11 April 2025

Submission: 2025 NGERs Amendments

The Australian Pipelines and Gas Association (APGA) represents the owners, operators, designers, constructors and service providers of Australia's pipeline infrastructure. APGA members ensure safe and reliable delivery of over 1,500 PJpa of gas consumed in Australia alongside over 4,500 PJpa of gas for export.

APGA and its members are at the forefront of Australia's renewable gas industry, helping achieve net-zero more quickly and affordably. We support a net zero emission future for Australia by 2050[1] and consider renewable gases to represent a real, technically viable approach to lowest-cost energy decarbonisation in Australia. APGA sees renewable gases such as hydrogen and biomethane playing a critical role in decarbonising gas use for both wholesale and retail customers.[2]

APGA welcomes the opportunity to contribute to the Department of Climate Change, Energy, the Environment and Water's (DCCEEW) consultation on 2025 amendments to the National Greenhouse and Energy Reporting scheme (NGERs). APGA commends the work of the National Inventory Systems and International Reporting Branch in DCCEEW in collaborating with industry on developing these amendments.

Market-based reporting of emissions from consumption of biomethane and hydrogen

APGA has worked closely with DCCEEW on developing the market based method for renewable gases in shared infrastructure. As a result of this work APGA strongly supports the proposed method in all but two aspects, detailed below. While these issues are important, APGA does not consider them to be so significant as to warrant a delay to the introduction the method from 1 July 2025.

Certificate vintaging

DCCEW's approach been determined in line with the same year reported-same year occurred principle of NGERs, effectively allowing 4 and 16 months to acquire and retire certificates.

This may result in consequential market imbalances. Delays in producers registering a product in May/June, or where operators intend to store gas, may result in a situation where older certificates would be less valuable than newer ones or those created at a specific time

[1] APGA, *Climate Statement*, available at: https://www.apga.org.au/apga-climate-statement
[2] ACIL Allen, 2024, *Renewable Gas Target – Delivering lower cost decarbonisation for gas customers and the Australian economy*, https://apga.org.au/renewable-gas-target

of year. It also does not account for situations where renewable gases may be stored in a pipeline or underground storage facility, potentially for months.

These imbalances could result in lower market participation and investment, where certificated could be ‘aged out’ before they can be used. This has no foreseeable benefit other than to accord with usual practice in the NGERs legislation.

APGA recommends DCCEEW remove the certificate vintaging and temporal link requitement. Alternatively, if vintaging is considered an absolute necessity for the method to be legislated, instead match the certificate vintaging for this method with GreenPower, which allows 39 months for certificate retirement. This also aligns with international certification schemes.

Pipeline loss factors

APGA opposes the proposed pipeline loss factors.. Gas losses are already accounted for and covered by existing unaccounted for gas (UAFG) market-based reconciliation between injections and deliveries.

Under existing gas contracting arrangements, pipeline operators are responsible for replacing UAFG. Customers always receive what they pay for, and UAFG is replaced by the pipeline operator and reported as fugitive (methane) emissions.

Imposing a separate loss factor may result in accidental double purchasing where, for example, gas distributors who buy biomethane along with the accompanying certificates, would then have to pay for the additional 1% "loss factor” biomethane on top of UAFG.

Ideally customers would be allowed to claim the renewable gas they purchase, with residual loses treated as “natural gas” and reported by the infrastructure owners as fugitive emissions. APGA also notes that the GreenPower renewable gas scheme does not impose a loss factor, recognising that pipelines were responsible for procuring unaccounted for gas.

Fugitive emissions from oil and natural gas operations

The current fugitive emissions estimation methods for natural gas transmission in NGERs do not provide a mechanism to permit the reporting of measured emissions, and do not facilitate demonstrating a reduction of emissions. This is relevant for operators with obligations under the Safeguard Mechanism.

The only way to reduce assumed fugitive emissions under these methods is to use fewer components, or have shorter pipelines. These methods cannot recognise leaking vs non-leaking components, or changes in operations such as reducing venting.

The Climate Change Authority recognised this in its 2023 *Review of the National Greenhouse and Energy Reporting legislation*, recommending that higher order estimation methods be established for all fugitive methane emission sources. The Government has agreed with this in principle and is establishing an independent expert advisory panel, and urgently phasing out of Method 1 and review of Method 2 for extraction of coal in open cut coal mining.

While the independent panel is preparing its advice to government, industry needs an interim method to estimate fugitive emissions in a more granular fashion than currently available.

DCCEEW has proposed to make *Method 2 – gas flared during natural gas production*, currently 3.87B Method 2B in the NGERs Measurement Determination, available to natural gas transmission and distribution facilities.

Separately APGA has proposed to make *Method 3 – onshore natural gas production, other than emissions that are vented or flared—wellheads*, currently 3.73C in the NGERs Measurement Determination, available to natural gas transmission and distribution facilities.

Making *Method 2B for gas flared during natural gas production* available to natural gas transmission and distribution facilities

DCCEEW's proposes to establish a mass balance approach for estimating fugitive emissions from gas flaring during transmission and distribution of natural gas.

This uses the section *3.87B Method 2B—Natural gas production mass balance approach (flared methane and carbon dioxide emissions)* method which established a 'higher order' method for estimation. Importantly, this

- Establishes for gas transmission the ability to use direct measurements for emissions (in this case, using of gas chromatographs on a flare stack to measure emissions), and
- Enables the use of engineering calculations to estimate emissions from flaring alongside those direct measurements.

