AEC EMISSIONS REPORTING GUIDE

PREPARED IN COLLABORATION WITH THE UNIVERSITY OF ADELAIDE

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Contents

About the Emissions Reporting Guide

The Emissions Reporting Guide was developed through a partnership between the Australian Energy Council (AEC) and the University of Adelaide. The joint initiative reflects a shared commitment to assisting the energy sector in meeting Australia's evolving climate reporting obligations. Combining industry expertise with academic insight, the guide offers practical support for emissions reporting in line with international and national greenhouse gas emission reporting standards. This Guide is intended to be a living document that will evolve alongside corporate climate disclosures.

Thank you to Siraj Jardine, Chair of the Climate Disclosure Sub-Working Group, all Sub-Working Group Members, AEC Secretariat Rhys Thomas, and University of Adelaide Dr. Tracey Dodd and Research Assistant Vivian Li for their significant contributions to the development of this guide and their leadership in delivering the supporting analysis.

Introduction

This guide is designed to support Australian energy companies in making accurate and comparable greenhouse gas emission disclosures in line with AASB S2 (Climate-related Disclosures).

AASB S2 requires an entity to measure greenhouse gas emissions in accordance with the Greenhouse Gas Protocol (GGP), unless required by a jurisdictional authority or exchange on which it is listed to use a different method. Most reporting entities in the energy industry report under the National Greenhouse and Energy Reporting (NGER) scheme and will opt to use NGER methods to parts of the entity that report under it.

However, discretion on methodological choices exists within the GGP and other schemes, such as the NGER framework. This guide is therefore intended to assist AEC members in applying consistent, transparent, and credible approaches to greenhouse gas emissions measurement and reporting, particularly in areas where discretion or estimation is required.

In developing this Guide, the AEC Climate Disclosure Sub-Working Group agreed to the following overarching principles:

1. **Accuracy and Completeness** – Greenhouse gas measurement and reporting should to the extent practicable avoid double counting or omissions to maintain data integrity.
2. **Transparency and Credibility** – Energy companies should provide clear, verifiable disclosures that uphold public and investor trust, enabling informed decision-making.
3. **Materiality and Specificity** – Greenhouse gas measurement and reporting approaches should apply a materiality-based approach to scope 3 reporting, ensuring detailed disclosure of material emissions while using estimates (e.g., spend-based emissions or pro-rata estimation guided by the NGER definition of incidental emissions) for immaterial emissions.
4. **Comparability and Consistency** – Where possible, energy companies should align reporting methodologies across the energy sector to support benchmarking and stakeholder interpretation of disclosures.
5. **Confidence in the Transition to Net Zero** – Greenhouse gas disclosures should be credible to maintain a social licence for the transition to net-zero by 2050.
6. **Methodological Choices** – Where uncertainty exists – such as in the selection of methodologies or in the absence of complete data – AEC members should apply

conservative assumptions that avoid underestimation of emissions and reinforce the precautionary principle in emissions reporting.

When calculating emissions inventories, energy companies use the most recent emission factors available for scope 1, 2, and 3 at the time of reporting. It is not industry standard to revise reported emissions in arrears when new emission factors are published prior to the next reporting date.

Scope 1

Scope 1 emissions reporting should be in line with the National Greenhouse and Energy Reporting (NGER) scheme requirements. This includes the use of an operational control boundary and the calculation of emissions as per the NGER (Measurement) Determination.

Note: The NGER scheme does not provide for the calculation or reporting of Nitrogen Trifluoride (NF_3), a greenhouse gas commonly used in electronics and photovoltaic cell manufacturing. Energy companies should consider the production of NF_3 emissions in their operations and determine if they should be included in Scope 1 emissions reporting for AASB.

Scope 1 emissions intensity metric

There are many possible emissions intensity metrics an entity may choose to calculate and disclose. A commonly used intensity metric for electricity generators is emissions intensity of generation. If a reporting entity chooses to report on a scope 1 emissions intensity of its operated generation (emissions per unit of generation), as per the NGER boundary, it is recommended to:

- Exclude storage from the calculation – storage is a net consumer of electricity rather than a generator.[1]
- Exclude contracted generation – these are not scope 1 emissions or operated generation.
- Include electricity generation facilities and exclude non-generation facilities (e.g. office facilities). Calculate 'electricity generation facilities' emissions intensity separately from other scope 1 emissions intensities (e.g. gas production).
- Calculate emissions intensity using sent-out electricity as the denominator rather than total generation (as-generated). Sent-out electricity is the electricity that enters the electricity grid, excluding generation consumed on site by the power station. This is industry convention.[2] The use of total generation may be appropriate in some contexts but must be clearly indicated as such if used.

