

Greenhouse Gas Mitigation at NSW Coal Mines

Literature Review and Industry Scan

Prepared for NSW Environment Protection Authority

July 2025

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NSW Environment Protection Authority

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Executive Summary

ES1 Background

EMM Consulting Pty Limited (EMM) was commissioned by the NSW Environment Protection Authority (EPA) to undertake a study – involving a literature review and industry scan – relating to the mitigation of greenhouse gas (GHG) emissions in the NSW coal mining sector. The study considered specific mine types, stages and activities, specific gases and emission scopes, existing and emerging mitigation measures, and mine gas utilisation. The findings of the study are provided in this report.

The literature review covered international guidance and studies relating to the mitigation of GHG emissions from coal mines. A qualitative analysis of the mitigation measures identified in the review was also conducted. The industry scan involved a consultation with coal mining companies in NSW to better understand what the coal sector is currently doing to mitigate emissions, to identify the most important factors that influence mine operator decision-making, and to identify potential case studies.

ES2 Literature review

ES2.1 Coal mining processes and emissions in NSW

In the financial year 2021-22¹, the NSW coal mining sector was responsible for 13.9 Mt CO₂-e per year of direct (scope 1) emissions, or 12% of state-wide GHG emissions. Fugitive emissions (around 60%), and fuel combustion emissions associated with mining machinery (around 30%), for active mines accounted for almost all the emissions. Emissions from closed mines (8%) were also significant.

For underground mines, fugitive emissions in NSW have followed a downward trend historically, but are expected to grow during the 2020s, due mainly to increased coal mining, after which they are projected to start decreasing as mining activity slows. By 2040 in NSW, emissions are projected to be around 40% lower than those in 2005. Emissions from surface mines are expected to change little by 2040.

Scope 2 emissions (due to electricity consumption) from all mining in NSW in 2021-22 were 2.9 Mt CO₂-e/year.

ES2.2 Mitigation measures

ES2.2.1 Fugitive methane

For underground mines, the venting of drainage gas or ventilation air methane (VAM) to the atmosphere is undesirable, given the high global warming potential (GWP) of methane.

The main **existing** mitigation options for methane mitigation at underground mines are:

- flaring of drainage gas
- regenerative thermal oxidation (RTO) of VAM.

These convert methane to carbon dioxide (CO₂) and effectively reduces its GWP by around 90%. However, the methane is not used for other purposes (e.g. electricity generation). Gas flaring is used at some coal mines in Australia. RTO has not yet been widely adopted at coal mines in Australia; barriers to implementation identified by industry include low methane concentrations in VAM, safety and cost. The technology involved will vary with the mine type and source type (e.g. drainage gas or VAM; underground mines or surface mines), and each circumstance may be unique.

¹ 2023/24 data were not available at time of writing.

The main **emerging** measure for VAM at active underground mines is regenerative catalytic oxidation (RCO), which has the potential to operate at lower temperatures, higher air flow rates and lower VAM concentrations than RTO. Another emerging technology is methane enrichment using, for example, gas separation, although it is not expected to be commercially available in the near future.

For surface mines, gas drainage is an emerging technology. The barriers to implementation in NSW can include gas reservoir properties making it technically difficult and expensive to extract methane, and difficulties posed by continuously changing mining operations.

For both underground and surface mines, the potential also exists to relocate captured gas from mining seams to neighbouring, gas-undersaturated formations, and trials are currently being considered.

For closed underground mines, existing measures include mine sealing and flooding. Mines going through the decommissioning and closure process have regulatory obligations that include sealing. Flaring is a potential option for treating methane at closed mines, although it is not widely practiced.

ES2.2.2 Diesel combustion

The **existing** measures that can be used to reduce GHG emissions from diesel combustion focus on mine planning, vehicle/equipment procurement to maximise efficiency, and the use of biodiesel. These are coupled with maintenance and training.

With respect to **emerging** measures, a crucial transformation at coal mines will be the electrification of haul trucks and machinery, which will also support automation. However, electrification will require significant investment in infrastructure and hardware, process changes and training. There are also significant uncertainties relating to, for example, battery capacity, cost, charging infrastructure and skills.

An emerging alternative to fossil diesel is renewable diesel, which has similar properties to fossil diesel. Although it is currently in limited supply, renewable diesel could become a transition fuel while other technologies – such as electrification – are being developed. It may also be an option for mines that are unable to adopt electrification or other measures.

ES2.2.3 Electricity use

The third important source of GHG emissions from coal mines is electricity use (scope 2). Almost all coal mines in NSW are connected to the grid. In the future, the scope 2 GHG emissions from coal mining in NSW will be the net result of (i) a reduction in coal production (and energy use), (ii) a probable general increase in mine electrification (and electricity demand), and (iii) the reduction in the emission intensity of grid electricity as the NSW grid decarbonises.

