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Department of Climate Change, Energy, the Environment and Water

National Greenhouse and Energy Reporting (NGER) scheme

2025 Public Consultation

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Acknowledgement of Country

We acknowledge the Traditional Owners of Country throughout Australia and recognise their continuing connection to land, waters and culture. We pay our respects to their Elders past and present.

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Overview

The National Greenhouse and Energy Reporting (NGER) scheme

The National Greenhouse and Energy Reporting (NGER) scheme is Australia's national system for reporting greenhouse gas emissions, energy consumption and energy production by Australian corporations.

The NGER scheme is a key data source which supports Australia's international and domestic reporting obligations and informs domestic climate and energy policies. Emissions reported under the NGER scheme underpin the operation of the Safeguard Mechanism.

NGER scheme legislation includes:

- the *National Greenhouse and Energy Reporting Act 2007* (the Act)
- the *National Greenhouse and Energy Reporting Regulations 2008* (the Regulations)
- the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* (the Measurement Determination).

The NGER scheme requires the reporting of greenhouse gas emissions from:

- the combustion of fuel for energy
- the extraction, production, flaring, processing and distribution of fossil fuels, and from carbon capture and storage ('fugitive emissions')
- industrial processes where a mineral, chemical or metal product is formed using a chemical reaction that generates greenhouse gases as a by-product, as well as emissions of hydrofluorocarbons and sulphur hexafluoride resulting from their use by certain industries
- waste disposal – either in landfill, from management of wastewater or from waste incineration.

The NGER scheme defines two reportable *scopes* of emissions (defined in Regulations 2.23 and 2.24). Chapters 1 to 5 of the Measurement Determination provide methods for estimating '**scope 1**' emissions, which are emissions resulting directly from the activities at a facility controlled by the reporting entity. Chapter 7 of the Measurement Determination provides methods to estimate **'scope 2**' emissions, which are indirect emissions of an entity attributable to the consumption of electricity at facilities within the entity's operational control.

Companies are required to register under the NGER scheme if the emissions, energy production or energy consumption from facilities within their operational control exceed specified thresholds.

The NGER scheme allows reporters to choose from a number of available emissions estimation methods to accommodate their individual circumstances. Available methods are ranked by number, with higher numbered methods in-principle providing greater accuracy but requiring more active measurement effort. For a given emissions source, available methods comprise some or all of:

- **Method 1**, which typically involves the use of default emission factors
- **Methods 2 and Method 3**, which involve greater use of facility-specific information

- **Method 4**, which requires direct measurement of emissions.

The requirements of Methods 1 to 3 differ for each source for which they are available. The requirements of Method 4, wherever available, are set out in Part 1.3 of the Measurement Determination, which specifies standards to be met regarding positioning of equipment, frequency of monitoring, and how to determine gas concentrations and flow rates.

The NGER scheme is administered by the Clean Energy Regulator (CER). Further information on NGER reporting is available at the CER's website.

The department is committed to continuous improvement of Australia's national greenhouse gas inventory and the related methods used for estimating emissions. Each year the department reviews and updates the NGER scheme as part of this improvement process and in response to feedback from users and other stakeholders. Every five years the annual update is also informed by the Climate Change Authority's review of the NGER scheme. The Authority's last review of the NGER scheme was delivered in December 2023.

Consultation topics

The department seeks views on two topics.

1. Proposed 2025 amendments to NGER scheme legislation

The consultation paper outlines the following proposed amendments to the Measurement Determination:

- **Renewable fuels**: Introducing market-based reporting of emissions from consumption of biomethane and hydrogen
- **Fugitive emissions from oil and natural gas operations**:
  - Updates to the emissions factors used in Method 1 and Method 2A for gas flared during oil and natural gas operations
  - Making Method 2B for gas flared during natural gas production available to natural gas transmission and distribution facilities
  - Requiring additional reporting of data used to estimate fugitive emissions from flaring during natural gas production
- **Scope 2 emissions from consumption of electricity**:
  - Customary annual update of emission factors
  - Updates to the market-based method including:
    - Requirements for reporters who elect to use the market method to report market-based estimates for all facilities within their controlling corporation's group for which a purchase or acquisition of electricity has occurred in the reporting year, and
    - Amendments to clarify the circumstances for the surrender of renewable electricity certificates

- **Waste**: enabling reporters to account for biosolids diverted to biochar production and an update to the N_2O emission factor for effluent discharged to estuaries.
- Other minor technical updates to improve clarity and operation of the scheme.

The department seeks views on the practical operation and application of the proposed amendments.

This consultation will inform the finalisation of the draft amendment instruments, which will be legislative instruments for the purposes of the *Legislation Act 2003*.

2. NGER scheme forward work program

This consultation paper seeks feedback on the following areas for potential future updates:

- **Review of Method 2 for estimating fugitive methane emissions from open-cut coal mines:** The consultation paper outlines the current Method 2, the background to its review and issues raised to date and invites submissions on issues to be covered by the review.
- **Co-processed liquid fuels:** potential amendments may better enable the reporting of scope 1 emissions from combustion of co-processed liquid fuels; the paper invites submissions on issues to be considered in this work.
- **scope 2 emissions reporting**
    - Renewable Electricity Guarantee of Origin (REGO) certificates may be recognised under the scope-2 market-based method in the future; the paper invites submissions on issues to be considered in this work.
    - To reduce the risk of confusing or misleading claims arising from the interaction between the location-based and market-based methods for reporting scope 2 emissions, the paper invites submissions to inform potential future amendments.

This consultation progresses elements of the Government Response to the 2023 Climate Change Authority review of the NGER scheme. Consistent with that response, the government has also announced the Members and Terms of Reference of the Expert Panel on Atmospheric Measurement Approaches to Fugitive Methane Emissions in Australia. The department continues to progress other elements of the government's response, which will incorporate opportunities for public consultation as appropriate.

Submissions on these topics are invited from all interested stakeholders. Submissions should be lodged electronically via the consultation website.

Submissions may be made publicly available. If you wish for your submission to be kept confidential, this should be clearly indicated in your submission.

1. Proposed 2025 amendments

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

The department proposes to introduce market-based arrangements for reporting scope 1 emissions from the consumption of biomethane and hydrogen (collectively, renewable gas) that has been injected into the natural gas network. This is analogous to the arrangements introduced for renewable liquid fuels in 2024.

What is renewable gas?

For the purposes of these proposed amendments, renewable gas means biomethane and hydrogen. Biomethane and hydrogen are both low scope 1 emissions gases that can be injected into existing gas networks[1].

Biomethane is a biomass-derived, high-methane content gas with nearly identical chemical and physical properties to natural gas. Under the NGER scheme, biomethane has the same technical parameters as natural gas transmitted or distributed in a pipeline, except is assigned a scope 1 carbon dioxide (CO_2) emission factor of zero. This approach is consistent with other biogenic fuel types and reflects the fact that combustion of biomethane releases carbon which was absorbed by its biogenic source materials from the atmosphere during their life[2].

Combustion of hydrogen releases zero physical CO_2 emissions but does release nitrous oxide (N_2O) emissions. Under the NGER scheme, hydrogen is currently considered an energy commodity, not a fuel. To support its inclusion in the proposed market-based reporting arrangements, the department proposes to make hydrogen a reportable fuel type (see Including hydrogen as a reportable fuel type, below).

Under the NGER scheme's existing accounting approach, reporters report the scope 1 emissions from combustion of the gaseous fuel they physically consume. This approach means that when renewable gas is co-mingled with other gases and distributed through shared infrastructure (for example, through shared pipelines), the claim to its consumption and the associated emissions benefit is spread across all users of the infrastructure. Renewable gas purchasers are only able to report consumption of the part share of renewable gas they physically consumed, determined in accordance with the pipeline operator's determination or by sampling and analysing the fuel they physically receive[3].

Stakeholder feedback is that this accounting approach is impeding domestic uptake of renewable gas, especially for some Safeguard Mechanism facilities for whom renewable gas may be one of the

[1] Extending the national gas regulatory framework to hydrogen and renewable gases | energy.gov.au

[2] Under the NGER scheme, facilities reporting emissions from the consumption of fuel report on a scope 1 basis. Emissions associated with the production of fuels, including renewable gaseous fuels, are accounted for in the scope 1 emissions reporting of the fuel producer. The NGER scheme is not a lifecycle emissions reporting scheme.

