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EnergyAustralia
LIGHT THE WAY

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Future Gas Strategy – Consultation Paper – 3 October 2023

EnergyAustralia is one of Australia's largest energy companies with around 2.4 million electricity and gas accounts across eastern Australia. We also own, operate and contract a diversified energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 5,000MW of generation capacity.

We appreciate the opportunity to comment on the Commonwealth Government's proposed Future Gas Strategy. The Strategy will be timely as there is now a critical need for a definitive, whole-of-government vision for Australia's gas sector over the medium to long term. Last year's events demonstrated that governments and industry have few levers at their disposal to shield customers from short term price shocks, and that our local markets are fundamentally linked to international dynamics. Without significant investment in new supply, we also face the risk of gas shortfalls on the east coast within a few years. Investment in capital-intensive gas infrastructure is challenging because of stranding risk and increasing demand volatility as we decarbonise, compounded by the lack of a coherent long-term policy and project approvals framework. Growing supply scarcity will put upward pressure on gas prices well before customers experience actual shortfalls. The price control mechanisms recently introduced to protect customers were designed in haste, reflecting the urgency of events last year. These will need to be reviewed and give way to more durable arrangements that protect customers against high prices while also preserving investment incentives.

Reducing our dependence on gas will improve domestic resilience to international shocks, mitigate the risk of supply shortfalls, ease pricing pressures and meet our decarbonisation objectives. Analysis of decarbonisation pathways overwhelmingly shows that electrification of domestic, industrial and transport sectors will be the least cost and feasible means to reach emission reduction targets. The pace of electrification needs to dramatically accelerate however the replacement of gas appliances for domestic customers will still take time. Gas will still be needed in the medium to long term for other customer segments where there are limited fuel substitutes. Gas-fired generation will also be necessary to support the significant upscaling of wind and solar generation, to facilitate the exit of large coal generators, and to complement long duration storage which is subject to its own challenges at present. The growing intermittency of gas usage within an overall declining trend creates challenges for infrastructure owners, as well as customers, in determining fair and sustainable methods of cost recovery.

The Government's Strategy will be an important opportunity to explore these fundamental challenges with a broad range of stakeholders. We do not expect it will outline clear solutions, which will be the subject of separate and more detailed deliberation. The Strategy can play an important role in framing further discussions by recognising the nature and severity of different challenges, and where coordinated action from all governments is necessary. The Government can set out its own role across various agencies in terms of managing security of gas supply, price, emissions reduction, industry development and international trade, including as it affects adjacent sectors like electricity and transport. Setting out this role in a clear and transparent manner will enable industry to plan and ultimately deliver gas supply in a way that maximises value for customers. In our view, the Strategy should:

- identify the need for **government intervention to overcome the risks in investing in new supply sources** that are now urgently needed to address expected supply shortages in the east coast from as early as 2027

- provide a clear policy commitment across all levels of government that **electrification is the most effective means to decarbonise** energy and adjacent sectors. This includes setting ambitious but realistic timeframes that help shape further measures to address stranding risk for gas infrastructure

- underpin the transition from the customer side by ensuring sufficient **incentives for customers to electrify** their current gas usage where this is possible, while **preserving gas supply options for customers that cannot switch,** particularly large industrial users

- facilitate a **nuanced public discussion around the role of gas-fired power generation** and its emissions impacts as the technology mix in our electricity supply fundamentally changes in the coming decades

- set out the roles for government, regulators, customers and asset owners to jointly deal with the **stranding risk for owners of gas network and other infrastructure** as gas demand declines and becomes increasingly intermittent.

These recommendations are expanded in the attached.

If you would like to discuss this submission, please contact me on 03 9060 0612 or Lawrence.irlam@energyaustralia.com.au.

Regards

Lawrence Irlam
Regulatory Affairs Lead

Attachment

Governments must intervene to bring on new upstream supply

AEMO and the ACCC have been forecasting shortfalls for the east coast for several years and this should be providing strong signals for new investment. There are, however, barriers to committing to capital-intensive investment which have been compounded by recent price interventions. We consider that bringing on new and sufficient supply requires some form of government underwriting or risk transfer arrangements. Further below we offer views on relevant commercial characteristics and policy objectives that could be developed in the Strategy or in further public consultation.