The decarbonisation of the NSW grid should reduce scope 2 emissions from coal mines substantially. In the meantime, it will be possible for mines to reduce their scope 2 emissions through **existing** measures that concentrate on reducing electricity consumption (e.g. the use of more efficient equipment) and/or reducing the emissions intensity of the electricity source. Purchasing electricity generated renewably, rather than from fossil fuels, will reduce the scope 2 emissions from a mine site. Existing mechanisms for this are Power Purchase Agreements (PPAs) for renewable electricity and the surrender of large-scale generation certificates (LGCs). The full breadth of electricity procurement options is an area for future investigation.

An **emerging** option to reduce scope 2 emissions is to incorporate renewable energy sources into mine sites. Examples include wind power, solar power and geothermal power, potentially in combination with energy storage systems. On-site energy storage could also be important in facilitating the wider electrification of mining operations.

ES2.3 Drainage gas utilisation

The productive utilisation of methane in drainage gas can add significant value to a mining operation. The review considered several potential uses for methane, including pipeline gas, chemical feedstock, vehicle fuel, hydrogen production and power generation. The suitability of mine gas for a particular use is primarily dependent on its quality, such as the methane concentration and the stability of supply.

The utilisation of methane for electricity generation at (or near) a mine site is considered to be an existing use. In NSW, drainage gas from coal mines has been used to generate electricity for several decades. All other uses of methane are considered to be emerging, and no examples in Australia were identified in the literature.

ES2.4 Analysis

ES2.4.1 Mitigation measures in project assessments

A brief analysis was conducted of the mitigation measures that have been included in the GHG assessments for a small selection of coal mine projects (as published on the NSW Major Projects website).

For the five underground mines analysed, all proposed pre-drainage and flaring, with two mines also considering the use of RTO. No management of GHG emissions from stockpiles was proposed. Each mine also proposed or considered either on-site or off-site power generation using methane.

For the four open-cut mines analysed, no measures were proposed to address fugitive methane emissions. For diesel combustion, all the mines proposed a number of conventional measures, such as reducing material handling, and optimising haul routes and payloads. Some mines were implementing, or considering, more efficient mine vehicles and equipment. Some mines were also considering the use of alternative fuels. No open-cut mines proposed a major electrification of equipment.

None of the mines analysed proposed measures to reduce emissions from minor GHG sources such as petrol combustion, SF₆, oils/greases or coal oxidation.

At both open-cut and underground mines analysed, the measures for reducing scope 2 emissions focus mainly on general improvements in energy efficiency.

ES2.4.2 Qualitative analysis of mitigation measures

A qualitative assessment of the existing and emerging GHG mitigation measures was conducted. The findings of the analysis are summarised in Table ES1.

Table ES1 **Analysis of mitigation measures**

Emission scope	Emission source	Mine type	Findings
Existing measures			
Scope 1	Fugitive methane (CH ₄)	Underground (active)	Gas drainage is already common at NSW coal mines. To reduce GHG emissions over the mine life, the drainage gas needs to be treated (see below).
			Flaring of drainage gas is already common at NSW coal mines, but still results in CO ₂ emissions. However, the GWP of the emitted gas is greatly reduced.
			For the treatment of VAM, RTO is commercially available. It also results in the conversion of methane to CO ₂ . Barriers to implementation reported by the NSW coal mining industry include low methane concentrations in VAM, safety and cost.
		Surface (active)	Mitigation measures are not well-established for surface mines. However, this is an active area of research.
		Underground (closed)	Standard approaches are passive flooding and sealing. Mines going through the decommissioning and closure process have regulatory obligations that include sealing. There appear to be few incentives to flare emissions from closed mines.
	Diesel combustion	All	Existing measures generally target improving the efficiency of mine operations, and are mostly well-established.
	Other minor sources ^(a)	All	Existing measures are well-established, with few significant barriers to implementation.
Scope 2	Purchased electricity	All	Energy efficiency measures can be readily implemented in principle. Almost all coal mines in NSW are connected to the grid, and the emission intensity of grid electricity is projected to decrease significantly.
Emerging measures			
Scope 1	Fugitive CH ₄	Underground (active)	The main emerging measure for VAM treatment is RCO. It is anticipated that there will be more emphasis on the capture of CH ₄ for productive use (typically electricity generation), primarily through gas drainage.
		Surface (active)	Gas drainage (and treatment) at surface mines is an emerging technology, and there are barriers to implementation in NSW, including gas reservoir properties making it technically difficult and expensive to extract methane, and difficulties posed by continuously changing mining operations. Gas drainage may be feasible at some surface mines in NSW.
		All	Relocate captured gas from mining seams to neighbouring undersaturated formations, and trials are currently being considered.
	Diesel combustion	All	Emerging measures concentrate strongly on mine electrification. It seems likely that the use of on-board batteries will be the preferred option for mining equipment, in combination with a supply of renewable energy for charging. Automation will also probably increase in line with electrification. Renewable diesel could represent an emerging interim measure as other technologies develop. However, a major barrier at the moment is the limited supply.
	Other minor sources ^(a)	All	There are few emerging measures for other minor processes at coal mines. Two promising options for reducing SF ₆ emissions from high-voltage electrical equipment are vacuum circuit breakers and fluorinated gas circuit breakers.
Scope 2	Purchased electricity	All	Emerging measures focus on renewable, on-site electricity generation, in combination with energy storage (probably using batteries).