[3] See Part 2.6 of the Measurement Determination for existing provisions on reporting consumption of a blend of fossil and biogenic carbon fuels.

only viable decarbonisation options[4]. As such, stakeholders have advocated for more flexible 'market-based' accounting approaches that would enable full and exclusive attribution of the scope 1 emissions benefit from their renewable gas purchases, even if the gas they purchased is distributed through the natural gas network and physically consumed by multiple entities.

The introduction of market-based reporting for renewable gaseous fuels was also a recommendation of the independent Climate Change Authority (CCA) review of the NGER scheme (CCA review), published in December 2023.

Design of the proposed renewable gas market-based arrangements

The department proposes to implement market-based reporting for renewable gas by adding a new section (see Schedule 1, Item 5) to Part 2.6 of the Measurement Determination, which sets out rules for determining the amounts of each kind of fuel that is in a blended fuel. This is the same point at which amendments were made in 2024 to facilitate market-based reporting for renewable liquid fuels.

The proposed new section relies on extending the application of Part 2.6 to cover blended gaseous fuels containing hydrogen, which the department proposes to achieve by amending the definition of a *blended fuel* (see Schedule 1, Item 1).

Mandatory, certificate-backed approach

The proposed new section (see Schedule 1, Item 5) would a provide a market-based approach for determining the amount of a renewable gas in a blended gaseous fuel received from a natural gas network.

This market-based approach will replace the existing sampling-based approach in section 2.67A for the purposes of determining the amount of renewable gas in a blended fuel received from a natural gas network. Reporters will continue to use the rules in section 2.67A to determine the composition of any blended gaseous fuel that is not received from a natural gas network.

The department proposes to implement renewable gas market-based reporting using a certificate-backed approach. The essential feature of this model would be that the completion or retirement of an eligible renewable gas certificate by an NGER scheme reporter, or on their behalf, enables them to fully and exclusively reflect the scope 1 emissions attributes of the renewable gas represented by the certificate in their scope 1 emissions reporting. This would be the case even if the facility does not physically consume all the gas represented by the certificate, because of it having been blended and distributed with natural gas in the broader pipeline gas network. Any gas sourced from the natural gas network that is not supported by the retirement or completion of an eligible renewable gas certificate must be reported as fossil natural gas. Once a certificate is retired or completed, it is

[4] Stakeholder consultations have indicated that the preferred and most cost-effective method of transporting renewable gas to market is via the existing natural gas network rather than through new, segregated infrastructure.

withdrawn from circulation and is unable to be used again, ensuring the attributes of a single unit of renewable gas cannot be reported more than once.

Linking renewable gas certificates into the NGER scheme provides a streamlined way of transferring claims to the scope 1 emissions attributes of renewable gas within shared networks. It also provides assurance to government, the public and NGER scheme reporters, that the fuel whose attributes are being reported is indeed renewable gas and improves the integrity and transparency of low emissions claims. It does not mean the scheme would take a lifecycle or full supply chain accounting approach for reporting emissions from renewable gas. The NGER scheme is not a lifecycle emissions reporting scheme. While many low emissions or renewable certifications take a product-based emissions accounting framework that measures and tracks emissions and associated information across the value chain, all this information is not directly relevant to the NGER scheme emissions reporting framework.

The department proposes to recognise two types of certificates under the market-based approach:

- **Product Guarantee of Origin** (PGO) certificates, registered under the Guarantee of Origin (GO) scheme.
- **Renewable Gas Guarantee of Origin** (RGGO) certificates, issued under the GreenPower Renewable Gas Certification (RGC).

Both certificate types could be used to underpin NGER scheme market-based reporting for both biomethane and hydrogen, to the extent that the respective schemes currently cover those products[5]. Each certification scheme has its own eligibility requirements that will remain outside of scope of the NGER scheme arrangements. The NGER scheme market-based arrangements will specify additional requirements that must be met for certificates issued under these schemes to be eligible for use in NGER scheme scope 1 emissions reporting (see Schedule 1, Item 5, and elaborated below).

Temporal link requirement

The department proposes that eligible renewable gas certificates used for market-based reporting must represent renewable gas that was injected into the natural gas network during the reporting year in which its attributes are being reported (see Schedule 1, Item 5, Paragraph 2.67C(5)(a)).

This is intended to ensure a close temporal link between when gas is injected, and when its attributes are reported – helping to maximise the accuracy and comparability of NGER scheme data by ensuring scope 1 emissions reported by a facility for a reporting year represent emissions that the occurred **in that year**, not in an earlier or later period. This is important for maintaining the utility of NGER scheme data in supporting annual products such as the Australian Energy Statistics and National Inventory Report, and for how facilities meet obligations under the Safeguard Mechanism.

[5] The *Future Made in Australia (Guarantee of Origin) Act 2024* has been made, and the department is working on drafting subordinate legislation so the scheme can commence operation in the second half of 2025, commencing with hydrogen. Biomethane is one of the products prioritised for GO scheme expansion and the department will set out timeframes for this in due course. The GreenPower RGC currently covers biomethane and hydrogen produced from renewable energy sources and feedstocks.

While the renewable gas represented by the certificate would need to have been injected into the network within the reporting year, the certificate itself would only need to be retired or completed prior to the submission of the report for the facility for the reporting year (the NGER reporting deadline is 31 Oct each year, four months after the end of the reporting year; see Schedule 1, Item 5, Subsection 2.67C(2), definition of $\boldsymbol{RGC_{RoC}}$).

Practically, if reports are submitted on the due date, reporters will have between 4 months (if renewable gas is injected on the last day of the reporting year) and 16 months (if renewable gas is injected on the first day of the reporting year) to acquire and retire or complete certificates by the NGER reporting due date, as shown in Figure 1.

Figure 1 Temporal link requirement timeline

Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct
NGER reporting year *t*												NGER report due 31 Oct			
Eligible injection period: renewable gas must be injected during reporting year *t* to be reported in reporting year *t*															
Eligible certificate period: certificate representing gas injected during the eligible injection period can be retired or completed any time **prior to the submission of the report** for the reporting year to be included in a NGER report for year reporting year *t*.															

This requirement would only apply to certificates for the purpose of using them to underpin NGER scheme market-based reporting. It would not impact on the underlying certificate lifetime or expiry date, which would continue to be determined in accordance with the rules of the relevant certification scheme.

The information required to demonstrate this requirement will be recorded on eligible renewable gas certificates. For example, the period during which renewable gas was injected into the network will be recorded on a RGGO Retirement Statement. The time and date the product reached the delivery gate will also be listed on PGO certificates.

<u>Reasonable physical link requirement</u>

The department proposes that eligible renewable gas certificates used for market-based reporting must represent renewable gas that could reasonably pass from its injection point into the natural gas network to the NGER facility reporting its attributes (see Schedule 1, Item 5, Paragraph 2.67C(5)(c)). The proposed amendments are **not** intended to facilitate book and claim style reporting of the emissions from consuming renewable gas.

The reasonable physical link requirement balances the need for high integrity, traceable claims to the scope 1 emissions attributes of individual renewable gas consignments, while still providing flexibility in the production, supply and consumption of renewable gas through Australia's interconnected gas networks. It is broadly consistent with the approach taken by other international statutory schemes[6], which the department believes will be important in helping to support the export competitiveness of Australian producers of low emission products for which renewable gas is an input. Producers will increasingly operate in an international trade environment, in which the calculation of embedded emissions will attract substantial scrutiny. If the comparability of proposed NGER scheme

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[6] For example, the European Union (EU) Emissions Trading System, EU Renewable Energy Directive and United Kingdom Renewable Transport Fuel Obligation.

arrangements and those in place overseas is not considered, it could lead to producers potentially failing to meet environmentally focused trade measures, which could hinder their ability to be competitive or enter external markets.