Market barriers to investment

It was once considered anomalous that liquified natural gas (LNG) import terminals could be required in Australia given its large domestic gas reserves. Relative to onshore production, import terminals can be better located relative to demand centres and so avoid expensive pipeline infrastructure, with less overall capital outlay and greater commercial flexibility. To our knowledge, the import terminal being constructed at Port Kembla still does not have any off-takers and we do not expect such an approach will be repeated even if it is successful. The recent tentative announcement regarding the Venice terminal would have Origin as the sole off-taker for all import capacity. This type of arrangement suggests that suppliers using new facilities, in the context of declines in conventional production sources, could wield market power in a sustained manner and so may warrant responses from a policy or regulatory perspective.

The extent of forecast shortfalls, combined with construction lead times, should warrant a market response beyond the scale and scope of these two projects. Gas production and transport infrastructure is underpinned by long-term contracting arrangements, which can only be agreed to where risk can be reasonably priced by market participants. Participants are reluctant to contract beyond the short term and we expect this to continue. AEMO's 2023 Gas Statement of Opportunities (GSOO) listed investment challenges arising from carbon risk and associated planning decisions which are on top of more transitory disruptions due to international factors.[1] Companies typically like investing into growth areas with at least a balanced outlook for under- and over-performance of an investment case. The medium to long term market outlook is one with falling demand in line with emissions reduction objectives, and with upside returns truncated by the threat of higher resource taxes or government price intervention at the wholesale as well as retail levels.

Effect of the Code of Conduct

The imposition of the Competition and Consumer (Gas Market Code) Regulations this year has made contracting more complex, which will affect investment decision-making. The Code's headline feature was to set a price cap of $12/GJ, which is intended to deliver meaningful price protections to customers in the context of broader cost of living pressures. The Code provides for exemptions from the price cap with the explicit intention of incentivising producers to commit more gas to the east coast market.[2] Whether the Code on balance provides positive investment incentives is questionable given:

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[1] AEMO, *Gas Statement of Opportunities*, March 2023, pp. 87-8.

[2] Compliance guidelines for gas industry as new Gas Market Code takes effect | ACCC

- it is unclear yet whether the Code's process requirements, combined with other published information, will enable consumers and producers to form reasonable price expectations, such that contracting incentives and price discovery become self-reinforcing, or whether parties will instead test the limits of the Code and ultimately rely on ACCC intervention

- administration of the exemptions framework is unclear, resting largely on Ministerial discretion and producers offering enforceable but bespoke gas supply commitments

- the government's $12/GJ value reflects expectations of reasonable costs of incremental domestic supply.[3] It is not clear whether governments or customers would tolerate full export price parity[4], even in the absence of global supply shocks. The ACCC's advice leading to the setting of the cap was predicated on imposing an interim emergency measure, and so reflected the costs of currently producing gas fields. However, this value and its reference to the cost of production may now represent a benchmark for future developments. This includes gas supplied by LNG imports, which will be closely tied to international market dynamics and the opportunity cost of global pricing, rather than 'bottom up' costs of production

- the government has now demonstrated a willingness to impose price caps and at short notice. The tight domestic supply conditions forecast in the coming years seem likely to drive scarcity pricing again, with the credible risk of ongoing or expanded interventions

- there appears to be no intention for the Code to be removed if the market shows signs of returning to 'normal' supply and demand conditions. The Code provides for ongoing ACCC price oversight functions and the powers to make 'reasonable price' determinations from 2025. Scheduled reviews of the Code seem likely to result in administrative refinements and an increasing dependence on ACCC intervention rather than market outcomes

- it is unclear whether similar Code requirements will apply to downstream to retail pricing. The ACCC recently commented that it will review retailer pricing and behaviour and advise the Government where issues are apparent.[5] The credible threat of retail price regulation would deter long-term contracting, or at least promote practices that match regulatory benchmarks, with flow-on effects to upstream investment

- the Code interacts with other mechanisms like the Heads of Agreement, the Australian Domestic Gas Security Mechanism and AEMO's new intervention powers[6], and the market outcomes of these will be difficult to predict. Any uncertainty in these interactions would have some effect on smaller and purely domestic producers even though they are excluded from direct price regulation.