- (a) Other scope 1 emission sources include the use of petrol, ammonium nitrate fuel oil (ANFO), oils and greases, SF₆ leakage, coal oxidation and vegetation removal. Together, these typically form only a small contribution to total GHG emissions at a coal mine.

ES3 Industry scan

ES3.1 Method

To support the development of the EPA's coal mine Mitigation Guide, in late 2024 and early 2025 the EPA and EMM conducted a consultation with the NSW coal mining industry, referred to here as an 'industry scan'. Coal mining companies and the peak industry body were invited to attend an on-line interview with the EPA and EMM, and/or complete a survey form off-line. In total, interviews with nine mining companies were conducted.

ES3.2 Results

ES3.2.1 Mine characteristics

The industry scan provided information on mine characteristics, including the main scope 1 GHG emission sources and the characteristics of the coal seam and (for underground mines) the ventilation air.

For all active underground mines, VAM was reported as a major GHG source, at between 65% and almost 100% of scope 1 emissions, depending on the mine. Drainage gas, where relevant, was reported as another important source. The reported gas content of coal seams ranged from less than 0.5 m³/t to 20 m³/t. The reported methane concentration of the drained coal seam gas was also variable. For the ventilation air from active underground mines, the reported methane concentration was up to 0.4%.

At active surface mines, the main contributor to emissions was reported as diesel combustion, with a fugitive methane contribution that could be high or low, depending on the mine. The reported gas content of coal seams was generally low compared with underground mines.

Two underground mines in the industry scan were either closed or in the care and maintenance stage. The information provided for these was limited, but for the mines included it indicated that methane emissions would be relatively low.

ES3.2.2 Mitigation for scope 1 emissions: fugitive methane

For the underground mines in the industry scan, the main mitigation measures that were reported as currently implemented or being considered are:

- pre/post drainage with flaring and, in some cases, power generation from drainage gas
- RTO.

One mine reported it had previously implemented RTO, but had ceased operation. Other mines reported that they were either still considering implementation, or considered it to be unfeasible, mainly due to low methane concentrations in ventilation air, safety concerns and, from an economic perspective, a short remaining life of mine.

It was noted by interviewees that RTO has potential safety issues that need to be addressed in Australia. Interviewees reported that to date, risk mitigation has focussed on reducing the likelihood of an accident, but the consequences remain unaddressed. In addition, the application of RTO would be easier if systems could be modular and transferrable between sites.

Although some surface mines were considering drainage, flaring and gas utilisation, these measures had either not yet been implemented, or had been deferred. Open-cut pre-drainage was considered to be an emerging

technology. Identified barriers to drainage included multiple seams of varying thickness, typically shallower depth and lower gas content than underground mines. Interviewees noted that these factors would add to complexity and cost, and make it challenging to achieve feasible, economic gas recovery for emissions reduction. Drainage may also be challenging at open-cut mines due to active workings.

For mitigation of fugitive methane at underground mines that are closed or in care and maintenance, interviewees reported that mitigation currently concentrates on sealing and flooding.

Interviewees stated that funding is required for the introduction of infrastructure (e.g. pipelines) to support gas utilisation.

ES3.2.3 Mitigation for scope 1 emissions: diesel combustion

At underground mines, where diesel combustion is a relatively small contributor to total emissions, the reported mitigation effort is quite limited. However, the use of electric equipment – especially conveyors for transporting coal – is common.

Diesel combustion was reported as a more important consideration at surface mines. Minimising diesel consumption was reported as standard business practice, and typically involves a combination of mine planning, operational efficiencies and driver training. Biodiesel and renewable diesel have not been implemented for a number of reasons, including high cost compared with conventional diesel, the limited supply, and the lack of detailed studies of their effects.

Interviewees reported that some large equipment at surface mines is already electrified (tethered), such as draglines and shovels, but the electrification of haul trucks is an emerging technology. Trolley assist has effectively been rejected due to the changing nature of the mine layout. Few respondents specifically mentioned automation, although one interviewee argued that it may not necessarily result in emissions reduction.

With respect to mine electrification, the following additional comments were made:

- At underground mines the equipment is mostly electrified (both mining equipment and haulage/conveyor equipment). Diesel combustion is therefore minimised/avoided.
- Battery electric and hybrid electric mine vehicles currently have a low technological readiness, but a larger-scale roll-out can be expected from 2035 (possibly earlier for hybrids). Fuel cell mine vehicles have a low technological readiness.
- The larger mining companies have better access to the latest technology, and are able to conduct more trials. There are commercial barriers for small- to mid-tier mining companies.
- Electric haul trucks can use 10 MW of power in 30 minutes, and there is not energy supply to sites to operate them. The electricity supply would need to be augmented.
- There are currently skill shortages in relation to maintaining and operating electric vehicles.