Australia's gas grids largely consist of two segregated systems of interconnected pipeline infrastructure – the East coast gas market and Western Australia gas market. The East coast gas market comprises an interconnected gas grid connecting Australia's eastern, northern and southern states and territories. A similar system of interconnected pipelines operates in Western Australia. Each of these two segregated systems can be treated as being under a separate, closed mass balance for the purposes of NGER scheme market-based reporting. This means NGER scheme facilities who source gas from the East coast gas market can report the scope 1 emissions attributes of renewable gas (as represented by the eligible renewable gas certificates retired or completed by them or on their behalf) supplied into the East coast gas market from *any* injection point but cannot report the scope 1 emissions attributes of renewable gas injected into the Western Australia market (and vice versa).

Eligible renewable gas certificates will record and provide the information required to verify the reasonable physical link between the injection point and NGER scheme facility[7].

Facilities that consume renewable gas 'off-grid', either through direct supply of pure renewable gas by ship, rail or road, or through behind the meter (BTM) consumption, can already exclusively report the full scope 1 emissions benefit of their renewable gas consumption within the existing NGER scheme reporting arrangements. Market-based reporting arrangements are not required in this circumstance. The department does not propose to require NGER facilities that consume renewable gas in this way to underpin their reporting by retiring or completing renewable gas certificates. Doing so would impose additional reporting burden and potentially cost on supply and consumption arrangements that are already supported under the scheme. This does not create a risk of double counting, because:

- users of the market-based reporting arrangements must demonstrate, through the information recorded on the certificates they use to underpin their reporting, that the renewable gas they report having consumed was injected into the natural gas network, which will not have occurred in direct supply scenarios; and
- off-grid consumers of renewable gas must continue to report the gas they physically consume, not the gas represented by any renewable gas certificates they retire or complete.

<u>Biomethane displacement ACCU requirement</u>

There are currently three methods under the Australian carbon credit unit (ACCU) scheme that credit ACCUs to projects that generate abatement by producing biomethane and using it to displace the consumption of natural gas, for example, by injecting biomethane into the natural gas network ('biomethane displacement ACCUs').

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[7] For example, RGGO Retirement Statements include information on the name of the producer and renewable gas project to which the certificates relate, as well as the gas metering point number. PGO certificates will also include the details of the delivery gate for the batch of product covered by the certificate.

If a biomethane producer creates both biomethane displacement ACCUs and renewable gas certificates in respect of a single unit of biomethane, double counting could occur if a facility covered by the Safeguard Mechanism:

- uses the renewable gas certificate under the market-based arrangements to report biomethane consumption (instead of natural gas consumption), and
- also meets their Safeguard obligation by surrendering the associated biomethane displacement ACCU.

In this scenario, the emissions benefit of a single unit biomethane consumption (compared to consuming the equivalent amount of natural gas) is claimed twice.

To control this risk, the department proposes that eligible renewable gas certificates used for market-based reporting must not represent renewable gas in respect of which a biomethane displacement ACCU has been surrendered for the purposes of reducing the net emissions number for a facility with obligations under the Safeguard Mechanism (see Schedule 1, Item 5, Paragraph 2.67C(5)(d)).

This requirement gives biomethane producers the flexibility to create both renewable gas certificates and biomethane displacement ACCUs and to use them in a manner that doesn't lead to double counting. This requirement complements a similar requirement in the GreenPower RGC scheme[8] (currently the only domestic biomethane certification scheme).

Accounting for pipeline losses

Renewable gas certificates represent an amount of renewable gas produced and injected into the network, some of which will be lost as pipeline fugitives as the gas moves through the network to a consumer. The department intends to apply a loss factor to account for these pipeline transport losses (see Schedule 1, Item 5, Subsection 2.67C(2), formula and definition of ***LF***).

Broadly speaking, reporters would be able to determine that the gas they receive from a natural gas network in a reporting year contains an amount of a renewable gas, as represented by an amount of eligible renewable gas certificates, adjusted by the loss factor. Allowing reporters to determine the composition of gas they receive from the grid based only on the amount of renewable gas injected into the grid, with no accounting for losses, risks overestimating the renewable gas component eventually received by a customer.

A similar approach to losses is taken in the NGER scheme's optional scope 2 market-method. While the optional scope 2 market-method itself does not have an explicit loss factor, losses are already accounted for as part of LGC entitlement creation by applying a marginal loss factor to the amount of

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[8] Section 7.5 of the GreenPower RGC sets out that if ACCUs and RGGOs are created in respect of the same activity, they must be "stapled", meaning they must be held together by the same person and transferred together to the same person. A person must not retire any Stapled RGGOs unless it has also cancelled any Equivalent ACCUs prior to submitting a RGGO Retirement Request. Allowing both the ACCU and RGGO to be retired separately would lead to double counting of the emission reduction benefits.

renewable electricity dispatched to the grid[9]. Pipeline transport losses are also accounted for in the biomethane displacement ACCU methods.

Accounting for losses in the proposed market-based reporting arrangements is only for the purposes of estimating the amount of renewable gas received by a facility. It does not change existing, separate arrangements for reporting fugitive emissions under the NGER scheme. Renewable gas consumers will **not** be required to report fugitive emissions from pipeline losses of renewable gas they have purchased. Pipeline fugitive emissions will continue to be reported by those entities with operational control of the pipelines.

The **loss factor for biomethane is 1%**, based on an average of the unaccounted-for-gas percentages for each state and territory[10], weighted by each jurisdiction's proportion of Australia's total gas consumption[11]. This factor takes account of the fact that only 37.3% of unaccounted for gas is attributable to leakage[12].

A loss factor of 1% means that 99% of renewable gas injected into the natural gas network, as represented by eligible renewable gas certificates, is not lost during pipeline transport and is therefore able to be reported as having been received and consumed by a facility. Any gas sourced from the natural gas network not covered by the loss-adjusted certificate amount would be reported as natural gas.

The **loss factor for hydrogen is 0.9%**, derived by converting the biomethane loss factor using the conversion factors set out in the 2022 consultancy report *Fugitive Hydrogen Emissions in a Future Hydrogen Economy*, commissioned by the UK Department for Business, Energy and Industrial Strategy. This report provides factors for converting natural gas leakage rates to hydrogen leakage rates, on a volumetric, mass and energy basis, under both laminar and turbulent flow regimes[13].

Loss factors for both biomethane and hydrogen in the initial market-based reporting arrangements will be subject to ongoing review and could be updated considering new evidence as part of the NGER scheme's continuous improvement program.

New matters to be identified for fuel combustion sources and relevant industrial processes sources

To support the proposed amendments, the department proposes to specify new reportable items in Schedule 4 of the Measurement Determination (Matters to be identified in relation to sources) in

[9] https://cer.gov.au/schemes/renewable-energy-target/large-scale-renewable-energy-target/large-scale-generation-certificates/calculate-large-scale-generation-certificate-entitlements

[10] See section 3.81 *Method 1 – natural gas distribution* in the Measurement Determination.

[11] See Table C of the Australian Energy Statistics.

[12] In addition to leakage, other potential reasons for unaccounted for gas include meter inaccuracies, use of gas within the system itself, theft of gas, variations in temperature and pressure, and differences in billing cycles and accounting procedures between companies delivering and receiving gas.

[13] The hydrogen loss factor has been derived by converting on an energy leakage basis and assuming turbulent flow.

relation to fuel combustion sources (see Schedule 1, Item 43). The proposed items would provide greater visibility over the use of the proposed new market-based reporting arrangements by requiring reporters who make use of these provisions to identify the eligible renewable gas certificates, and the amount of renewable gas represented by those certificates, used to underpin their reporting.

The proposed new market-based reporting arrangements can also be used for the reporting of scope 1 emissions from the consumption of fuel received from the natural gas network that is used as a feedstock in industrial processes (for example, ammonia production and hydrogen production). As such, the department also proposes to specify new reportable items in Schedule 4 of the Measurement Determination (Matters to be identified in relation to sources) in relation to relevant industrial process sources. The proposed new items are subject to further legislative drafting and so are not included in the Exposure Draft. The department expects they will be similar to those proposed for fuel combustions sources.

Including hydrogen as a reportable fuel type

Hydrogen is currently classified in the NGER scheme as an *energy commodity*. To support its inclusion in the market-based reporting arrangements, the department proposes to reclassify hydrogen as a *fuel*. This will be done through associated amendments to the NGER Regulations.

