18 September 2026

Submission: 2026-27 Safeguard Mechanism Review

The Australian Pipelines and Gas Association (APGA) represents the owners, operators, designers, constructors and service providers of Australia's pipeline infrastructure. Our members deliver more than 1,500 PJs of natural gas each year for domestic use and over 4,500 PJs for export markets, underpinned by the highest standards of safety, reliability and operational performance. For decades, this infrastructure has been a cornerstone of Australia's economic strength, providing secure, low-cost energy that has supported growth, sustained long-term trade, and enabled industry to compete globally.

APGA welcomes the opportunity to provide comment to the Department of Climate Change, Energy, the Environment and Water (DCCEEW) in the 2026-27 review of the Safeguard Mechanism. Regular reviews of the settings of the Safeguard Mechanism are appropriate and necessary to ensure that its operation is meeting Australia's emissions reduction needs, and to that end DCCEEW has limited the scope of this review.

APGA recognises that it is appropriate to limit the scope of consulting in order to make it tractable to review and assess feedback. However APGA emphasises that there are dependencies between the Safeguard Mechanism and the National Greenhouse and Energy Reporting Scheme (NGERs). From the perspective of the gas transmission pipeline industry, NGER has certain deficiencies in its measurement framework, and this is fundamental to the ability of those facilities to meet their current and future obligations under the Safeguard Mechanism.

Amendments to the Safeguard Mechanism to emphasise on-site abatement may end up being a welcome incentive for DCCEEW to put serious effort behind amending NGERs to ensure it is fit for purpose, but in the meantime, facilities that lack access to top-down (or 'higher order') methods for methane detection and measurement will not be able to practically reduce on-site emissions, and will be left with few options for complying with their Safeguard obligations beyond utilising offsetting through the use of Safeguard Mechanism Credits (SMCs) or the ACCU scheme.

Any changes to the settings of Safeguard Mechanism must take into account external factors, including limitations in NGERs, which will make it difficult if not impossible for gas transmission pipeline facilities to reasonably comply with increase obligations.

Lifting barriers to on-site abatement

Are there any remaining barriers to undertaking on-site abatement, including sector-specific barriers? Are there any important areas that are not covered by government policy or programs?

Reforms to the Safeguard Mechanism to further incentivise on-site abatement is understandable and an approach with which APGA broadly agrees. However, this must only come once frameworks are in place that enables facilities to actually measure and demonstrate onsite abatement. Currently the ability of gas transmission (and distribution) facilities to do so is limited from a practical standpoint by both the cost of abatement technologies and processes and the absence of methods to accurately measure and report methane emissions. To sum the latter, you cannot reduce what you cannot measure.

Direct measurement of emissions (which form the basis of "higher order" emissions reporting methods) is commonly used and often required by regulators overseas (such as in the EU, Japan and Korea). In the oil and gas sector, the UN Environment Programme's Oil and Gas Methane Partnership 2.0 (OGMP 2.0) is considered the 'gold-standard' scheme which requires reporters to shift from generic emissions estimates to higher order methods.

APGA encourages looking to best practice nationally and overseas in the emissions measurement space, to enable domestic frameworks to make use of transparent and readily accessible methodologies in this space. That being said, APGA does not necessarily recommend a direct implementation of the OGMP2.0 approach to the Australian context. For instance, membership of OGMP2.0 puts a time limit on moving to the highest order method (the Gold Standard), which may not be reasonable or necessary for Australian facilities.

Aspects of the framework can and should provide a basis for developing methods 4 and 5 for the Australian oil and gas sector, although until recently, openly available information (i.e. without membership) on OGMP's approach emissions detection and broad reconciliation has not been available. However, in Australia, even initiating programs with this approach is simply not yet capable of being recognised under NGERs.

Gas facilities currently cannot demonstrate onsite abatement

Gas transmission facilities currently have three methods available to them for estimating onsite fugitive emissions. Importantly, none of the available methods under NGERs allows facilities to demonstrate *changes*, including reductions, in those emissions estimations or differentiate, for example, between leaking components and non-leaking components. This requires "higher order" methods which are not currently available for transmission pipelines or indeed the majority of the resources sector.

Method 1 is a simple calculation based on a standard emissions factor for methane per kilometre of pipeline. To reduce fugitive emissions for these facilities requires physically shortening the pipeline, an unassailable practical limitation. Nevertheless, all transmission pipeline facilities currently use Method 1, which likely provides an underestimate of emissions relative to direct measurement, as Methods 2 and 3 have additional considerations that make them even less practical.