ES3.2.4 Mitigation for scope 1 emissions: other minor sources

The other scope 1 emission sources at coal mines include petrol combustion, blasting, oil and grease use, fugitive SF₆, coal oxidation and vegetation removal. All mines reported these sources have either zero emissions or have a negligible contribution to emissions. Consequently, the information provided was relatively brief. Several mines reported were investigating emerging mitigation measures for these sources, or were in the process of conducting trials.

ES3.2.5 Mitigation for scope 2 emissions

With respect to the mitigation of scope 2 emissions, in general interviewees reported that:

- variable speed motors on, for example, fans, conveyors and pumps, are implemented where possible
- energy efficiency is taken into account for all new major electrical equipment during procurement
- PPAs for renewable energy have been used, or are being considered for commercial viability and practicality. However, barriers include a short remaining life of mine resulting in high cost
- on-site renewable energy has been implemented at some mines, but barriers at other mines include low cost-effectiveness, insufficient resource (e.g. wind) and a lack of available space.

ES3.2.6 Mitigation for scope 3 emissions

Relatively little information was provided on the mitigation of scope 3 emissions. Several mining companies reported they are in the early stages of quantifying their scope 3 emissions. The approaches that were mentioned by interviewees included:

- use of local equipment and materials suppliers, as well as contractors and consultants where practicable to reduced transport emissions
- encouraging direct suppliers to pursue net-zero GHG emissions for their operations
- working with thermal coal customers to looking at technologies such as ammonia and biofuel injection to reduce coal consumption and increase energy output
- supporting industry to develop technology to reduce the GHG emissions intensity of power generation (e.g. boiler efficiency, pellets), steelmaking and shipping
- exploring the potential for carbon capture, utilisation and storage, including sequestering CO₂ in materials (e.g. concrete).

Some of the barriers to addressing scope 3 emissions reported included processes that were outside the operational control of the mines, difficulty in obtaining data for upstream and downstream activities, and a short remaining life of mine.

ES3.2.7 Other issues

No specific opportunities for potential new government funding were raised in the industry scan, although several interviewees expressed an interest, and requested further information on the process to be followed.

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1 Introduction

1.1 Background

In 2023 the NSW Environment Protection Authority (EPA) published its *Climate Change Policy* (NSW EPA 2023a) and its *Climate Change Action Plan 2023–26* (NSW EPA 2023b). These documents outline a comprehensive regulatory approach and a set of actions to address the causes and consequences of climate change in NSW. They support and build upon the NSW Government’s climate change policies and initiatives, including the *Climate Change (Net Zero Future) Act 2023* and the *Net Zero Plan* (NSW DPIE 2020; NSW DPIE 2021a; NSW OECC 2022).

As part of implementing its Climate Change Action Plan, the EPA is intending to produce separate guidance documents for key industries to help them to reduce their greenhouse gas (GHG) emissions. Specifically, Action 17 of the *Climate Change Action Plan 2023–26* states that the EPA will:

Prepare or adopt climate change mitigation guidance for key industry sectors we [EPA] license, including the performance outcomes we [EPA] seek.

The first industry sector to be addressed will be coal mining, and the EPA will initially produce a *Greenhouse Gas Mitigation Guide for NSW Coal Mines* (referred to here as ‘the Mitigation Guide’). The Mitigation Guide will help the proponents of new coal mining projects² to prepare GHG assessments, and licensees of existing coal mines, to prepare Climate Change Mitigation and Adaptation Plans.

1.2 Study objectives and approach

EMM Consulting Pty Limited (EMM) was commissioned by the EPA to undertake a literature review and industry scan, referred to collectively here as ‘the study’, and the findings are presented in this report. The overall objective of the study was to provide technical information for the EPA to consider in the development of the Mitigation Guide.

The literature review covered international guidance and measures relating to the mitigation of GHG emissions from coal mines. The industry scan involved a consultation with coal mining companies in NSW to better understand what the coal sector is currently doing to mitigate emissions, to identify the most important factors that influence mine operator decision-making, and to identify potential case studies.

1.3 Terminology

A range of terminology is used in the literature to refer to different types of coal mine, to the various stages of mining, and to the corresponding GHG emissions. For this study, the terminology has been standardised as far as possible, and in a way that is relevant to the *mitigation* of GHG emissions from NSW coal mines. Appendix A provides a glossary of the terms and abbreviations used in the study.

Box 1: Referring to GHG mitigation measures

For convenience, in this report all mitigation measures, technologies, actions and interventions relating to GHG emissions from coal mines are referred to collectively as *measures*.

² Including proposed extensions or modifications.

1.4 Scope of the study

The topics covered in the scope of this study are shown in Table 1.1.