Making hydrogen an NGER scheme fuel type means it must be listed in Part 2 of Schedule 1 of the Measurement Determination, along with an energy content factor and emission factors, in terms of kg CO_2-e/GJ, for scope 1 emissions of CO_2, CH_4 and N_2O released from combustion of hydrogen (see Schedule 1, Item 40). Combustion of hydrogen does not lead to scope 1 emissions of CO_2 or CH_4 but does release N_2O emissions. The department is in the process of undertaking a review of domestic and international literature and research to help inform the setting of an N_2O emission factor for hydrogen in the Measurement Determination. This factor is subject to further development, so is not included in the Exposure Draft. However, without prejudice to the outcomes of the technical review, the department expects the emission N_2O emission factor for hydrogen to be similar to the N_2O emission factor for natural gas transmitted or distributed in a pipeline.

Various other consequential amendments are also required because of hydrogen being reclassified as a fuel. Proposed amendments to Chapter 8 and Schedule 3 are included in the Exposure Draft (see Schedule 1, Items 38 and 42). Consequential amendments to Chapter 6 and Part 7 of Schedule 1 will also be required – these proposed amendments are administrative in nature and are subject to further legislative drafting, so are not included in the Exposure Draft.

B. Fugitive emissions from oil and natural gas operations

Updates to the emissions factors used in Method 1 and Method 2A for gas flared during oil and gas operations

Divisions 3.3.9A to 3.3.9G of the Measurement Determination provide for the estimation of fugitive greenhouse gas emissions from flaring from oil and gas operations. Currently NGER reporters have the option of estimating fugitive emissions from flaring of gas in accordance with Methods 1, 2, 2A, 2B, or 3.

Methods 1 and 2A provide emission factors for CO_2, methane (CH_4), and N_2O to use in the estimation of emissions from gas flared and from crude oil and liquids flared.

As part of its continuous improvement process, the department reviewed the emissions factors and activity data for flaring of gas.

The review identified an unintentional inconsistency between the emission factors across flaring sources in the Measurement Determination and identified a more suitable approach to deriving the existing factors.

The existing factors are sourced from the Methods for Estimating Atmospheric Emissions from E&P Operations published by the E&P Forum in September 1994 (1994 E&P). 1994 E&P provides limited information on how the factors were derived, including on underpinning assumptions (such as assumed gas composition) and data sample size. It also applies an assumed oxidation factor of 95% that is inconsistent with the default oxidation factors of 98% and 99.5% from the 2006 IPCC guidelines (IPCC 2006)[14], which have been adopted under the Paris Agreement for the estimation of national greenhouse gas inventories.

The department has developed revised for CO_2 and CH_4 emission factors using a carbon balance stoichiometry approach. As CO_2 and CH_4 represent 99.3% of emissions from flaring, the department has prioritised reviewing and updating these emission factors. The department also proposes to align the assumed oxidation factor for the N_2O emission factor with the IPCC 2006 default oxidation factor of 98% for gas flaring at oil and gas operations and 99.5% for gas flaring at refineries.

Proposed revised CO_2 emissions factor

The balanced chemical equation of combustion of CH_4 into CO_2 is:

$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$

This assumes that the complete combustion of one molecule of CH_4 results in one molecule of CO_2. The relevant molar masses per gas are calculated by adding together the molar mass of each atom comprising the molecule (as listed in the periodic table of elements[15]):

16.04 g / mol for CH_4, and

44.01 g / mol for CO_2.

The ratio of CO_2 per CH_4 on a mass basis is 44.01 / 16.04 = 2.74.

Therefore, 2.74 times more CO_2 by mass is produced when CH_4 undergoes complete combustion.

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[14] The 2006 IPCC Guidelines, Volume 2, Chapter 4, Equation 4.2.8 states: *flaring destruction efficiency (i.e., fraction of the gas that leaves the flare partially or fully burned). Typically, a value of 0.995 is assumed for flares at refineries and a value 0.98 is assumed for those used at production and processing facilities.*

[15] Australia's Nuclear Science and Technology Organisation, (ANSTO, 2019). Periodic Table of the Elements. https://www.ansto.gov.au/sites/default/files/2019-01/ANSTO_Periodic_Table_Poster_Web.pdf

When natural gas is flared under real world conditions, it is rare that all the CH4 is combusted. The IPCC 2006 provides a default oxidation factor (i.e. 'destruction efficiency') of 0.98[16] to estimate that 2% of the gas does not combust during gas flaring from oil and gas operations excluding oil refining (i.e. this assumes that 98% of the quantity of gas flared is combusted). The IPCC 2006 further provides a default oxidation factor of 0.995 to estimate that 0.5% of gas does not combust during gas flaring from oil refining (i.e. this assumes that 99.5% of the quantity of gas flared at an oil refinery is combusted). As a Party to the UNFCCC and Paris Agreement, Australia is required to estimate emission consistent with the IPCC 2006 guidelines, including by using IPCC default oxidation factors where there are no Australian-specific factors. As the NGER scheme is a primary data source for Australia's annual National Inventory Report to the UNFCCC and Paris Agreement, alignment between NGER scheme methods and Australia's international emissions reporting requirements is important. On this basis, the department's proposed revised factors apply the IPCC 2006 default oxidation factors.

The IPCC 2006 oxidation factor is applied to the rate of CO_2 to remove the unburnt quantity of CH_4:

- 0.98 x 2.74 = 2.69. This means that, for every tonne of gas flared, 98% of the gas is combusted resulting in 2.69 tonnes of CO_2 emitted.
- 0.995 x 2.74 = 2.73. This means that, for every tonne of gas flared at an oil refinery, 99.5% of the gas is combusted resulting in 2.73 tonnes of CO_2 emitted.

Whilst the composition of flare gas is highly variable, Australia's inventory conservatively assumes that flare gas is 100% CH_4 and this assumption has been applied to the revised NGER scheme emission factors. Emission estimates are maximised when flare gas is assumed to be 100% methane because more CO_2 on a mass basis is emitted when methane is combusted, compared with other gases released from a natural gas stream through a flare (e.g. various non-hydrocarbons, some of which do not combust and are not reportable greenhouse gases).

<u>Proposed revised CH_4 emissions factor</u>

The CH_4 emission factor exists to account for the CH_4 that does not combust when gas is flared (i.e. incomplete combustion). As mentioned above in the derivation of the revised CO_2 emissions factor, the IPCC 2006 provides a default oxidation factor (i.e. 'destruction efficiency') of 0.98[17] to estimate that 2% of the gas does not combust during gas flaring from oil and gas operations excluding oil refining (i.e. this assumes that 98% of the quantity of gas flared is combusted). The IPCC 2006 further provides a default oxidation factor of 0.995 to estimate that 0.5% of gas does not combust during gas flaring from oil refining (i.e. this assumes that 99.5% of the quantity of gas flared at an oil refinery is combusted).

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[16] The 2006 IPCC Guidelines, Volume 2, Chapter 4, Equation 4.2.8 states: *flaring destruction efficiency (i.e., fraction of the gas that leaves the flare partially or fully burned). Typically, a value of 0.995 is assumed for flares at refineries and a value 0.98 is assumed for those used at production and processing facilities.*

[17] The 2006 IPCC Guidelines, Volume 2, Chapter 4, Equation 4.2.8 states: *flaring destruction efficiency (i.e., fraction of the gas that leaves the flare partially or fully burned). Typically, a value of 0.995 is assumed for flares at refineries and a value 0.98 is assumed for those used at production and processing facilities.*

This means that, for gas flared at oil and gas operations excluding refineries, the default proportion of CH_4 that is not combusted can be calculated by 1 minus the oxidation factor = 1 – 0.98 = 0.02.

Therefore, the raw emission factor of CH_4 would be 0.02 tonnes per tonne of gas flared.

Paris Agreement reporting requires the use of the IPCC's Fifth Assessment Report Global Warming Potential value (GWP) of 28 to convert CH_4 into carbon dioxide equivalent (CO_2-e) on a 100-year time horizon. To convert the raw emissions factor to CO_2-e, the raw emissions factor is multiplied by the GWP for that gas, 0.02 x 28 = 0.56.

