost of capital framework, particularly during declining demand; second, engage with the AER on the interaction between GRC0082 reforms and the 2026 Rate or Return Instrument (RORI) process; and third, consider whether the rules should require transparent disclosure of the relationship between actual financing arrangements and regulatory benchmark assumptions, as part of the 20-year outlook or the access arrangement process.

6.3 Active customers, dormant customers, and the cross-subsidy question

Where a customer has disconnected or ceased taking gas but the connection remains in place, maintenance costs continue to be recovered through charges on active customers. The rising share of dormant connections in Victoria (section 5.4) represents a growing cross-subsidy from active to dormant customers. This cross-subsidy is largely invisible in the current regulatory framework and is asymmetric: active customers bearing the cost typically have fewer options than the dormant customers whose connections they are maintaining.

The cost allocation principle is that dormant connection costs should not fall by default on active customers. Options include: coordinated abolishment programs that retire dormant connections systematically; recovery of costs from the departing customer at the point of disconnection; or socialisation through government mechanisms, on the basis that dormant connections are a transitional artefact of the broader energy transition.

VEFN does not propose a single answer. The principle is that the status quo, in which the cross-subsidy grows with the dormant connection share, is neither equitable nor sustainable.

6.4 Principles for allocating the residual stranding burden

Drawing together sections 6.1 through 6.3, VEFN proposes five principles for allocating the residual stranding burden.

First, equity investors should bear a reasonable share of the burden, reflecting that they captured the upside of demand variance during the decade when demand was over-forecast. The ECA conditional-access model for accelerated depreciation is one mechanism.

Second, active customer charges should be constrained in ways that reflect the switching-point dynamic. The Commission's proposed switching-point standalone cost constraint is consistent with this principle.

Third, cost-of-capital allowances should reflect actual financing conditions in a declining market, not benchmarks designed for stable or growing infrastructure.

Fourth, the cross-subsidy from active to dormant customers should be recognised and addressed.

Fifth, government mechanisms may be required for portions of the stranding burden that cannot be equitably allocated to investors or remaining customers. These should complement, not substitute for, investor burden-sharing. Treating government support as the primary mechanism would shift costs to taxpayers, raising distributional questions of its own and creating moral hazard if investors can expect government backstops when demand underperforms.

7. Conclusion

The Commission's proposed package represents a substantial and necessary improvement on the status quo. VEFN supports the overall direction.

This submission has argued that the package's effectiveness will depend on three further elements: the institutional reforms that sit beyond the Commission's powers, the cost allocation principles that will guide how the residual stranding burden is shared, and the coordination function needed to sequence gas retirement with electricity augmentation at the zonal level.

These elements are mutually dependent. Rule changes without institutional reforms will apply in a vacuum. Institutional reforms without rule changes will lack the regulatory machinery to operate through. Either set of reforms without cost allocation principles will leave the residual stranding burden to fall by default on the customer base least able to bear it. The strongest version of the GRC0082 reforms is one designed to accommodate, and where possible to enable, the institutional architecture and cost allocation principles that will need to emerge if the energy transition is to deliver the consumer benefits it promises.

We would welcome the opportunity to discuss any aspect of this submission with the Commission.

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Victorian Energy Future Network

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