Table 1.1 **Scope of study**

Topic	Study scope
Mine types and stages	For the purpose of this study, mines were classified as: • active underground mines • active surface (open-cut) mines • closed underground mines. Active mines included those in care and maintenance or in the process of decommissioning. Closed surface mines were not considered to be a significant emissions source. Mitigation measures for ‘post-mining’ emissions, such as those from coal stockpiles, were also addressed.
Mining activities	The study addressed specific activities at coal mines, such as gas drainage, underground mine ventilation, blasting, excavation and hauling.
GHGs and emission scopes	The study considered all relevant GHGs (see section 2.3). The main intent of the study was to address scope 1 and scope 2 emissions (see section 2.4). It also considered scope 3 emissions, although in less detail.
Mitigation measures	The study considered a range of measures to reduce GHG emissions, focussing mainly on: • engineering, design and practical solutions • ‘existing’ and ‘emerging’ measures (see Box 2 below), and the experience of these to date in Australia • emission reductions that could be achieved on-site at coal mines.

Box 2: Existing and emerging measures

In this study a distinction is made between existing and emerging GHG mitigation measures. An important consideration is the level of technological development:

- Existing measures are those that are in the mature stage of technological development and are commercially available. However, it is recognised that there may still be some barriers to implementation.
- Emerging measures are those in either the R&D or demonstration stages of technological development. The barriers to implementation for these measures are likely to be more significant.

The following aspects were outside the scope of the study:

- Reductions in GHG emissions from the coal mining sector associated with declining coal production in the future (i.e. the study was not intended to provide a commentary of the future of the coal mining industry in NSW).
- Regulatory or economic approaches, or broader government policy positions, relating to the reduction of GHG emissions in NSW.
- The pathway for addressing or considering safety issues at coal mines – this is the remit of the NSW Resources Regulator.
- Corporate strategies and frameworks for reducing emissions.

- Detailed consideration of the technological and commercial pathways for emerging measures, which could be an area for further analysis.
- Detailed costs or financial analysis of mitigation.

2 Study context

2.1 Chapter overview

This chapter establishes the context of the study. It considers the state of coal mining in NSW, the GHGs that are relevant to coal mining, and national/NSW legislation, policies and programs for reducing GHG emissions.

2.2 Coal mining in NSW

2.2.1 Coal types and uses

Coal mining is a major contributor to GHG emissions in Australia and NSW. Reducing emissions from coal mining is therefore a crucial – yet challenging – element of emission-reduction strategies in the drive towards net zero emissions.

Australian coal is either lower-rank lignite (brown coal) or higher-rank bituminous (black coal). Brown coal is not mined in NSW, but several regions have large black coal deposits. There are operating mines south of Newcastle near Lake Macquarie, further north-west of Newcastle in the Hunter Valley, in the Gunnedah Basin region of north-western NSW, in the Southern Coalfields to the south of Sydney, and in the Western Coalfields between Lithgow and Mudgee to the west of Sydney. At the time of writing, there are 43 operational coal mines extracting coal in the state, around half of which are surface mines and half are underground mines. There are 59 current Environment Protection Licences (EPLs) for the mining of coal. Some of the mines have ceased extraction and are now only processing coal.

Black coal from NSW is used for either electricity generation, or in the manufacture of steel and cement.

The coal used to generate electricity is called thermal coal. Approximately 85% of coal production in NSW is thermal coal. The thermal coal from NSW also makes up two thirds of Australia's total thermal coal production. The high quality (energy content) of NSW coal means that it is in strong demand overseas, and much of it is exported, mainly to Asia.

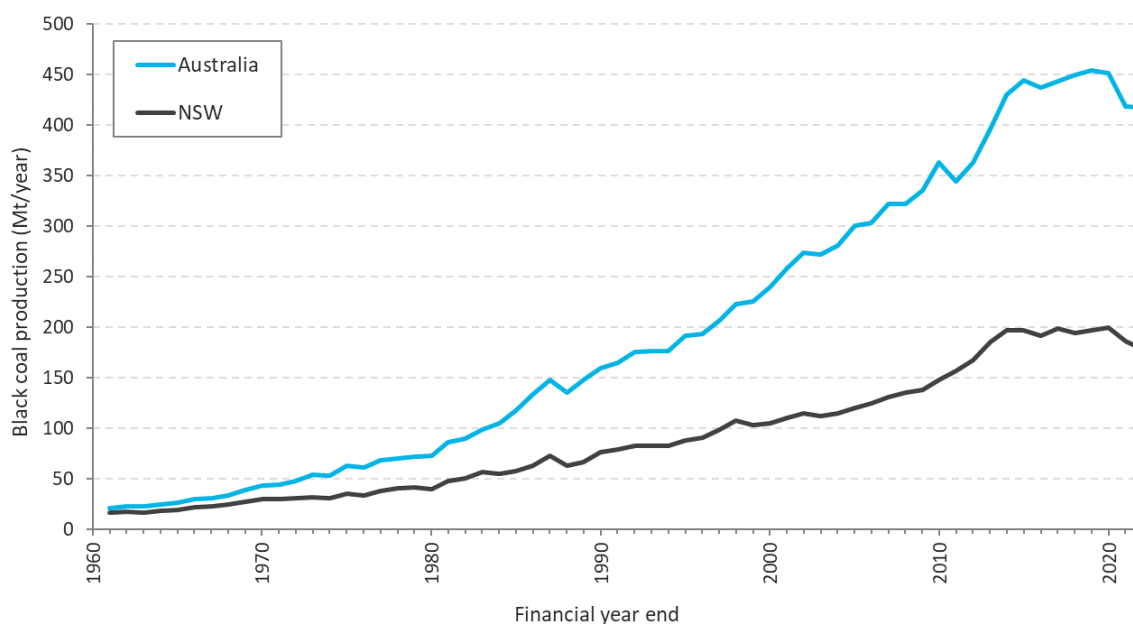
The coal used to make steel and cement is known as metallurgical coal. This coal generally has a higher carbon content than thermal coal, and can be used to produce coke. It is therefore also referred to as coking coal. Metallurgical coal is primarily mined in the Southern Coalfields, and is used to supply the Port Kembla Steelworks, although some of it is also exported to Asia.