Therefore, the emission factor for methane from gas flared becomes 0.56 tonnes of CH_4 in CO_2-e per tonne of gas flared.

For gas flared at oil refineries, the default proportion of CH_4 that is not combusted can be calculated by 1 minus the oxidation factor = 1 – 0.995 = 0.005. When the raw emissions factor is multiplied by the GWP for that gas, 0.005 x 28 = 0.14.

Therefore, the emission factor for CH_4 from gas flared at oil refineries becomes 0.14 tonnes of CH_4 in CO_2-e per tonne of gas flared.

Proposed revise N_2O emissions factor

The source of the N_2O factor is Table 4.6 of the E&P Forum 1994 report: 0.000081 t N_2O / t gas flared.

The footnote in this table indicates the use of an oxidation factor of 95%, however, Australia's inventory uses the IPCC 2006 default oxidation factor of 98% in relation to N_2O.

Applying the adjusted oxidation factor gives (0.000081 / 95) x 98 = 0.000084 t N_2O / t gas flared.

Paris Agreement reporting requires the use of the IPCC's Fifth Assessment Report GWP of 265 to convert N_2O into carbon dioxide equivalent (CO_2-e) on a 100-year time horizon.

Therefore, the emission factor for N_2O from gas flared becomes 0.022 tonnes of N_2O in CO_2-e per tonne of gas combusted.

Applying the adjusted oxidation factor for gas flared at oil refineries gives (0.000081 / 95) x 99.5 = 0.000085 t N_2O / t gas flared. Therefore, the emission factor for nitrous oxide from gas flared at an oil refinery also becomes 0.022 tonnes of N_2O in CO_2-e per tonne of gas combusted.

The proposed amendments would have the following benefits:

- Improving consistency and accuracy of gas flaring emissions factors across the Measurement Determination, and
- Aligning the NGER scheme with Paris Agreement emissions reporting requirements.

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

As part of the 2024 NGER scheme updates[18], a new method for estimating emissions from flaring of gas at some oil and gas facilities was introduced: section 3.87B Method 2B—Natural gas production mass balance approach (flared methane and carbon dioxide emissions). Method 2B was developed to more accurately estimate emissions from a given facility's natural gas flaring activities, while minimising reported barriers to uptake of higher order methods for this emissions source largely relating to requirements to sample gas composition at the flare point and associated costs.

While the 2024 amendment applied to gas flaring during natural gas production, the mass balance approach is equally applicable to the estimation of fugitive emissions from gas flaring during transmission and distribution of natural gas. The existing Method 2A requires the use of gas chromatographs on the flare stack. It is not always possible to affix and maintain gas chromatographs to flare stacks for technical or safety reasons. Allowing for the use of Method 2B would leverage existing metres and gas composition collection processes to enable a robust engineering approach to estimate emissions from flaring.

Divisions 3.3.9D and 3.3.9G of the Measurement Determination provide for the estimation of fugitive greenhouse gas emissions from flaring from natural gas transmission and distribution. Currently NGER reporters have the option of estimating these emissions in accordance with Methods 1, 2, 2A or 3.

The department proposes to amend these Divisions of the Measurement Determination to allow the use of the above-mentioned Method 2B approach for estimating transmission and distribution flaring sources. The proposal would have the benefit of providing an additional option for reporters to more accurately estimate emissions from a given facility's natural gas flaring activities. The department will continue to explore opportunities for new methods to better capture the impact on emissions of facility-specific flaring activities during natural gas transmission and distribution, including abatement activities.

New matter to be identified (MTBI) for Methods 2, 2A, and 3 for flaring from oil and gas operations

In the context of developing the preceding two proposed amendments, the department also reviewed the additional, related data that facilities provide alongside emissions results calculated using Methods 2, 2A and 3 for flaring of gas from oil and gas operations. Under the NGER scheme, the requirements to report such data are called "matters to be identified" (MTBI) and are listed within Schedule 4 of the NGER Measurement Determination. These specific matters may include inputs from methodological formulae or they may provide additional context around the emissions

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[18] *National Greenhouse and Energy Reporting (Measurement) Amendment (2024 Update) Determination 2024* (version F2024L00823)

results and activities reported. MTBIs provide more context around emissions sources and energy usage, allowing for better analysis and comparison within and across different entities.

MTBIs play an important role in the effective operation of the NGER scheme and by extension Australia's compliance with its UNFCCC and Paris Agreement emission reporting requirements.

Australia's national greenhouse gas inventory uses data reported under the NGER scheme to estimate emissions from gas flaring during oil and gas operations. In accordance with UNFCCC and Paris Agreement reporting rules, data and methods used in Australia's national inventory must be time series consistent from 1989-90 to 2022-23. To incorporate NGER data from higher order methods (i.e. higher than Method 1), achieving time series consistency can require MTBIs from higher order methods to estimate emissions using a Method 1 approach for any given data point. MTBIs also enable the department and the Clean Energy Regulator to assess the accuracy of reported emissions to support compliance with the NGER scheme, including with the Safeguard Mechanism, and UNFCCC and Paris Agreement reporting requirements.

In this context, the department proposes to amend the Measurement Determination to introduce an additional MTBI for Methods 2, 2A and 3 for gas flaring. The additional MTBI would require facilities to report 'the tonnes of flared gas', which includes the total gas stream that moves through the flare stack (both hydrocarbons and inert gases).

This would support national inventory time series consistency and NGER scheme compliance. For example for Method 2 in section 3.87 of the Measurement Determination, only the hydrocarbon component of the total tonnes of gas flared is currently reported as an MTBI (e.g. Schedule 4, Part 2, Source 2U—Offshore natural gas production—flaring, Item 1(a)). This MTBI is not directly comparable to the MTBI collected under Method 1 and Method 2B that report the tonnes of flared gas including all of the fuel type, not just hydrocarbons (e.g. Schedule 4, Part 2, Source 2U—Offshore natural gas production—flaring, Item 1(a) and Schedule 4, Part 2, Source 2U—Offshore natural gas production—flaring, Item 3(a)). The proposed amendment would create consistency in the methods' MTBI, enabling the department to compare within or across facilities using Method 2, 2A, 2B, and 3 in a single year or across Australia's national greenhouse gas inventory time series. It would also assist reporters in being able to analyse the difference between methods and across their own emissions time series for consistency and accuracy when changing methods.

The department understands that information required for this additional proposed MTBI would be readily available to reporters given the hydrocarbon and CO_2 components of flared gas must be calculated as inputs to the higher order methods.

C. Scope 2 emissions from consumption of electricity

The department is proposing amendments to the voluntary Market-Based Method for reporting Scope 2 emissions from the consumption of electricity to improve clarity and transparency for surrender and verification of RECs surrendered against a reporting year.

Proposed Scope 2 emissions factors for the 2024-25 NGER reporting year

The proposed scope 2 location and market-based emissions factors for the 2025-26 reporting year are shown below. These values are updated annually based on on-grid generation and emissions in the preceding reporting year as outlined in section vi above.

Table 1 – Proposed location and market-based emission factors

State, Territory or grid description	Emission factor kg CO_2-e/kWh	Residual mix factor kg CO_2-e/kWh
New South Wales and Australian Capital Territory	0.64	0.81
Victoria	0.78	0.81
Queensland	0.67	0.81
South Australia	0.22	0.81
South West Interconnected System in Western Australia	0.50	0.81
Tasmania	0.20	0.81
Northern Territory	0.56	0.81

Updates to market-based method

The department proposes to update the market-based method to provide clarity around the application of the method within a controlling corporation’s group and surrender of renewable energy certificates.

Where a reporting entity uses the market-based method for a facility within a controlling corporation’s group, the department proposes to make it mandatory to use the market-based method for all facilities within a controlling corporation’s group that reported a location-based scope 2 emissions estimate from the purchase or acquisition of electricity. This is intended to ensure completeness in corporate reporting and avoid potentially misleading or unintended interpretations of corporate emissions data reporting by the Regulator.

Surrender of renewable electricity certificates

The department proposes to update the definitions of REC_{surr} and REC_{onsite} to clarify that these certificates may be surrendered for the reporting year, prior to the submission of the NGER report, but do not necessarily need to be surrendered in the reporting year.