Both of these approaches are currently functionally absent for gas transmission flaring, and hence APGA supports the proposal. However this approach is only useful for flaring, which represents a limited source of emissions for gas transmission and distribution.

APGA Proposal: A *Method 3B* for natural gas transmission and distribution facilities

APGA proposes that DCCEEW establish a Method 3B for natural gas transmission and distribution facilities, using the existing *Method 3 for onshore natural gas production, other than emissions that are vented or flared—wellheads* available to natural gas transmission and distribution facilities.

This will establish a measured 'leaker/non-leaker' differentiation for components in natural gas transmission, referring to established leaker/non leaker factors and enable the use of the leak detection options included in the API Compendium 2021.

This proposed method amendment is detailed in the Appendix.

To discuss any of the above feedback further, please contact me on +61 409 489 814 or crafael@apga.org.au.

Yours sincerely,

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Appendix - Proposed Method 3b – natural gas transmission (other than flaring)

Issue

The current fugitive emissions estimation methods for natural gas transmission in NGERs do not provide a mechanism to permit the reporting of measured emissions, and do not facilitate demonstrating a reduction of emissions. This is relevant for operators with obligations under the Safeguard Mechanism.

The only way to reduce assumed fugitive emissions under these methods is to use fewer components, or have shorter pipelines. These methods cannot recognise leaking vs non-leaking components, or changes in operations such as reducing venting.

The Climate Change Authority recognised this in its 2023 *Review of the National Greenhouse and Energy Reporting legislation*, recommending that higher order estimation methods be established for all fugitive methane emission sources. The Government has agreed with this in principle and is establishing an independent expert advisory panel, and urgently phasing out of Method 1 and review of Method 2 for extraction of coal in open cut coal mining.

While the independent panel is preparing its advice to government, industry needs an interim method to estimate fugitive emissions in a more granular fashion than currently available.

Proposal

APGA proposes that DCCEEW make *Method 3 for onshore natural gas production, other than emissions that are vented or flared—wellheads* available to natural gas transmission and distribution facilities, as a Method 3B.

This will establish a measured 'leaker/non-leaker' differentiation for components in natural gas transmission, referring to established leaker/non leaker factors and enable the use of the leak detection options included in the API Compendium 2021.

Proposed Method 3b – natural gas transmission (other than flaring)

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij} / SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (*j*), being methane or carbon dioxide, from the onshore natural gas production during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (*j*), being methane or carbon dioxide, measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (*k*), if the component type is used in the onshore natural gas production during the year.

EF_{ijk} is the emission factor of gas type (*j*), being methane or carbon dioxide, measured in tonnes of CO_2-e per component-hour for each component type (*k*) as determined under subsection (2) or (3), if the component is used in the onshore natural gas production during the year.

Note: Consistent with subsection 3.41(2), emissions associated with any components included in this definition should not be counted under this section if those emissions are also counted as component emissions under another section within this Part.

N_{ik} is the total number of components of each component type (*k*) if the component type is used in the onshore natural gas production during the year.

T_{ik} is:

(a) if subsection (2) applies—the average hours of operation during the year of the component of each component type (*k*), if the component is used in the onshore natural gas production;

(b) if subsection (3) applies—an engineering estimate of the number of hours in the year the component type (*k*) was operational as a leaker or non leaker based on the best available data and subsection (4).

S_{ij} is the measured share of gas type (*j*), being methane or carbon dioxide, in the unprocessed gas (*i*), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (*j*) in the unprocessed gas (*i*), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

Where:

(3) If an LDAR program has been carried out at the facility in relation to onshore natural gas production components in accordance with subsection (4) and this subsection elected for all components under this method, ***EF**$_{ijk}$*, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the **following table** specifies the emission factor for methane (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item; and

(b) column 4 of an item in the **following table** specifies the emission factor for carbon dioxide (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item

[refer to leaker/non-leaker factors in Table 7-28 of the API Compendium 2021.]

Value-add of additional method

The current Methods 2 and 3 in the NGER Measurement Determination allow for asset specific emission factors from the API Compendium, and there is some scope to fine tune emissions reporting via increased granularity of asset classification and matching to favourable emission factors.

However this process introduces similar limitations to Method 1 in that it can only be progressed to the extent allowed for by the type and count of assets themselves. Once the process of matching asset to factor is complete and the lowest possible emission factor selection has been made, there is no further scope to reduce reported emissions. The Methods do not allow for the benefits of an operationally active Leak Detect and Repair (LDAR) program or other active leak management program to be captured.

Allowing for assets to be classified as leaking/non-leaking through this proposed Method provides a clear and direct line from actively assessing and rectifying leaks through to lower reported emissions (and vice versa).

Example 1

Gas Company A maintains an active maintenance program, with quarterly site visits to its above ground assets. Gas levels measured on site at these visits are routinely captured in the works management system. Using the proposed Method 3B Gas Company A can now report this asset as a non-leaker, provided this gas detection process is aligned with the requirements of the legislation. Gas Company A benefits through lower emission reporting.

Example 2

Gas Company B maintains an active LDAR program. The program identifies that a valve is leaking. A work order is raised and the leak is fixed. Using the proposed Method 3B, the existing LDAR program now gives an additional benefit through to lower emissions reporting.

Both of these examples can also be potentially discussed in sustainability reporting as concrete examples of good business practices that are in place that also drive down emissions.