As noted in the introduction, reporting entities may elect to use alternative boundaries and considerations for their emissions intensity metric. These should be used in addition to (not instead of) the NGER boundary for comparability across the industry.

[1] See page 44 of the NGER estimating-emissions-and-energy-electricity-production-and-consumption-guideline.
[2] NGER data is published on the CER website annually as total generation NGER reporting data and registers | Clean Energy Regulator. Similarly, AEMO's Integrated System Plan (ISP) outputs total generation.

Scope 2

Scope 2 emissions calculations and reporting should be in line with NGER rules, regulations, and legislation where the energy company already reports under NGER. This includes the choice of operational control boundary and calculation of emissions as per the NGER Measurement (Determination), as well as considerations of location and market-based reporting.

Whilst the GGP (section 5.6) suggests electricity generation utilities structure direct electricity supply contracts for their electricity consuming activities with their operated generation facilities to avoid double counting between scope 1 and scope 2, this is not required for NGER reporting and is not common practice in the Australian industry. This illustrates a situation where potential double counting of emissions between operational boundaries (scope 1 and scope 2) cannot be avoided.

Since the GGP does not explicitly address electricity storage, the energy industry relies on NGER guidance to calculate scope 2 emissions from this technology. Under NGER, scope 2 emissions from batteries are treated differently to those from pumped hydro:

- Battery scope 2 emissions are based on the difference between the electricity import and export (round-trip losses).[3]
- Pumped hydro storage scope 2 emissions are based on all purchased and acquired electricity consumed at the facility. This includes the total quantity of grid electricity used during the year to pump or to raise water and operating and maintaining the power station.[4]

Scope 3

NGER does not include guidance on scope 3 emissions and the GGP leaves some calculations open to interpretation. This section provides guidance on accounting for scope 3 emissions, including detailed guidance on certain scope 3 categories which have specific considerations for energy companies. For categories that do not have specific considerations for energy companies, general guidance is provided.

Scope 3 category 1 – Purchased goods and services

Due to the generally low materiality of this category for many energy companies, spend-based emissions data is used in the early years of scope 3, category 1 (scope 3.1) reporting. The benefit of using spend-based data is that this can be relatively simple to obtain from financial statements. The downside is that the emissions are of lower accuracy when using spend-based emission factors, and it may not allow for measurement of the impact of suppliers' decarbonisation initiatives. For example, some low-carbon alternatives are more expensive and might therefore increase a company's calculated emissions inventory.

Some data sources for spend-based emission factors include Watershed's CEDA database, Ecoinvent, and Climate Active emission factors. These are not always publicly available and may require subscriptions with databases or the use of consultants who have subscriptions.

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[3] See page 44 of the NGER estimating-emissions-and-energy-electricity-production-and-consumption-guideline.
[4] See Treatment of electricity used to pump or raise water as an auxiliary loss in power stations using hydro | Clean Energy Regulator for more information in a different context.

Scope 3 category 2 – Capital goods

In terms of materiality, there will be varying emissions inventories in scope 3 category 2 (scope 3.2) for energy companies year-on-year. In years during which capital goods associated with major capital projects (e.g. energy project construction, upgrades) are purchased, this inventory may be larger, whereas it could be close to zero in years with no project activity or capitalised maintenance activity.

As an initial estimate, spend-based data may be used for this category, using total life cycle emission factors[5] – these may be available from the sources listed above for scope 3.1, or sourced from international publications.

Transport (e.g. shipping) of capital goods where they are imported from overseas can also be estimated using standard shipping factors.

Scope 3 category 3 – Fuel- and energy-related activities not included in scope 1 or scope 2

National Greenhouse Accounts can be used for most of the required emission factors.

Scope 3 category 3 a – Upstream emissions of purchased fuels

Scope 3 category 3 A (scope 3.3A) is applicable to the end users of fuels, and in the case of gas retailers the retailer of the fuel.

In the electricity generation industry, this will include emissions from producing the gas purchased for combustion in gas turbines (or on-sold to customers), or mining the coal purchased for combustion in coal-fired power stations. Activity data will include the volume of fuel used by each facility (most likely captured in a scope 1 inventory). The emission factors, if not supplier specific, may be found in the National Greenhouse Accounts. These will be the scope 3 emission factors for items like natural gas distributed in a pipeline, diesel oil, or various types of coal.