[3] Summary of the Australian Competition and Consumer Commission Advice to Government (treasury.gov.au)

[4] The ACCC recognises this with respect to Queensland LNG export, see LNG netback price series | ACCC

[5] ACCC, *Gas Inquiry 2017-2030 Interim update on east coast gas market*, June 2023, p. 13.

[6] Proposed regulatory amendments to extend AEMO's functions and powers to manage east coast gas supply adequacy | energy.gov.au

Further options for government in bringing on new supply

The Energy Ministers' secretariat recently canvassed the concept of a 'reliability and supply adequacy' contracting obligation which would seek to correct the problem of missing markets for long-term offtakes.[7] It would have obligated retailers and large customers to forward purchase in the face of reliability gaps, but with various shortcomings as raised in our consultation response.[8] The Commonwealth should, however, continue to explore the nature of risk faced by market participants regarding supply adequacy and learn from how this is being dealt with in other markets. In our view there are several salient aspects of this risk, specifically for LNG import and related infrastructure:

- the scale and configuration of necessary infrastructure will need to correspond to acceptable levels of risk over different timeframes and geographies (these issues were raised in the Ministers' recent 'stage 2' reliability framework paper). This will affect the LNG storage required to provide daily and seasonal buffers, as well as the size and location of connecting pipelines.

- there are likely to only be few candidate LNG terminal investments but each at considerable scale, potentially giving rise to third party access issues

- missing forward markets and contracting needs to extend well beyond the 3 year horizon that might have been associated with reliability obligations and triggers. For example, Origin's anticipated offtake for the Venice project would extend to at least 10 years[9]

- investors need some degree of confidence that sales volumes will be sufficient and sold at prices to cover capital costs. By the same token, users require clarity on their own emissions and gas consumption constraints in order to assess their risk exposure, which feeds back into demand forecasts for infrastructure investors.

Exploring these risk elements might assist in developing options or design features regarding government intervention:

- there is likely a greater need for 'centralised' rather than market-led solutions in the gas context relative to (for example) electricity, given structural declines in demand and stranding risk

- the higher capital intensity of individual investments (in addition to declining demand) adds financial risk but also gives rise to market power concerns. Hence there are justifications for regulated access and pricing outcomes from the customer as well as developers' perspective

- any arrangements that involve centralised bidding or auctions for supply agreements could also coincide bids on the demand side, even if these are insufficient to underwrite investment on their own

- supply as well as demand side risks could be mitigated by government taking a 'last resort' procurement option for any unmet demand. Supply arrangements could

[7] Consultation on Stage 2 of the Reliability and Supply Adequacy Framework for the east coast gas market | energy.gov.au

[8] https://www.energyaustralia.com.au/sites/default/files/2023-07/Reliability%20and%20supply%20adequacy%20framework%20for%20the%20east%20coast%20gas%20market%20-%20consultation%20paper_13%20July%202023.pdf

[9] VE-231027-MR-OriginExclusivity_Final.pdf (veniceenergy.com)

involve government "buy back" of any stranded asset value if volumes decline below a threshold level, with such a quantity threshold and purchase price subject to competitive bidding. This model could be employed in conjunction with stranded network assets (see below)

- any centralised government purchases or risk-taking would involve taxpayer exposures, offset by government onselling at a potentially higher 'backstop' price where volumes are needed (akin to last resort arrangements for AEMO)

- at the extreme, supply facilities could be designated as regulated monopolies with prices determined via periodic competitive auctions (bidding 'for the market'). Direct government ownership could also be considered, with all profits and losses directly passed onto taxpayers.

Governments need to commit to a high electrification pathway

Decarbonisation will only be feasible with high degrees of electrification, with most customers reducing gas usage and eventually disconnecting from gas networks. This is backed by all credible studies including internationally by the IEA as quoted in the consultation paper[10], and others in the Australian context[11].