2.2.2 Coal production

Figure 2.1 shows black coal production in Australia and NSW between 1960 and 2022. National production increased in most years up to 2015, and then approximately levelled off at around 450 million tonnes (Mt) per year. In recent years, production has been hampered by heavy rainfall causing flooding and storm damage at open-cut pits, as well as damage to port and rail infrastructure. Coal production was also affected by China's restriction on coal imports from Australia until early 2023 (DCCEEW 2023a, 2023b).

In 2021–22, Australia produced 417.2 Mt of black coal, remaining by far Australia's largest contributor to energy production. Since the late 1980s, NSW has produced around 40–45% of Australia's black coal³. In 2021–22 the NSW production was 177.8 Mt. The energy *consumption* in the Australian coal mining sector was 152.2 petajoules (PJ) in 2021–22. This represented a decrease of 1% on the previous year, which was in line with the decrease in coal production (DCCEEW 2023b).

³ Black coal is also produced in Queensland, Western Australia, South Australia, and Tasmania.



Source: DCCEE (2023a)

Figure 2.1 Black coal production in Australia and NSW

2.3 Greenhouse gases

This study deals with the gases addressed under the *National Greenhouse and Energy Reporting Act 2007* (NGER Act), as summarised in Table 2.1. The most important gases in relation to coal mining are carbon dioxide (CO₂) and methane (CH₄)⁴.

Given that the various GHGs have different global warming potentials, it is convenient to express emissions using a common unit. For this purpose, the term ‘carbon dioxide equivalent’ (CO₂-e) has been defined. For a given mass of a specific GHG, CO₂-e signifies the mass of CO₂ which would have the equivalent global warming impact.

Table 2.1 Greenhouse gases and characteristics

Greenhouse gas	Global warming potential (GWP) ^(a)	Atmospheric lifetime (years) ^(a)
Carbon dioxide (CO ₂)	1	N/A ^(b)
Methane (CH ₄)	28	12
Nitrous oxide (N ₂ O)	265	121
Sulfur hexafluoride (SF ₆)	23,500	3,200
Hydrofluorocarbons (HFCs)	Dependent on HFC type	Dependent on HFC type
Perfluorocarbons (PFCs)	Dependent on PFC type	Dependent on PFC type

Notes

(a) From Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5).

(b) No single lifetime can be given for carbon dioxide because it moves throughout the earth system at differing rates.

⁴ The NGER Act does not explicitly cover black carbon, which is present in, for example, diesel engine exhaust. Whilst it is not a GHG, black carbon is a short-lived climate pollutant that contributes to global warming as it absorbs sunlight and reduces the reflectivity of surfaces.

Box 3: The importance of reducing methane emissions

On a mass basis, methane is 28 times more potent in trapping heat than CO₂ when compared over a 100-year period. Over a 20-year period, methane is around 80 times more potent than CO₂. It also has a much shorter atmospheric lifetime (12 years, compared with centuries for CO₂), and oxidises to H₂O and CO₂. A rapid and sustained reduction in methane emissions would therefore help to limit the near-term effects of climate change. According to the International Energy Agency, action on methane will be particularly important in the period to 2030, because sharp cuts in emissions can deliver a net cooling effect within a relatively short period, while the world simultaneously pursues reductions in CO₂ emissions (IEA 2023a). To achieve global net-zero emissions by 2050, the IEA has estimated that methane emissions from fossil fuel operations (globally) would need to fall by around 75% between 2020 and 2030. The IEA estimates that most of this decline will need to come from the rapid deployment of measures and technologies to eliminate avoidable methane emissions (IEA, 2021; IEA 2022).

2.4 Emission scopes

For accounting and reporting purposes, GHG emissions are referred to as 'direct' or 'indirect', and defined according to three 'scopes' (1, 2 and 3). In this study, the activities at coal mines and GHG emission-reduction measures are framed in terms of these emission scopes.