For gas retailers, this category covers emissions from upstream production, transmission and distribution of gas sold to customers. The emission factor associated with extracting and processing natural gas can be found in the NGA factors. This is the scope 3 factor specific to a state and split by metro and non-metro areas.

In addition to these emissions, companies should also account for the fugitive emissions from the distribution of natural gas (unaccounted for gas, or UAG), which are explicitly excluded from the scope 3 natural gas emission factors. The recommended approach is to follow the method specified in the NGER measurement determination (method 1, section 3.81 in Division 3.3.8). Following the strict definition of scope 3.11 (relating to direct use-phase emissions), these emissions should be reported in scope 3.3A rather than scope 3.11 (Use of Sold Products); however, indirect use-phase emissions are an optional consideration in scope 3.11. As long as the emissions are captured without double counting, the exact category is not important.

Scope 3 category 3 b – Upstream emissions of purchased electricity

Scope 3 category 3 B (scope 3.3B) is applicable to the end users of electricity, steam, heating, and cooling. This captures the average emissions associated with the fuels used to generate

[5] Further consideration will need to be given to life cycle assessment emissions factors when the recycling of solar panels, wind turbines, and other technologies becomes more common.

electricity, like an average electricity generation-specific scope 3.3A upstream fuel factor for the region.

Activity data will include the volume of electricity, heating or cooling used by each facility (most likely captured in a scope 2 inventory). The emission factors, if not supplier specific, may be found in the National Greenhouse Accounts (NGA). For electricity, these will be the scope 3 emission factors per state, territory, or grid, usually displayed alongside the scope 2 emission factors The NGA scope 3 factors also capture transmission and distribution losses, which are typically reported under scope 3.3C. Energy companies should avoid double counting these emissions. NGA reports are issued annually, and the recommendation is to match the version used for NGER reporting in all disclosures for consistency.

Scope 3 category 3 c – Transmission and distribution (T&D) losses

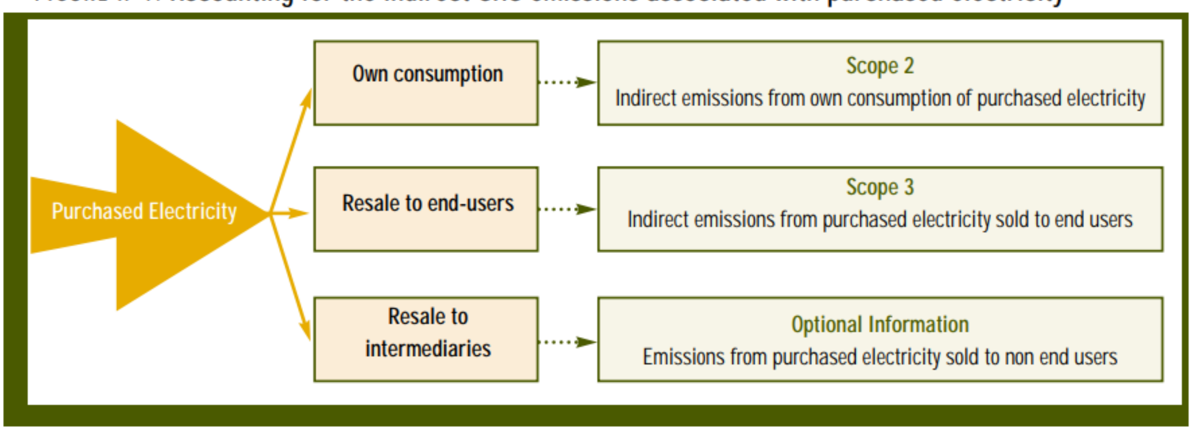
Scope 3 category 3 C (scope 3.3C) is applicable to the end users of electricity, steam, heating, and cooling. This captures the losses through a T&D system. For the Australian electricity sector, this is already captured in the scope 3 emission factors per state, territory, or grid discussed under scope 3.3B. Therefore, these companies do not need to report these emissions separately in scope 3.3C.

Scope 3 category 3 d – Generation of purchased electricity that is sold to end users

Scope 3 category 3 D (scope 3.3D) is applicable to utility companies and energy retailers and particularly relates to companies who purchase wholesale electricity for resale to customers. This is one of the more complex and material categories for electricity retailers in Australia. Uncertainty around the most robust approach exists because of the non-specific guidance in the GGP standards and resources.