Various policies already in place or proposed by federal and jurisdictional governments support electrification. The Commonwealth's Strategy should strengthen this with an overarching long-term commitment, which also explicitly rules out large-scale renewable gas as an alternative solution. Victoria's recent announcement to ban gas connections in new residential dwellings from next year highlighted divergent policies in other jurisdictions, including at the local council level.[12] Ongoing policy ambiguity creates the space for owners of gas infrastructure assets to promote their own studies[13] that (in our view, erroneously) suggest large scale renewable gas is a cheaper emissions reduction pathway. Deferring commitment to electrification creates the risk of 'locking in' gas assets and associated emissions, compounds the impact of asset stranding, and adds to 'death spiral' price pressures (discussed below).

The Strategy should identify a realistic and credible timeframe for gas switching as part of promoting an orderly transition. Providing some degree of certainty on this timing will help identify the volumes and temporal shape of gas demand and assist in de-risking new supply (irrespective of any government involvement discussed above). The effect of this would also be to ease supply shortfalls via demand response, thus helping minimise volatility in gas prices as well as in related electricity generation.

The Strategy should assess the existing level of market and government incentives that promote electrification, and identify how these can be augmented to ensure the rate of gas switching is realigned towards a net zero trajectory. This should reflect existing and credible analysis[14] already done at the household level, looking at payoffs and upfront cashflow barriers for households, and the timing of likely appliance purchasing decisions. The effects of gas substitution at the network and wholesale level should also be assessed to determine bill impacts from a whole-of-energy perspective, which will have feedbacks into switching incentives and hence rates of uptake. The Strategy should identify

[10] See for example Credible pathways to 1.5°C – Analysis - IEA

[11] See for example netzeroaustralia.net.au/wp-content/uploads/2023/04/Net-Zero-Australia-Modelling-Summary-Report.pdf

[12] Gas lobby pushing back as momentum builds to get new homes off the fossil fuel - ABC News

[13] Gas Vision 2050 | Energy Networks Australia

[14] Getting off gas: why, how, and who should pay? (grattan.edu.au)

opportunities for cross-sectoral planning and coordinated government policy. It will need to encourage private sector innovation to manage usage profiles and maximise utilisation of electricity assets. Generally speaking, lowering overall energy demand will be critical in prioritising scarce gas fuel for industrial users and in power generation. Hence coordinated policies across energy efficiency, electrification, transport and emissions need to be developed.

We need credible policy support for customers who cannot electrify

EnergyAustralia is supportive of hydrogen and renewable gas as an alternative to carbon intensive 'natural gas' in situations where electrification is uneconomic or infeasible.

As noted in the Commonwealth's consultation paper, many large industrial customers operate high-heat processes that depend on the use of a gaseous fuel where blending of biomethane or renewable hydrogen will need to be explored. In other circumstances, customers may be able to implement solutions to electrify their gas use and achieve reduced emissions intensity. These types of solutions are likely to be technically specific to a customer's process and we are helping our own customers access renewable electricity where possible. We are also exploring the potential of our Tallawarra B gas power station to be ready to accommodate blended renewable hydrogen where its supply is commercially viable.

For industrial users with continuing reliance on gas, it is important to ensure that gas is prioritised for their needs while other sectors of the community with potential to electrify are engaged more proactively in that pathway. In this way, industrial users could be spared some of the pressures on pricing that local supply constraints might otherwise bring forward. Where renewable hydrogen may be available, these users can then manage the technical limits on the rate of hydrogen gas blending that their equipment and processes can tolerate. It is worth noting biomethane is identical to the natural gas it is replacing, whereas renewable hydrogen requires significant capital investment for blending beyond small percentages.

Noting the current high cost of living pressures, and the prospects of ongoing tight demand-supply balance for gas, we support emission reduction use-cases via renewable gas blending provided that infrastructure and commodity costs are not raised without the explicit involvement and consent of end users. Available sources of renewable gas are volume constrained, and the mechanisms that will enable production levels in line with long term decarbonisation scenarios, and at a reasonable cost, are uncertain.