This addresses feedback from NGERS reporters on the surrender deadline suggesting that that surrenders must occur within the reporting year. The proposed amendment clarifies the intent of the method allowing for the practicalities of reporters not knowing during the reporting year how many RECs they will need to surrender to fully offset their electricity consumption.

Additionally, new MTBIs are proposed to allow for the verification of surrendered RECs with reporters required to report the surrender identification codes generated by the CER and accreditation codes for any accredited power stations within a facility.

D. Waste

Introduction of amendments to enable reporters to account for biosolids diverted to biochar production

The department proposes to amend the Measurement Determination to introduce an additional MTBI item, requiring the reporting of the quantity of chemical oxygen demand (COD) in sludge transferred to a biochar production facility 'CODtrb' in both Methods 1 and 2 of the wastewater handling (domestic and commercial) and wastewater handling (industrial).

The proposed amendment would enable reporters to account for the emissions abatement impact of re-directing sewage sludge to be used as a feedstock at biochar production facilities. The proposed amendment would also enable biochar production to be accounted for within the national inventory (as a reduction in emissions from wastewater handling), creating opportunities for biochar abatement methods within the ACCU Scheme.

The proposed amendment would:

- add an additional item in the MTBI Tables in Schedule 4 Part 6 under Source 4B and 4C and 4B;
- amend relevant equations within Methods 1 and 2; and
- add in-text definitions within Methods 1 and 2.

Update to the N_2O emission factor for effluent discharged to estuaries.

The proposed amendment would correct a minor rounding error in the N_2O emissions factor for wastewater effluent discharged to estuaries (EF_{disij}).

The proposed amendment would improve the accuracy of the N_2O emission factor and bring the Measurement Determination into alignment with the default IPCC emission factor and Australia's national greenhouse gas inventory.

2. NGER forward work program

A. Review of Method 2 for estimating fugitive emissions from open cut coal mines

Background

Division 3.2.3 of the Measurement Determination provides for the estimation of 'fugitive' greenhouse gas emissions, including methane, from the extraction of coal from open-cut mining. Currently, NGER reporters have the option of estimating fugitive methane emissions from open-cut mines in accordance with Method 1, 2 or 3. From 1 July 2025, open-cut mines covered by the Safeguard Mechanism that produced more than 10 million tonnes of coal in 2022-23 must use Method 2 or 3. From 1 July 2026, all open-cut mines covered by the Safeguard Mechanism must use Method 2 or 3.

Method 2 estimates fugitive emissions based on the mine-specific methane content of the extracted coal. It is equivalent to the highest (most sophisticated) IPCC method tier. Australia is currently the only country in the world to use methods of this tier to estimate fugitive methane and carbon dioxide emissions from open-cut coal mines in its national inventory.

Method 2 requires the development of a mine-specific model for the in-situ methane in place prior to extraction. This model is used to estimate the fugitive emissions of methane each year when extracting coal from the open-cut mine. Modelling, sampling and analysis must be conducted in accordance with the Australian Coal Industry's Research Program (ACARP) guidelines and relevant Australian Standards. Key components of these methods are set out below, and in further detail in the Clean Energy Regulator's *Estimating emissions and energy coal mining guideline* (cer.gov.au).

- A framework for data collection, including borehole sampling and gas testing of coal and gas bearing strata, which ensures representative and unbiased sampling. Third parties are often used for gas sampling and testing. The "Estimator" (see below) must also be satisfied that the competence and approach taken by those performing the required sampling and testing meets appropriate standards, and that finding documented.

- Guidelines and standards for data analysis and interpretation.

- An approach for estimating gas in near-surface zones characterised by very low gas contents.

- Guidelines on utilising the collected data to produce a model of gas distribution describing the gas content and composition with a defined three-dimensional volume. The process and supporting data for the modelling must also undergo a documented independent peer review by an appropriate professional and demonstrate due diligence.

- Guidelines on estimating the emissions released from the in-situ gas stock as blocks of strata within the mine are extracted for coal production

- Minimum qualifications of persons ("Estimator") who are permitted to estimate emissions from an open-cut mine using the higher order method. It should be evidenced, through the creation and storage of appropriate documentation, that the Estimator (either an individual or a team) used meets the professional and qualification requirements set out in the ACARP guidelines.

- NGER scheme reports are subject to rigorous monitoring and compliance measures administered by the Clean Energy Regulator, including desktop reviews, Greenhouse and energy audits, site visits and data analysis to identify anomalies and reporting errors. Further information on the Regulator's approach to monitoring and compliance is available at *Our compliance approach | Clean Energy Regulator (cer.gov.au)*.

Method 2 also provides that the mine-specific model for the in-situ methane can be adjusted to account for methane captured for combustion, flared, vented or transferred off site.

Review of Method 2

The Climate Change Authority's (CCA) review of the NGER scheme (CCA review), published in December 2023, recommended Method 2 sampling requirements and standards be reviewed (Recommendation 17). The government's response committed to review Method 2 to ensure the method remains fit for purpose and based on the best available science, technologies and practices. Noting the complexity of the method, the department seeks views on areas of concern and opportunities for improvement that could be considered in the scope of the review. To date, stakeholders have proposed the following potential areas for consideration:

- Whether the requirement for a minimum of 3 boreholes in each gas domain insufficient for quantifying the spatial continuity of properties in two or three dimensions.
- Whether the requirement for the gas distribution model to extend to 20m below the final pit floor is sufficient. Gas may migrate from depths extending far beyond 20 m below the pit floor due to natural faults and fractures, or as a result of blasting and/or unloading due to extensive removal of overburden.
- Whether procedures for ensuring that sampling is unbiased and representative could be improved:
    - Whether sample bias analysis should be conducted using statistical methods (the ACARP guidelines state using "expert judgement").
    - Potential bias may be introduced when the required peer review can be undertaken by an employee of the same company.
    - Sampling and model development could be undertaken by an entity independent from the operator to avoid bias.
- Whether the ACARP guidelines should address the following potential contributions of gas:
    - Methane production in the water management ponds and mine water outflows.
    - Methane production or spontaneous combustion from coal waste and other sediments.
    - Emissions from non-coal strata.

- Lateral gas movement into the pit from the horizontal extension of the coal seams outside the mined area and potentially beyond the mine boundary.

- The potential for leakage during gas sampling and the difficulty of minimising air contamination of the samples.
- The extent to which the ACARP guidelines appropriately reflect the documented complexity of Hunter Coalfield, where there can be small- and large-scale faulting, dykes, deeply weathered zones and high gas zones.
- Whether additional guidance is required on Method 2 provisions to account for methane captured on-site, prior to extraction of coal, for combustion, flaring, venting or transfer off site.

Submissions may include commentary on these areas as well as any other areas stakeholders would like to raise regarding Method 2. The insights gained from this preliminary consultation will inform the scope and timing of the review.

B. Co-processed liquid fuels

In July 2024, the government introduced market-based arrangements for reporting scope 1 emissions from the combustion of renewable liquid fuels[19] after they have been co-mingled with their fossil fuel equivalents and supplied through shared infrastructure.

During consultation on the 2024 amendments, some stakeholders advocated for additional amendments to enable reporters to better reflect the lower emissions benefits of consuming co-processed liquid fuels in their NGER scheme reports.

Co-processed fuels are distinct from blended fuels. Blended fuels are typically produced by blending or mixing two or more neat, separately produced fuels to a desired ratio. Co-processed fuels are produced by simultaneously processing fossil and biomass-derived feedstocks in the same refinery to produce a single finished fuel product[20]. A potential advantage of co-processing is that it can leverage existing refinery infrastructure, instead of requiring new, dedicated infrastructure to produce 100% renewable fuel. Typically, only minor or moderate modifications are required to introduce alternative feedstocks into existing refinery infrastructure.

The department is considering what amendments are required to better enable the reporting of scope 1 emissions from combustion of co-processed fuels in the NGER scheme. This may include

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[19] Under the NGER scheme, renewable liquid fuel means renewable aviation kerosene, renewable diesel or biodiesel.