In Australia's major energy markets, the National Electricity Market (NEM) and the Wholesale Electricity Market (WEM), electricity is generated and sold (or purchased via PPA and sold) into the wholesale market, to no particular end user. Electricity is then separately purchased from the wholesale market by energy retailers, for on sale to end-users. According to the Greenhouse Gas Protocol Corporate Accounting and Reporting Standard, electricity sold to non-end users does not form part of a scope 3 inventory but may be reported under optional information in the category "Generation of purchased electricity, heat, or steam for re-sale to non-end users". Electricity purchased via PPA and sold into the grid is arguably a sale to a non-end user.

FIGURE A-1. Accounting for the indirect GHG emissions associated with purchased electricity



It is recommended that electricity retailers (including gentailers) use at least the location-based approach and optionally the market-based approach outlined below. The location-based approach represents the emissions associated with the physical flow of electricity, while the market-based approach represents companies' support for renewable electricity generation via the purchase of Renewable Energy Certificates (RECs) like Large Generation Certificates (LGCs), and Renewable Energy Guarantee of Origin certificates (REGOs). As an industry convention, gentailers try to combat double counting by subtracting or "netting off" operated generation sources.

Location-based approach

This Guide's interpretation of the GHG Protocol suggests the most appropriate method for calculating location-based emissions in scope 3.3D is to use the total annual electricity volume retailed to customers per grid, measured at the customer's meter. For convenience, some retailers may elect to use AEMO gross settlement values (i.e. without netting off imports to the grid) measured at a settlement level instead of measurements at the customer meter. This would slightly inflate the emissions inventory because of a loss factor adjustment, but the error introduced is acceptable and conservative.

As an industry convention, gentailers net off annual operated pool generation per state grid from total sales to reduce double counting. Negative net sales per grid are treated as zero. Electricity volumes are then multiplied by the location-based state grid emission factor as published in the NGA factors. The emission factor should represent the full fuel cycle (i.e. scope 2 + scope 3). It is also possible to use the location-based emission factor of an off-grid transmission and distribution network. Do not subtract or net off PPA volumes, or rooftop solar imports into the grid, as the location-based emission factors already include this electricity and associated emissions.

The emissions calculation here for Scope 3.3D is: Location-based emissions = (annual sales to customers per grid – operated generation per grid) x (average full fuel cycle EF per grid).

Market-based approach

An appropriate method for calculating market-based emissions in scope 3.3D is to use the total annual electricity volume retailed to customers, measured at the customer's meter. For convenience, some retailers may elect to use AEMO gross settlement values (i.e. without netting off imports to the grid) measured at a settlement point instead of measurements at the customer meter. This would slightly inflate the emissions inventory because of a loss factor adjustment, but the error introduced is acceptable and conservative.

As an industry convention, gentailers net off annual operated pool generation per state grid from total sales to reduce double counting. Negative net sales per grid are treated as zero. Companies then subtract any RECs (e.g. LGCs) and REGOs voluntarily surrendered and multiply the balance of electricity by the residual mix factor (RMF) as published in the NGA factors. The RMF used should represent the full fuel cycle (i.e. scope 2 + scope 3). Do not subtract or net off PPA electricity volumes apart from LGCs and REGOs, or rooftop solar imports into the grid. Rooftop solar and non-renewable PPA electricity volumes and emissions are already included in the residual mix factor, and renewable PPAs are only considered in LGC and REGO volumes under a market-based approach.

The emissions calculation here for Scope 3.3D is: Market-based emissions = [(annual sales to customers per grid – operated generation per grid) – (RECs and REGOs voluntarily surrendered towards the reporting period)] x (full fuel cycle RMF).

Optional information: emissions from purchased electricity sold to non-end users

Some retailers have PPAs with fossil fuel generators and wish to disclose the emissions associated with these contracts. The emissions and electricity from these generators are already included in the average grid EF and RMF, but energy companies might feel the need to call these contractual arrangements out explicitly. This optional category could also be where retailers declare their energy-only renewable PPAs. In all these PPAs, electricity is purchased from a generator and sold into the wholesale market. The wholesale market is not an end user, and the emissions associated with this electricity will not form part of scope 3 according to the GGP.

The location-based emission factor between the generator and the point at which the electricity enters the wholesale market is identical to the supplier-specific emission factor for the generator. This is because the electricity does not mix with that of other generators before entering the wholesale market.