The three scopes are defined as follows:

- Scope 1 relates to direct emissions from sources within the boundary of an organisation, and as a result of the organisation's activities. Scope 1 emissions are determined for the point of release.
- Scope 2 relates to indirect emissions associated with the purchase of electricity, steam, heat or cooling at a site. Scope 2 emissions are generated outside an organisation's boundaries, such as an external power station in the case of electricity. Scope 2 emissions are included in an organisation's emissions inventory because they are a result of the organisation's energy use.
- Scope 3 relates to indirect emissions (other than scope 2 emissions) which occur outside of the boundary of an organisation as a result of actions by the organisation, and are generated in the wider economy. Scope 3 emissions may occur upstream, such as during the extraction and production of the fossil fuels consumed on-site (e.g. diesel in haul trucks), or downstream, such as from the transport of an organisation's product to customers, or the emissions from outsourced activities.

This study is mainly concerned with scope 1 and scope 2 emissions, as defined under the NGER Act, but also considers scope 3 emissions, as defined within Australia's National Greenhouse Accounts for facility reporting (DCCEEW 2023c).

2.5 Legislation and policy

The legislation, policies and programs in Australia and NSW that are relevant to the study, including commitments to GHG emission reductions, are briefly summarised below.

2.5.1 Australia

i Paris Agreement

The Paris Agreement, which the Australian Government has signed, is a legally binding international treaty on climate change. It was adopted by 196 Parties at the 21st United Nations Climate Change Conference (COP21) in Paris, France in December 2015, and entered into force in November 2016. Its overarching goal is to hold the increase in the global average temperature to well below 2°C above pre-industrial levels, and pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels.

ii Climate Change Act 2022 (Commonwealth)

The *Climate Change Act 2022* provides the legislative framework for implementing Australia's net-zero commitments under the Paris Agreement, and sets its GHG emission-reduction targets. Australia has committed to reducing its GHG emissions by 43% below 2005 levels by 2030, and achieving net-zero emissions by 2050.

The Climate Change Act 2022 also introduced a requirement for an annual climate change statement to parliament, supported by independent advice from the Climate Change Authority (CCA).

iii Global Methane Pledge

The Australian Government has also signed the Global Methane Pledge (GMP)⁵. The GMP was launched at the 26th United Nations Climate Change Conference (COP26) by the European Union and the United States. It is a voluntary commitment, with (as of March 2024) 158 countries and the European Union working collectively to reduce global methane emissions across all sectors by at least 30% below 2020 levels by 2030.

iv NGER Act and Scheme

The *National Greenhouse and Energy Reporting Act 2007 (Cwth)* (NGER Act), administered by the Australian Government, establishes a national framework (the NGER Scheme) for corporations to report GHG emissions, energy consumption and energy production. Companies that exceed the NGER Scheme thresholds⁶ of 25,000 tonnes CO₂-e per year for a facility, or 50,000 tonnes CO₂-e per year for a corporation, are required to register and report annually on their scope 1 and scope 2 emissions.

v Safeguard Mechanism

The NGER Act also provides a framework for Australia's highest emitting facilities to manage and report on their GHG emissions. This framework is the Safeguard Mechanism^{7,8}. The Safeguard Mechanism was first legislated in 2014 and has been in place since 2016. It was reformed in 2023 to ensure that the facilities it covers will contribute to meeting Australia's GHG emission-reduction targets.

⁵ <https://www.globalmethanepledge.org/>

⁶ The thresholds are also stated in terms of energy production/consumption.

⁷ <https://www.dcceew.gov.au/climate-change/emissions-reporting/national-greenhouse-energy-reporting-scheme/safeguard-mechanism>

⁸ The Safeguard Mechanism applies to the electricity sector in a different way. It applies a single 'sectoral' baseline across all electricity generators connected to one of Australia's main electricity grids. Individual grid-connected electricity generators are not covered as long as total emissions from grid-connected electricity generators do not exceed the sectoral baseline. See <https://cer.gov.au/schemes/safeguard-mechanism/safeguard-baselines#sectoral-baseline> for more information.

In general terms, the Safeguard Mechanism applies to facilities⁹ with scope 1 emissions¹⁰ of more than 100,000 tonnes of CO₂-e per year. It sets legislated limits — known as baselines — on the GHG emissions of these facilities. These baselines decrease on a trajectory that is consistent with achieving Australia’s GHG emission-reduction targets of 43% below 2005 levels by 2030, and net zero by 2050. The baselines will decrease at 4.9% per year from 2023 to 2030. If a Safeguard facility exceeds its baseline, it must surrender Australian Carbon Credit Units (ACCUs) or Safeguard Mechanism Credits (SMCs) equal to their excess emissions. Facilities with emissions below their baselines may apply to receive SMCs. The Safeguard Mechanism does not introduce a regulatory requirement for on-site GHG mitigation at coal mines.

In the financial year 2022-23, there were 27 coal mines in NSW that were registered as Safeguard Mechanism facilities. GHG emissions from these mines accounted for 57% of NSW’s total GHG emissions reported under the Safeguard Mechanism in that year.