> **3.76 Method 1—natural gas transmission (other than flaring)**
>
> Method 1 is:
>
> $$E_{ij} = (L_i \times EF_{ij})$$
>
> where:
>
> $\boldsymbol{E_{ij}}$ is the fugitive emissions (other than flaring) of gas type (***j***) from natural gas transmission through a system of pipelines of length (***i***) during the year measured in CO_2-e tonnes.
>
> $\boldsymbol{L_i}$ is the length of the system of pipelines (***i***) measured in kilometres.
>
> $\boldsymbol{EF_{ij}}$ is the emission factor for gas type (***j***), which is 0.02 for carbon dioxide and 11.6 for methane, measured in tonnes of CO_2-e emissions per kilometre of pipeline (***i***).

Method 2 uses emissions factors for separate components, varying the amounts of gas/condensate.

> **3.77 Method 2—natural gas transmission (other than flaring)**
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> (1) Method 2 is:
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> $$E_j = \sum_k (Q_k \times N_k \times EF_{jk})$$
>
> where:
>
> $\boldsymbol{E_j}$ is the fugitive emissions (other than flaring) of gas type (***j***) measured in CO_2-e tonnes from the natural gas transmission through the system of pipelines during the year.
>
> $\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas transmission.
>
> $\boldsymbol{Q_k}$ is the total of the quantities of natural gas or plant condensate measured in tonnes that pass through each equipment type (***k***) or the number of equipment units of type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas transmission during the year.
>
> $\boldsymbol{N_k}$ is the total number of equipment units of each equipment type (***k***) listed in section 6.1.2 of the API Compendium if the equipment type is used in the natural gas transmission during the year.
>
> $\boldsymbol{EF_{jk}}$ is the emission factor of gas type (***j***) measured in CO_2-e tonnes for each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium as determined under subsection (2), where the equipment is used in the natural gas transmission.
>
> (2) For $\boldsymbol{EF_{jk}}$, the emission factors for a gas type (***j***) as the natural gas or plant condensate passes through the equipment type (***k***) are:
>
> (a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or
>
> (b) as listed in that Compendium for the equipment type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's sections 5 and 6.1.2, and the requirements of Division 2.3.3; or
>
> (c) as listed in that Compendium for the equipment type with emission factors adjusted for variations in the type of equipment material estimated in accordance with the results of published research for the crude oil industry and the principles of section 1.13; or
>
> (d) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors; or
>
> (e) estimated using the engineering calculation approach in accordance with sections 5 and 6.1.2 of the API Compendium.

Method 3 also uses emissions factors for separate components, varying the hours of operation.

3.78 Method 3—natural gas transmission (other than flaring)

(1) Method 3 is:

$$E_j = \sum_k (T_k \times N_k \times EF_{jk})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than flaring) of gas type (***j***) measured in CO_2-e tonnes from the natural gas transmission through the system of pipelines during the year.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component is used in the natural gas transmission.

$\boldsymbol{T_k}$ is the average hours of operation during the year of the components of each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component is used in the natural gas transmission during the year.

$\boldsymbol{N_k}$ is the total number of components of each component type (***k***) listed in section 6.1.3 of the API Compendium if the component type is used in the natural gas transmission during the year.

$\boldsymbol{EF_{jk}}$ is the emission factor of gas type (***j***) measured in CO_2-e tonnes for each component type (***k***) listed in 6.1.3 of the API Compendium as determined under subsection (2), where the component is used in the natural gas transmission.

(2) For $\boldsymbol{EF_{jk}}$, the emission factors for gas type (***j***), as natural gas or plant condensate passes through a component type (***k***), are:

(a) as listed in Table 6-18 in section 6.1.3 of the API Compendium, for the component type; or

(b) as listed in that Compendium for the component type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's Table 6-18 in section 6.1.3, and the requirements of Division 2.3.3; or

(c) as listed in that Compendium for the component type with emission factors adjusted for variations in the type of component material estimated in accordance with the results of published research for the crude oil industry and the principles of section 1.13; or

(d) if the manufacturer of the component supplies component-specific emission factors for the component type—those factors; or

(e) estimated using the engineering calculation approach in accordance with section 6.1.3 of the API Compendium.

The component emissions factors for Methods 2 and 3 are sourced from the American Petroleum Institute (API) Compendium, which provides ways to measure and calculate greenhouse gas emissions in the oil and gas industry. For lack of an alternative, the Australian NGERs utilises the API Compendium for oil and gas emissions factors.

There are considerable differences between components used in North American and Australian (and New Zealand) pipeline facilities. Hence, using Methods 2 and 3 is considered commercially impractical as they would likely result in an *overestimate* of emissions for some components.