The NSW Hydrogen Strategy[15] and others[16] adopt a target or long run production cost of between $2 and $3/kg which would still likely exceed the cost of natural gas on an energy equivalent basis. The NSW Government has legislated a Renewable Fuel Scheme which would require retailers, on behalf of customers, to purchase certificates that equate to 8,000,000 GJ of renewable hydrogen by 2030.[17] The commencement of this scheme has been deferred however the expectation appears to be that the cost of purchasing certificates would be passed onto gas consumers, with exemptions for emissions intensive and trade exposed industry. The Victorian Government also recently published a consultation paper[18] outlining a potentially similar scheme. This raised important questions

[15] NSW Hydrogen Strategy
[16] 18-00314_EN_NationalHydrogenRoadmap_WEB_180823.pdf
[17] Renewable Fuel Scheme | NSW Climate and Energy Action
[18] https://engage.vic.gov.au/victorias-renewable-gas-consultation-paper

regarding how scheme targets would be calibrated and costs recovered from gas and electricity customers.

There is a role for the Commonwealth to try seek alignment across jurisdictional interventions in order to determine the total volumes of renewable gas that might be required in the medium to long term. Policies that target both the demand and supply side can then be meaningfully discussed and coordinated nationally such that gases are produced by, and consumed in, technical processes which minimise the total cost of carbon abatement. For example, costs might be minimised where production sources are located next to points of consumption to minimise the need for hydrogen transport, which is unlikely to be feasible using existing gas pipeline materials or configurations. Locational decisions also need to accommodate the output and pricing profiles of electricity generation which could be sourced from the grid (with a renewable guarantee of origin) or co-located wind and solar generation. Again this highlights that the Strategy should integrate with sectoral planning in electricity and well as industrial development.

We need a nuanced discussion about the role of gas generation and to explicitly deal with emissions in the power sector

The broader role of gas in the transition is still subject to considerable debate. Much of this stems from the lack of a nationally consistent and coherent policy that explicitly deals with emissions in the power sector. While energy and emissions policy continues to develop, the Government's Strategy can play an important role in introducing nuance to the discussion around gas generation.

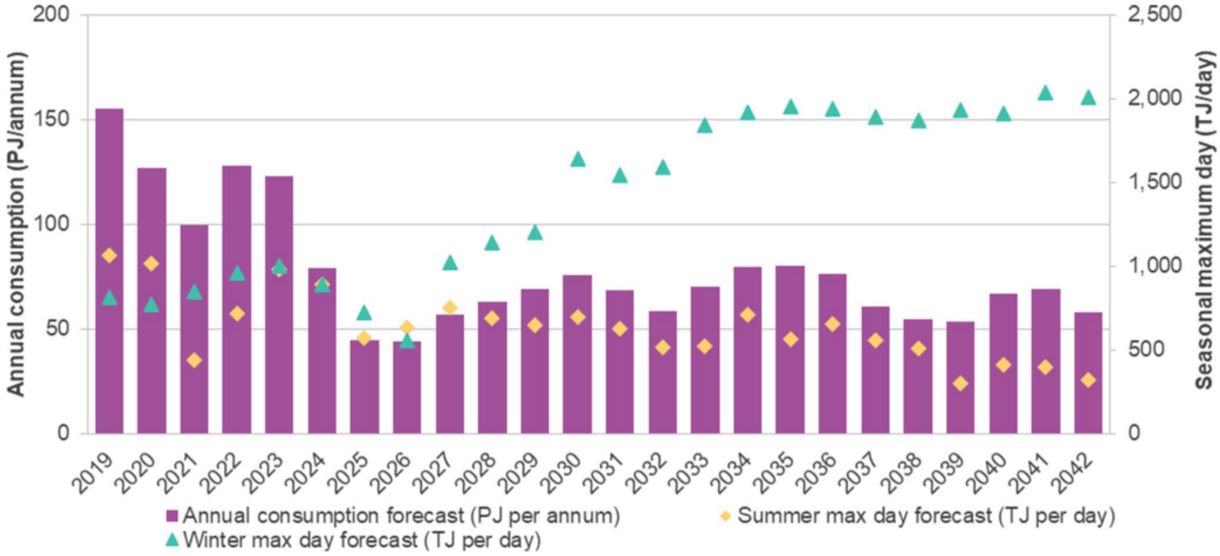
The Commonwealth's consultation paper highlights AEMO's analysis, showing gas-powered generation (GPG) is expected to play a critical role in meeting customer reliability, with much more intermittent output as we transition to a renewables-dominated power system. The scenarios in AEMO's Integrated System Plan reflect long term carbon constraints, such that its projections of GPG usage and emissions are still consistent with net zero objectives. The new requirement for AEMO and others performing long term modelling under the National Electricity and Gas Rules to explicitly value emissions reduction[19] should draw specific attention the total amount of emissions associated with gas peaking plant. At present, GPG appears to have been overly politicised in Australia, and was recently excluded from the federal government's Capacity Investment Scheme. We recognise the preferences of several jurisdictions and stakeholders to oppose fossil fuel projects as a means to curb dangerous global temperature increases. However a more certain way to achieve this objective is via a transparent and methodical analysis of emissions impacts, rather than in taking binary or ideological viewpoints. Without support for GPG, jurisdictional governments that face reliability risks with the accelerated closure of coal generators seem to have limited options but for supporting the life-extension of these coal generators. This would seem to be suboptimal from the perspective of price, emissions and reliability, noting it departs from the technology mix in AEMO's ISP scenarios.