[20] Under the NGER scheme, biogenic fuel types are assigned a scope 1 carbon dioxide emissions factor of zero, reflecting that combustion of biogenic carbon fuels releases carbon which was absorbed by its biogenic source materials from the atmosphere during their life. Consistent with this accounting practice, the scope 1 carbon dioxide emissions factor for co-processed fuels would be reduced in accordance with the biomass carbon content of the fuel.

consideration of potential opportunities to link the NGER scheme with low carbon liquid fuel certifications prioritised for development under the GO scheme.

The department invites submissions on issues to be considered in this work.

C. Scope 2 emissions

Potential future updates to the Market Based method to incorporate the Renewable Electricity Guarantee of Origin (REGO)

The department is considering how to recognise Renewable Electricity Guarantee of Origin (REGO) under the NGER scheme and would welcome views on incorporating REGO into the voluntary market-based method for a future NGERS update.

The market-based method for Scope 2 electricity consumption currently recognises Large Scale Certificates issued under the Renewable Energy Target legislation, it being the primary certification representative of renewable energy production.

However, with the introduction of the REGO it is expected that both REGO and LGC units will be available concurrently until 2030, at which point REGO will take over from LGCs as the primary market means of reflecting the production and consumption of renewable electricity.

The department invites submissions on issues that should be considered in this work.

Measures to address the potential for claiming emissions benefits of LGCs that have been sold to another reporting entity.

The location and market-based methods for reporting scope 2 emissions each provide important information for understanding Australia’s emissions and incentivising investment in renewable energy. All reporters are required to report using the location-based method, while the market-based method is optional. In the context of the NGER scheme and Australia’s National Greenhouse Accounts, the two methods are distinct and are not compared or aggregated. However, the department recognises that there is potential for confusion or misleading claims if the two methods are inappropriately combined or presented together in contexts outside the NGER scheme, including a risk of double claiming.

For example, it is theoretically possible that a facility could claim the benefits of onsite renewable generation production and consumption using the location-based scope 2 method, while also selling the LGCs associated with the onsite generation to other entities. Those other entities may claim the reduced emissions through their scope 2 market-based estimates. The department is considering amendments to minimise this risk of ‘double claiming’ between schemes, for example by requiring facilities that sell LGCs from onsite renewable generation production and consumption to apply the market-based method in addition to the mandatory location-based method so that they cannot also claim the emissions benefit of LGCs they have on-sold.

The department invites submissions to inform this work.

Annex: Notes on exposure draft clauses

National Greenhouse and Energy Reporting (Measurement) Amendment (2025 Update) Determination 2025		
Section number	**Section name**	**Description**
1.	Name	States the name of the 2025 Measurement Determination update instrument.
2.	Commencement	Provides that amendments would commence on 1 July 2025.
3.	Authority	States that the instrument is made under section 10(3) of the NGER Act.
4.	Schedules	A formal clause which allows the Schedule to amend the Measurement Determination.

Schedule 1 - Amendments		
Item number	**Item name**	**Description**
1.	Section 1.8	Amends the definition of a blended fuel to cover blended gaseous fuels containing hydrogen. A blended gaseous fuel must contain fossil fuel and either or both of biogenic carbon fuel and hydrogen.
2.	Section 1.10 (table Item 4B, column headed "Source of emissions")	Amends the order of wastewater sources in the table in section 1.10 to be consistent with the order of wastewater methods in Part 5.3.
3.	Section 1.10 (table Item 4C, column headed "Source of emissions")	Amends the order of wastewater sources in the table in section 1.10 to be consistent with the order of wastewater methods in Part 5.3.
4.	At the end of section 2.67A	Inserts a note to section 2.67A clarifying that the application of section 2.67A is subject to section 2.67C.
5.	After section 2.67B	Inserts a new section 2.67C providing a market-based approach for determining the amount of renewable gas in a blended fuel received from a natural gas network.

Schedule 1 - Amendments		
Item number	**Item name**	**Description**
6.	Subsection 3.44(2) (table item 1)	Updates existing CO_2, CH_4 and N_2O emissions factors for gas flared from oil or gas exploration and development.
7.	Subsection 3.53(2) (table item 1)	Updates existing CO_2, CH_4 and N_2O emissions factors for gas flared from crude oil production.
8.	Subsection 3.69(2) (table item 1	Updates existing CO_2, CH_4 and N_2O emissions factors for gas flared from crude oil refining.
9.	Subsection 3.86(2) (table item 1)	Updates existing CO_2, CH_4 and N_2O emissions factors for gas flared from natural gas production.
10.	After subparagraph 3.88J(1)(a)(ii)	Inserts a new subsection (iia) to include Method 2B from existing section 3.87B as an additional available method for estimating fugitive CO_2 emissions from natural gas transmission.
11.	Subparagraph 3.88J(1)(b)(ii)	Omits “and” as an editorial correction.
12.	At the end of paragraph 3.88J(1)(b)	Inserts a new subsection (iii) to include Method 2B from existing section 3.87B as an additional available method for estimating fugitive CH_4 emissions from natural gas transmission.
13.	Subsection 3.88J(2)	Renumbers subsection to reflect changes made by item 14.
14.	After subsection 3.88J(1)	Adds a subsection to require that, if Method 2B has been used to estimate emissions of either CH_4or CO_2released from gas flared during natural gas transmission, Method 2B must be used to estimate emissions of both gases.
15.	After subparagraph 3.88T(1)(a)(ii)	Inserts a new subsection (iia) to include Method 2B from existing section 3.87B as an additional available method for estimating fugitive CO_2 emissions from natural gas distribution.
16.	Subparagraph 3.88T(1)(b)(ii)	Omits “and” as an editorial correction.
17.	At the end of paragraph 3.88T(1)(b)	Insert a new subsection (iii) to include Method 2B from existing section 3.87B as an additional available method for estimating fugitive CH_4 emissions from natural gas distribution.

Schedule 1 - Amendments		
Item number	**Item name**	**Description**
18.	Subsection 3.88T(2)	Renumbers subsection to reflect changes made by item 19.
19.	After subsection 3.88T(1)	Adds a subsection to require that, if Method 2B has been used to estimate emissions of either CH_4 or CO_2 released from gas flared during natural gas distribution, Method 2B must be used to estimate emissions of both gases.
20.	Subsection 5.25(5)	Updates the method 1 equation for the estimation of CH_4 generated from domestic wastewater handling to include a term (COD_{trb}) for sludge diverted to biochar production.
21.	Subsection 5.25(5) (after the definition of COD_{trl})	Defines the term COD_{trb}.
22.	Subsection 5.25(5) (definition of COD_{tro})	Updates the definition of COD_{tro}.
23.	Subsection 5.26(2), Step 1	Updates the method 2 equation for the estimation of the ratio CH_4 captured to CH_4 generated from sub-facilities at a domestic wastewater handling to include a term (COD_{trbz}) for sludge diverted to biochar production.
24.	Subsection 5.26(2), Step 1 (after the definition of COD_{trlz})	Defines the term COD_{trbz}.
25.	Subsection 5.26(2), Step 1, definition of COD_{troz}	Updates the definition of COD_{troz}.
26.	Subsection 5.26(2), Step 2	Updates the method 2 equation for the estimation of CH_4 generated from sub-facilities at a domestic wastewater handling where the capture to generation ratio is less than or equal to 1.00 to include a term (COD_{trbz}) for sludge diverted to biochar production.

Schedule 1 - Amendments		
Item number	**Item name**	**Description**
27.	Subsection 5.26(2), Step 2 (after the definition of COD_{trlz})	Defines the term COD_{trbz}.
28.	Subsection 5.31(7), (table item 2, column headed "EF_{disij}")	Updates the N_2O emission factor for effluent discharged to estuaries from 1.026 to 1.041.
29.	Subsection 5.42(5)	Updates the method 1 equation for the estimation of CH_4 generated from industrial wastewater handling to include a term (COD_{trb}) for sludge diverted to biochar production.
30.	Subsection 5.42(5) (after the definition of COD_{trl})	Defines the term COD_{trb}.
31.	Subsection 5.42(5) (definition of COD_{tro})	Updates the definition of COD_{tro}.
32.	After subsection 7.1(2)	Introduces a requirement that where an entity uses a market-based method for a facility in its controlling corporation's group, it must apply the market-method for all facilities in its controlling corporation's group.
33.	Subsection 7.4(1) (definition of REC_{surr})	Updates the definition of REC_{surr} to clarify that REC surrenders are made for the reporting year, not necessarily in the reporting year.
34.	Subsection 7.4(3)	Clarifies the definition of REC_{surr} to ensure that RECs must be surrendered prior to the submission of an entity's NGER report.
35.	Subsection 7.4(4)	Clarifies the meaning of eligible certificates in respect of REC_{onsite} and *JRPP.*
36.	Subsection 8.6(1) (table item 28A)	Editorial correction.