Under some reporting frameworks, like the Science-Based Target initiative (SBTi), there is no distinction between sales to end users and non-end users. The SBTi refers to "all sold electricity". Retailers wishing to set targets based on an SBTi-style methodology should consider including the emissions and generation from this optional category in their emissions intensity target.

The emissions calculation here is: Optional emissions = (contracted electricity) x (generator-specific EF).

Scope 3 category 4 – Upstream transportation and distribution

Scope 3 category 4 (scope 3.4) refers to vehicle-related transportation and distribution relating to purchased goods from scope 3.1 and transportation and distribution between company facilities. It does not refer to transportation and distribution of gas or electricity. For most energy companies, this will be a small contribution to a scope 3 inventory.

Many energy companies will use spend-based data for scope 3.1. Some of the goods in scope 3.1 will reflect the delivered cost of those goods (i.e. the costs partly relate to the goods and partly relate to the delivery fee). For these goods, data from the Australian Bureau of Statistics (ABS) may be used to approximately disaggregate the spend on purchased goods into goods and freight costs. The freight costs fall into scope 3.4 while the goods fall into scope 3.1. One can assume all deliveries are carried out by truck. Emission factors are available in places like Climate Active or the CEDA database.

Scope 3 category 5 - Waste generated in operations

The easiest first step for this category (scope 3.5) is to use spend-based data and emission factors from sources like Climate Active or the CEDA database. If found to be material, it might be worth switching to activity data like tonnes of waste per category. There are activity-based emission factors available in the same sources.

Scope 3 category 6 - Business travel

For many companies in the energy sector, a suitable place to start for business travel emissions (scope 3.6) is using spend-based data and emission factors from CEDA or Climate Active. There might be some conversion necessary (e.g. using the average $/km for air travel), but these estimates are unlikely to be materially inaccurate in the broader scope 3 inventory. If more accurate activity data (like departure and destination locations) is available, it is recommended to use it.

Scope 3 category 7 – Employee commuting

The most accurate way to estimate these emissions (scope 3.7) is with an employee survey requesting home location, office location, days of travel and modes of transport. However, this can be estimated in its entirety using data from the ABS for typical transportation modes and average commuting distance per transport type, and a company's full time equivalent (FTE) per site.

Scope 3 category 8 – Upstream leased assets

This category (scope 3.8) covers emissions from the operation of leased assets where the reporting company is the lessee, and the emissions are not included in scope 1 and scope 2. An example of this would be if an energy company rents an office space and consumes energy that is not captured under scope 1 and 2. In most instances, the calculation methodology would be very similar to their scope 1 and 2 methodology.

Scope 3 category 9 – Downstream transportation and distribution

This category (scope 3.9) relates to vehicles used to transport, store, and distribute sold products. This does not include electricity losses or fugitive emissions from gas transport. For most energy companies, this category is not relevant.

Scope 3 category 10 - Processing of sold products

This category (scope 3.10) relates to cases where products sold require intermediate processing by downstream companies. For most energy companies, this category will not be relevant.

Scope 3 category 11 – Use of sold products

This category (scope 3.11) relates to the direct use-phase emissions of sold products over their expected lifetime. Scope 3.11 is particularly applicable to energy companies that sell natural gas to end users. There are no emissions from the use of sold electricity.

For this category, companies will have to use activity data in the form of GJ of natural gas sold per state. If it is possible to split sales between metro and non-metro areas, that will be more accurate. If the metro vs non-metro split is not available, this can be estimated based on ABS data, or the highest factor can be used to be conservative.

The emission factor for burning natural gas distributed in a pipeline is available in the NGA factors (scope 1 factor).

In the case of energy companies who sell gas to their own gas-powered generation facilities, the combustion of gas in these facilities should not be included as this will lead to double counting with their Scope 1 inventory. The upstream emissions associated with the fuel used should be included – however this may be accounted for in the S3.3A.

Emission factors and methods relating to decarbonisation by incorporating renewable fuels will likely evolve with updates to the NGER scheme legislation.

Scope 3 category 12 - End-of-life treatment of sold products

Scope 3.12 relates to the scope 1 and scope 2 emissions of waste management companies that occur during disposal or treatment of sold products. Refer to the Greenhouse Gas Protocol for further guidance on this category.

Scope 3 category 13 - Downstream leased assets

Scope 3.13 relates to the operation of assets owned by the reporting company (lessor) and leased to other entities in the reporting year, not included in scope 1 and scope 2. This could be relevant to companies in the energy sector if, for example, they own a generation asset but do not have operational control over the asset.