The energy output from gas-fired generators in some of the 2022 ISP scenarios reflects a significant step increase from now to the 2030s. This is inconsistent with GPG consumption in AEMO's GSOO outlooks. We understand the Commonwealth is looking to 'supercharge' the ISP by enhancing AEMO's consideration of cross-sectoral impacts. Better ties between electricity and gas sector projections should either underline the risk of gas supply shortfalls in the GSOO, or rule out so much reliance on gas in the ISP, with likely

[19] Harmonising the national energy rules with the updated national energy objectives (electricity) | AEMC

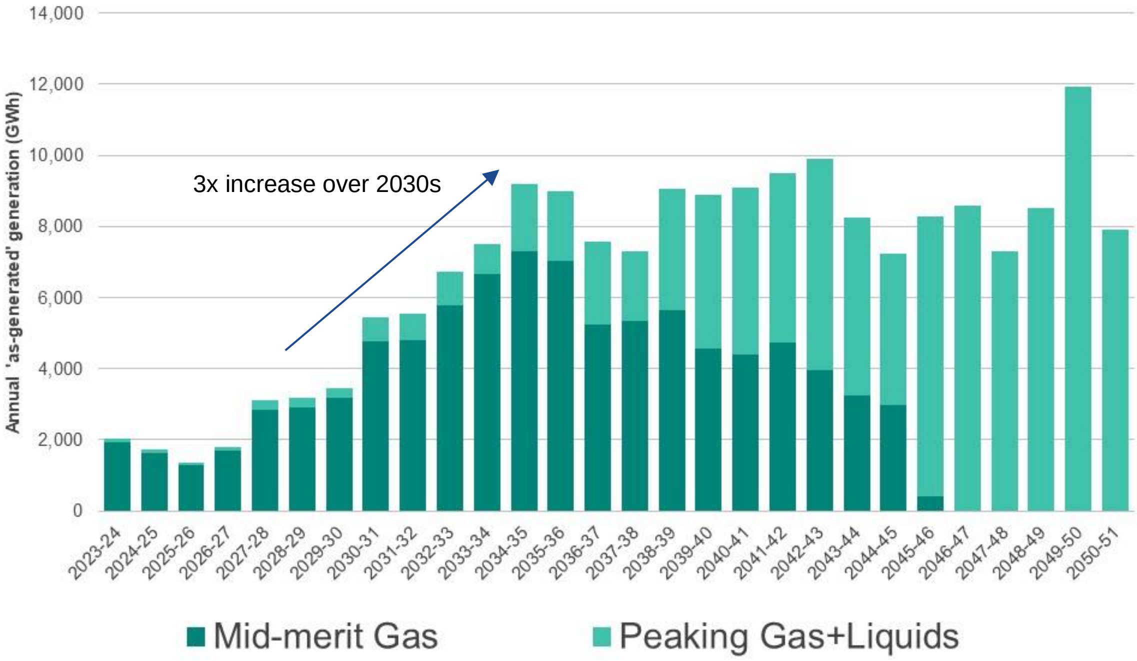
need for more expensive flexible generation and storage technologies. This notwithstanding, there is scope for the Strategy to draw out the implications of ongoing gas generation out to 2050 in terms of gas fuel adequacy and for reliability in the NEM.