This concern has merit. FirstGas, which operates New Zealand's gas transmission pipelines, is currently undertaking an emissions factor validation project, comparing measured emissions to the API Compendium. Initial results from direct measurement of fugitive emissions of more than 18,000 individual components demonstrate that actual emissions were considerably lower than the assumed API emissions factors. New Zealand uses similar asset components to Australia.

The API Compendium also provides what is effectively an average emission for each component. Hence, Methods 2 and 3 also do not easily permit variations to those factors based on actual operation of those components – including whether they are actively leaking, or not leaking, which requires direct detection if not measurement.[1]

[1] Incidentally, leaker/non-leaker component emissions factors are available for upstream oil and gas operations.

Higher order methods needed sooner rather than later

If policy measures are needed, what would be the best way to reduce reliance on ACCU use without unduly disrupting the carbon market and when should any such measures start?

Considering the evidence above, it is important that any reforms to the Safeguard Mechanism take into account the ability of facilities to comply. Reforms that limit or discourage take up of ACCUs should only be considered once higher order methods are in place for all sectors that may be affected by such reforms due to cost, budgeting cycles, economic and regulatory requirements and resource availability.

The Federal Government has appointed an Expert Panel on Atmospheric Measurement of Fugitive Methane Emissions to provide advice on atmospheric methane detection for the coal, oil and gas sectors. Their goal is to advise whether these approaches could enhance Australia's estimation of fugitive methane emissions.

The Panel is not due to report until mid-2027, and this reporting will be in an advisory capacity. Government will need to consider and respond to this advice, with the implication this may not be implemented in any kind of useful way until closer to 2030, which is when the recommendations of this Review are set to take effect. Hence it is very likely that current and future facilities captured under the Safeguard Mechanism may face a stricter scheme, with an increased focus on onsite abatement, without any practical way to achieve this.

Gas transmission facilities are already abating on-site emissions

It is worth recognising that even though gas transmission assets are limited in what fugitive emissions they can measure and report through the Safeguard Mechanism, there are other incentives to reduce on-site emissions, including businesses' own climate targets and emissions reduction commitments.

These can include both process changes and capital investments. In 2024 APGA commissioned Worley[2] to study emissions reduction opportunities for Australia's gas transmission network and provide advice to asset owners on key decarbonisation opportunities. This analysis, published as *Australia's pipeline methane and gas combustion emissions reduction opportunities,* identifies strategies to reduce both fugitive methane and gas combustion emissions, relative to an assumed carbon price to determine best value options.

This analysis revealed some surprising results. For example, contrary to assumptions, the "low hanging fruit" of eliminating gas-actuated valves proved to be one of the costlier options with lower reduction potential relative to other opportunities. Additionally,

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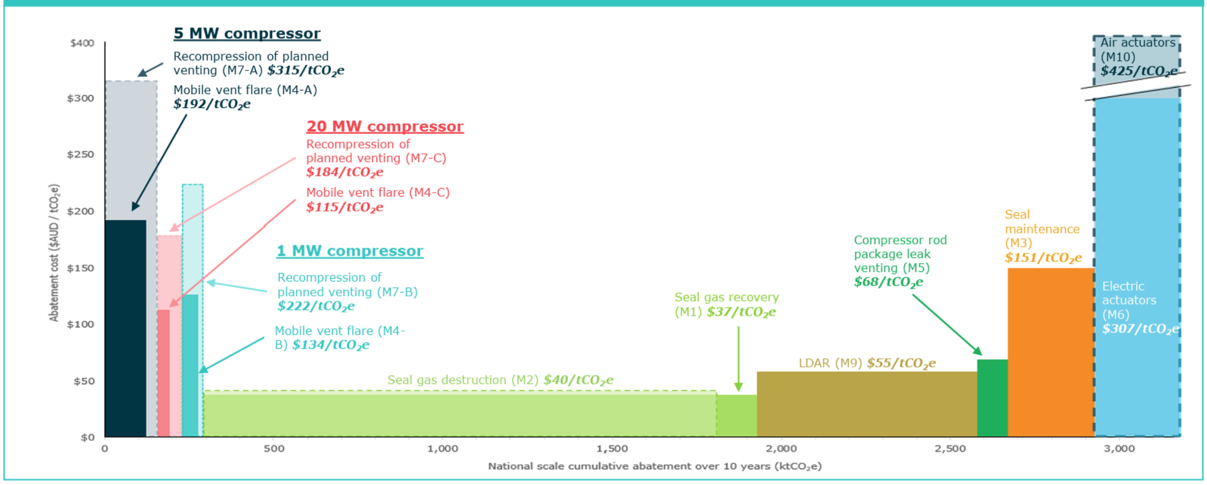
[2] Worley Consulting, 2024, *Australia's pipeline methane and gas combustion emissions reduction opportunities*, https://apga.org.au/en-au/pipeline-methane-and-gas-combustion-emissions-reduction

transitioning compressors to renewable gas is more cost-effective than electrification, particularly when grid connection is required – but this is dependent on a scaled renewable gas industry along with availability of renewable gas certificates backed by a robust certification scheme and, more critically, enabling policy. The latter is currently insufficient.