Scope 3.13 will cover the scope 1 and scope 2 emissions associated with owned assets over which the reporting company does not have operational control. The most material sources of this data will likely be reported under NGER, under a different controlling corporation. The data should be available but might require some inter-company communication to obtain. Calculations should follow the NGER methodology as far as possible.

Scope 3 category 14 – Franchises

Scope 3.14 will not be relevant to most energy companies. If relevant, it will cover the scope 1 and scope 2 emissions associated with franchises, where the reporting company does not have operational control over the franchise.

Scope 3 category 15 – Investments

Scope 3.15 relates to the operation of investments (including equity and debt investments and project finance) in the reporting year, not included in scope 1 or scope 2. This category is mostly applicable to the finance sector, but there might be some applicability to the energy sector as well. The method of calculating emissions from investments will vary depending on the nature of the investment, but it is possible that an NGER methodology will be applicable.

Appendix A – Materiality of emissions

Material for most energy companies	Scope 1
	Scope 3.3
	Scope 3.11 (for gas retailers)
Materiality may vary for different energy companies	Scope 2
	Scope 3.2
	Scope 3.13
	Scope 3.15
Immaterial for most energy companies	Scope 3.1
	Scope 3.4
	Scope 3.5
	Scope 3.6
	Scope 3.7
	Scope 3.8
	Scope 3.9
	Scope 3.10
	Scope 3.11 (for electricity retailers)
	Scope 3.12
	Scope 3.14

Appendix B – Calculation example

Fossil fuel PPA VIC	1,500,000	MWh	1.1	tCO2-e/MWh
Renewable PPA VIC	2,000,000	MWh	0	tCO2-e/MWh
Renewable PPA NSW	500,000	MWh	0	tCO2-e/MWh
Operated generation VIC	4,000,000	MWh	0.5	tCO2-e/MWh
Operated generation NSW	1,000,000	MWh	0.5	tCO2-e/MWh
Rooftop solar VIC	400,000		0	tCO2-e/MWh
Rooftop solar NSW	600,000	MWh	0	tCO2-e/MWh
	10,000,000	MWh		

→ Grid (wholesale market) →

End use customers VIC	3,000,000	MWh	0.86	tCO2-e/MWh
End use customers QLD	2,000,000	MWh	0.88	tCO2-e/MWh
End use customers NSW	1,700,000	MWh	0.73	tCO2-e/MWh
Residual mix factor			0.92	tCO2-e/MWh
	6,700,000	MWh		
LGCs voluntarily surrendered	700,000	LGCs		

Scope 3.3D location-based	2,271,000	tCO2-e
Scope 3.3D market-based	1,840,000	tCO2-e
Optional information	1,650,000	tCO2-e

Location-based approach:

VIC net electricity sales = 3,000 GWh – 4,000 GWh = -1,000 GWh, treat as 0 GWh
NSW net electricity sales = 1,700 GWh – 1,000 GWh = 700 GWh
QLD net electricity sales = 2,000 GWh – 0 GWh = 2,000 GWh

VIC emissions = 0 GWh x 0.86 tCO2-e/MWh = 0 tCO2-e
NSW emissions = 700 GWh x 0.73 tCO2-e/MWh = 511,000 tCO2-e
QLD emissions = 2,000 GWh x 0.88 tCO2-e/MWh = 1,760,000 tCO2-e
Total scope 3.3D = 0 + 511,000 + 1,760,000 = **2,271,000 tCO2-e**

Market-based approach:

VIC net electricity sales = 3,000 GWh – 4,000 GWh = -1,000 GWh, treat as 0 GWh
NSW net electricity sales = 1,700 GWh – 1,000 GWh = 700 GWh
QLD net electricity sales = 2,000 GWh – 0 GWh = 2,000 GWh

Total net electricity sales = 2,700 GWh

LGCs voluntarily surrendered = 700,000 LGCs

Total scope 3.3D = (2,700,000 MWh – 700,000 LGCs) x 0.92 tCO2-e/MWh = **1,840,000 tCO2-e**

Optional information:

VIC fossil fuel PPA = 1,500 GWh x 1.1 tCO2-e/MWh = 1,650,000 tCO2-e
VIC renewable PPA = 2,000 GWh x 0 tCO2-e/MWh = 0 tCO2-e
NSW renewable PPA = 500 GWh x 0 tCO2-e/MWh = 0 tCO2-e
Total optional information = **1,650,000 tCO2-e**