Figure 23 Actual and forecast gas generation annual consumption (PJ/y) and seasonal maximum daily demand (TJ/d), *Orchestrated Step Change (1.8°C)* scenario, 2019-42



Source: AEMO Gas Statement of Opportunities March 2023, p. 45.

AEMO 2022 ISP Step Change scenario, gas generation output



Source: "2022 Final ISP results workbook – Step Change – updated inputs.xls", NEM generation by year

Speaking to our own portfolio of assets, as coal generation is progressively phased out, we still see gas playing a key role in flexible generation capacity that is needed for system resilience into the 2040s. Gas generation can provide duration as well as flexibility. Duration is important as we move into a system where most of our electricity comes from renewable sources, with occasional lulls in wind and solar output. Ultimately this means gas generation supports the upscaling of variable renewables, which should lower overall costs for customers. Gas generation is also likely to provide backup if there are delays in bringing on new transmission and large storage projects like Snowy 2.0, and where coal generation leaves the system earlier than expected or is subject to unexpected outages.

Government action is required to address pricing pressures from gas networks

Electrification and reduced gas consumption will have important network impacts, with potentially significant price effects for our customers. To manage this, the Strategy can outline the following roles for Australian governments:

- provide clarity on their stance regarding electrification (as outlined above)
- set a coherent and targeted set of assistance measures for mass market and large industrial customer segments, as well as ensuring regulatory and market settings incentivise gas switching where it is feasible
- reconsider the regulatory model for gas networks.

For gas networks, having customers electrify and switch away leads to a 'death spiral' type situation, as asset owners still need to recover high fixed costs from a shrinking customer base. We have been engaging on this issue alongside many other stakeholders in recent AER access arrangement determinations. Within the existing rules framework, the AER and regulated gas networks have been using accelerated depreciation as a way (and possibly the only way) to try deliver long-run price stability. The recent round of access reviews for gas distribution networks in NSW, ACT and Victoria all highlight that network businesses continue to invest in existing and new assets because of safety obligations or to provide option value where renewable gases can be delivered commercially and at scale. The AER highlighted these and related issues in November 2021.[20] Given the inevitability of electrification, there will be a residual amount of customers that face switching barriers, in the form of capital outlays for domestic appliance switching, and the lack of gas alternatives for some large industrial customers. The full cost recovery of network assets for this diminished customer base could only be done through prices that are unsustainably high. Growing price pressures in the interim will likely require regulatory or government intervention.

In the near term, gas networks should be prohibited from offering incentives for customers to upgrade gas appliances, or to replace electrical with gas appliances.[21] There also needs to be general policy and regulatory guidance for the AER on charging exit or abolishment fees. The AER's recent decision to socialise abolishment fees as part of its Victorian distribution access decision was only an interim measure[22] and requires government intervention to ensure a more sustainable solution across all jurisdictions.

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[20] AER Information Paper - Regulating gas pipelines under uncertainty - 15 November 2021.pdf

[21] Energy crisis: Gas company offers cash to plug electric exodus (smh.com.au)

[22] AER decision supports Victorian gas consumers in energy transition | Australian Energy Regulator

For the longer term, there is a need to revisit how gas networks are regulated. Asset values are prescribed in the National Gas Rules, without provisions that allow any revaluation in spite of significant and growing carbon risk. Prior to the move to national regulation by the AER, jurisdictional energy regulators engaged in asset revaluations at each determination, although not without controversy. If there is sufficient policy imperative, there may be scope now for governments to broker some form of burden-sharing arrangement that provides for a fair and equitable write down of asset values between customers, network owners and potentially taxpayers. Such a discussion can only take place where governments have made credible commitments to electrification and provided other customer support as noted above.

For electricity networks, if electrification is done without managing asset utilisation, it could also add higher overall costs for customers. The solution here is for more granular definition of asset services and with prices that are more cost reflective. This would enable retailers and aggregators to offer products and technologies that minimise total system costs, and share that value with customers. Governments need to encourage this innovation, which means having more faith in competition than in direct price regulation to deliver customer outcomes.