Schedule 1 - Amendments		
Item number	**Item name**	**Description**
37.	Subsection 8.6(1) (table item 30, column headed "Fuel Combusted")	Editorial correction.
38.	Section 8.6 (after table item TBC)	Prescribes the energy content uncertainty and carbon dioxide emission factor uncertainty to be used when reporting emissions from combustion of hydrogen using Method 1. The item number for hydrogen is subject to further legislative drafting, so is not included in the Exposure Draft.
39.	After section 9.19	Provides that amendments made by this instrument apply in relation to reporting for the financial year 2025-26 and later financial years.
40.	Part 2 of Schedule 1, Fuel combustion – gaseous fuels (after table item TBC)	Specifies the energy content factor and carbon dioxide, methane and nitrous oxide scope 1 emission factors for the new fuel type hydrogen The carbon dioxide and methane emission factors are zero. The nitrous oxide emission factor will be non-zero – this factor is subject to further technical development, so is not included in the Exposure Draft. The item number for hydrogen is subject to further legislative drafting, so is not included in the Exposure Draft.
41.	Part 6 of Schedule 1 (Column 2, Emission factor kg CO_2e/kWh)	Updates location-based factors for scope 2 emissions for states and territories.
42.	Part 2 of Schedule 3, Carbon content factors – gaseous fuels (after table item TBC)	Specifies the carbon content for the new fuel type hydrogen, which is zero.
43.	Part 1A of Schedule 4 (table item 1, column headed "Matters to be identified", after paragraph (c))	Specifies new matters to be identified by reporters who use the new section 2.67C to determine the amount of renewable gas in a blended fuel received from a natural gas network.

Schedule 1 - Amendments		
Item number	**Item name**	**Description**
44.	Part 2 of Schedule 4, Source 2D (table item 2, column headed "Matters to be identified", before paragraph (a))	Inserts "the tonnes of flared gas" as an additional matter to be identified under Schedule 4 when using Method 2, 2A or 3 for estimating emissions of CH_4, CO_2 and N_2O from flaring of gas during oil or gas exploration and development.
45.	Part 2 of Schedule 4, Source 2F (table item 4, column headed "Matters to be identified", before paragraph (a))	Inserts "the tonnes of flared gas" as an additional matter to be identified under Schedule 4 when using Method 2, 2A or 3 for estimating emissions of CH_4, CO_2 and N_2O from flaring of gas during crude oil production.
46.	Part 2 of Schedule 4, Source 2H (table item 4, column headed "Matters to be identified", before paragraph (a))	Inserts "the tonnes of flared gas" as an additional matter to be identified under Schedule 4 when using Method 2, 2A or 3 for estimating emissions of CH_4, CO_2 and N_2O from flaring of gas during crude oil refining.
47.	Part 2 of Schedule 4, Source 2T (table item 2, column headed "Matters to be identified", before paragraph (a))	Inserts "the tonnes of flared gas" as an additional matter to be identified under Schedule 4 when using Method 2, 2A or 3 for estimating emissions of CH_4, CO_2 and N_2O from flaring of gas during onshore natural gas production.
48.	Part 2 of Schedule 4, Source 2U (table item 2, column headed "Matters to be identified", before paragraph (a))	Inserts "the tonnes of flared gas" as an additional matter to be identified under Schedule 4 when using Method 2, 2A or 3 for estimating emissions of CH_4, CO_2 and N_2O from flaring of gas during offshore natural gas production.

Schedule 1 - Amendments		
Item number	**Item name**	**Description**
49.	Part 2 of Schedule 4, Source 2W (table item 2, column headed “Matters to be identified”, before paragraph (a))	Inserts “the tonnes of flared gas” as an additional matter to be identified under Schedule 4 when using Method 2, 2A or 3 for estimating emissions of CH_4, CO_2 and N_2O from flaring of gas during natural gas gathering and boosting.
50.	Part 2 of Schedule 4, Source 2Y (table item 2, column headed “Matters to be identified”, before paragraph (a))	Inserts “the tonnes of flared gas” as an additional matter to be identified under Schedule 4 when using Method 2, 2A or 3 for estimating emissions of CH_4, CO_2 and N_2O from flaring of gas during natural gas processing.
51.	Part 2 of Schedule 4, Source 2Z (table item 2, column headed “Matters to be identified”, before paragraph (a))	Inserts “the tonnes of flared gas” as an additional matter to be identified under Schedule 4 when using Method 2, 2A or 3 for estimating emissions of CH_4, CO_2 and N_2O from flaring of gas during natural gas transmission.
52.	Part 2 of Schedule 4, Source 2Z (at the end of the table)	Reflecting items 10 and 12, inserts matters to be identified under Schedule 4 when using Method 2B for estimating emissions of methane and carbon dioxide from flaring of gas during natural gas transmission. When using Method 2B to estimate emissions of methane, specified matters are (a) the tonnes of flared gas, and (b) the tonnes and gigajoules of methane within the flared gas, calculated through a mass balance. When using Method 2B to estimate emissions of carbon dioxide, specified matters are (a) the tonnes of flared crude oil and liquids (hydrocarbon component) within the flared gas, calculated through a mass balance.

Schedule 1 - Amendments		
Item number	**Item name**	**Description**
53.	Part 2 of Schedule 4, Source 2ZB (table item 2, column headed "Matters to be identified", before paragraph (a))	Inserts "the tonnes of flared gas" as an additional matter to be identified under Schedule 4 when using Method 2, 2A or 3 for estimating emissions of CH_4, CO_2 and N_2O from flaring of gas during natural gas storage.
54.	Part 2 of Schedule 4, Source 2ZE (table item 2, column headed "Matters to be identified", before paragraph (a))	Inserts "the tonnes of flared gas" as an additional matter to be identified under Schedule 4 when using Method 2, 2A or 3 for estimating emissions of CH_4, CO_2 and N_2O from flaring of gas during natural gas liquefaction, storage and transfer.
55.	Part 2 of Schedule 4, Source 2ZF (table item 2, column headed "Matters to be identified", before paragraph (a))	Inserts "the tonnes of flared gas" as an additional matter to be identified under Schedule 4 when using Method 2, 2A or 3 for estimating emissions of CH_4, CO_2 and N_2O from flaring of gas during natural gas distribution.
56.	Part 2 of Schedule 4, Source 2ZF (at the end of the table)	Reflecting changes made through items 15 and 17, inserts matters to be identified under Schedule 4 when using Method 2B for estimating emissions of methane and carbon dioxide from flaring of gas during natural gas distribution. When using Method 2B to estimate emissions of methane, specified matters are (a) the tonnes of flared gas, and (b) the tonnes and gigajoules of methane within the flared gas, calculated through a mass balance. When using Method 2B to estimate emissions of carbon dioxide, specified matters are (a) the tonnes of flared crude oil and liquids (hydrocarbon component) within the flared gas, calculated through a mass balance.

Schedule 1 - Amendments		
Item number	**Item name**	**Description**
57.	Part 6 of Schedule 4, Source 4B (table)	Repeals the table.
58.	Part 6 of Schedule 4, Source 4C (table)	Repeals the table.
59.	Part 6 of Schedule 4, at the end of Source 4A	Introduces additional MTBIs for the reporting of the quantity of sludge transferred to a biochar production facility.
60.	Part 7 of Schedule 4 (cell at table item 1, column headed "Matters to be identified")	Introduces new MTBIs for the reporting of RET accreditation codes for accredited power stations within an NGER facility and Surrender ID numbers for $REC_{surr.}$