These opportunities are demonstrated in the below graph, which shows abatement opportunities relative to cost. The largest abatement opportunities are the centrifugal compressor seal gas recovery opportunities and implementing leak detection and repair programs.

The shortlisted methane abatement opportunities in 10 years (2034) on a national scale are shown below



Pipeline facility owners are actively considering what components can be replaced or augmented to reduce emissions, as well as proceeding with investments in fugitive methane emissions detection technologies to support future integration with higher order methods. For example,

- SEA Gas is implementing system optimisations to reduce fuel gas consumption.
- Jemena is exploring projects including electrifying end-of-life compressors and water bath heaters on the Queensland Gas Pipeline, optimising compressor operations and settings, introducing dry-gas seal re-injection, and expanding a trial of capturing and re-injecting vented gas. Jemena's Leakage Survey Program uses Picarro methane detectors mounted on vehicles to detect and quantitively measure emissions from its Jemena Gas Networks distribution operations.
- APA has implemented a range of activities across its assets, including
  - compressor valve and compressor seal upgrades and fuel gas optimisation models to achieve fuel gas reductions, and completed engineering studies and delivery planning for compressor methane recovery;
  - commissioning an electric motor drive compressor station for the Kurri Kurri Lateral Pipeline Project;
  - studying the feasibility of electrifying the Wallumbilla compressor, and is now instead considering biomethane options for that asset.

- Developing an aerial methane survey method using helicopter- and drone-mounted LiDAR methane detectors and using the US EPA Method 21 for converting detected parts per million to volume flow rates, consistent with the methodology that would be applied under OGMP2.0. Through this it has delivered enhanced methane measurements at the Mondarra Gas Storage and Processing Facility, Eastern Goldfields Pipeline System and the South West Queensland Pipeline, the latter of which is a Safeguard Mechanism facility.

- AGIG's decarbonisation activities for its West Australian asset, the Dampier to Bunbury Pipeline, includes pipeline reconfiguration to reduce compressor requirements, progressive replacement of gas engine alternators, and progressive electrification of closed-circuit vapour turbines. Separately, its extensive east coast distribution network has mostly completed a mains replacement program replacing old cast iron mains with polyethylene piping, reducing leaks.

The emissions reduction benefits of many of these activities cannot currently be recognised for the purpose of compliance with the Safeguard Mechanism. While very few gas transmission facilities currently meet the threshold for the scheme, should that change with a review of the scheme threshold, gas transmission facilities may have difficulties complying with their Safeguard obligations if their ability to purchase and surrender ACCUs or SMCs is removed or otherwise restricted.

Expand the scheme with caution

Should the Safeguard Mechanism threshold be lowered and, if so, when?

The current 100,000 tonne CO_2-e threshold covers a significant proportional share of Australia's emissions. Changes to that threshold should consider the additional benefits versus the costs of doing so, which is not limited to the facilities themselves. New facilities means new baseline calculations; where new industries are included, new production variables will also need to be developed, which is not a small task. An increase in the number of facilities will also put pressure on existing resources for climate and sustainability reporting assurance.

APGA considers the current 100,000 tonne CO_2-e to be sufficient. If a change to the Safeguard Mechanism threshold is contemplated, APGA considers that no less than 80,000 tonnes CO_2-e would be an appropriate expansion to the scheme without risking significantly higher scheme costs that would accompany any further reductions. If the threshold is lowered, a reasonable adjustment period should apply, such that the threshold should be lowered in a staggered fashion to 2035.

Conclusion

The effectiveness of the Safeguard Mechanism depends on regulated facilities being able to measure, report and receive recognition for genuine emissions reductions. Gas transmission facilities are already investing in methane detection, operational improvements and lower-emissions technologies, but the current NGER framework does not allow many of these reductions to be demonstrated for Safeguard Mechanism compliance.

DCCEEW should therefore prioritise higher-order methane measurement methods before restricting ACCU use or materially expanding the scheme. If the coverage threshold is lowered, it should move no further than 80,000 tonnes CO_2-e and should be phased in progressively to 2035, allowing sufficient time to establish credible measurement methods and manage the additional regulatory burden.

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