2.5.2 NSW

i NSW Government

The overarching NSW Government legislation and policy documents that are broadly relevant to this study are summarised in Table 2.2. Of these, only the Net Zero Plan refers directly to coal mining.

Table 2.2 Overarching NSW Government legislation and policy

Title	Description	Reference
<i>Environmental Planning and Assessment Act 1979</i>	Establishes the system of environmental planning and assessment for NSW.	-
<i>Climate Change (Net Zero Future) Act 2023</i>	Legislates NSW target reductions in GHG emissions of 50% of 2005 levels by 30 June 2030, 70% of 2005 levels by 30 June 2035, and net zero emissions by 2050.	-
<i>NSW Climate Change Policy Framework</i>	Sets out the NSW Government’s long-term goals of achieving net-zero emissions by 2050, and making NSW more resilient and better adapted to a changing climate.	NSW OEH (2016)
<i>Net Zero Plan Stage 1: 2020–2030</i>	Provides the foundation for NSW’s action on climate change. It outlines the NSW Government’s plan to grow the economy, create jobs and reduce emissions during the 2020s.	NSW DPIE (2020)
<i>Net Zero Plan Stage 1: 2020–2030 Implementation Update</i> <i>Net Zero Plan Implementation Update 2022</i>	These provide updates on the key achievements of NSW Government under the Net Zero Plan, and commit NSW to reducing emissions by 50% below 2005 levels by 2030, and 70% below 2005 levels by 2035.	NSW DPIE (2021a) NSW OECC (2022)

⁹ Grid-connected electricity generators are treated separately.

¹⁰ The threshold applies to actual (gross) emissions from a facility, and does not take into account any offset or displaced emissions.

Title	Description	Reference
Ministerial Statement: <i>Updates regarding Net Zero Plan Stage 1: 2020-2030 and previous Implementation Updates</i>	The policy statement explains that the latest emissions projections show a significant risk that NSW is not on track to meet its 2030 and 2035 targets. The policy statement acknowledges that sectors of the NSW economy will decarbonise at different rates. However, it states that it is the NSW Government's policy that all sectors need to reduce their emissions to meet NSW's legislated targets, and the targets that will be established for 2040 and 2045. The policy statement requires planning decision-makers to consider NSW's emission reduction targets and the <i>Climate Change Act's</i> guiding principles, when examining new developments. The policy statement also requires proponents to consider the EPA's <i>NSW Guide for Large Emitters</i>.	NSW Minister for Climate Change (2024)
<i>NSW Climate Change Adaptation Strategy</i>	Sets out the NSW Government's strategic approach for managing the impacts of climate change on the State.	NSW Government (2022)
<i>NSW Waste and Sustainable Materials Strategy 2041</i>	Sets out how NSW will transition to a circular economy over the next 20 years, including key reforms for reducing GHG emissions from materials (embedded carbon) and the waste sector.	NSW DPIE (2021b)

ii NSW EPA

The EPA is the primary environmental regulator for NSW. Although it has historically regulated some GHGs, the EPA has traditionally focussed on local and regional impacts on health and the environment. It has recently expanded its scope to more explicitly regulate the causes and consequences of climate change in NSW. The key EPA policy documents that are broadly relevant to this study are summarised in Table 2.3.

Table 2.3 Key NSW EPA legislation and policy

Title	Description	Reference
<i>Protection of the Environment Administration Act 1991</i>	Outlines the EPA's statutory objectives and duty to address climate change. Section 6 of the Act outlines the EPA's statutory objectives to protect the environment and human health. The key elements are: - to protect, restore and enhance the quality of the environment in NSW, having regard to the need to maintain ecologically sustainable development - to reduce the risks to human health and prevent the degradation of the environment, including taking action in relation to climate change. Section 9 of the Act imposes a statutory duty on the EPA to develop environmental quality objectives, guidelines and policies to ensure environment protection. This includes protection of the environment from climate change.	-
<i>Protection of the Environment Operations Act 1997</i>	Sets out EPA's statutory powers and regulatory tools, including environment protection licensing. Schedule 1 of the Act sets out the types of activities that need a licence. The EPA is required to consider its statutory objectives (above) when exercising its licensing functions.	-
<i>Climate Change Policy</i>	Supports and builds upon NSW Government's climate change policies and initiatives. The main purpose is to address: - the EPA's statutory objectives to protect, restore and enhance the quality of the environment in NSW, and to reduce the risks to human health and prevent the degradation of the environment - the EPA's statutory duty to develop environmental quality objectives, guidelines and policies to ensure environment protection from climate change.	NSW EPA (2023a)

Title	Description	Reference
<i>Climate Change Action Plan 2023–26</i>	Designed to deliver the Climate Change Policy. The Action Plan sets out: - the specific actions the EPA will take over the three years that it covers - the regulatory action the EPA will consider over the medium to longer term, where an increased regulatory response may be required to support the NSW Government’s climate change commitments and policies, including achieving net-zero emissions in NSW by 2050.	NSW EPA (2023b)
<i>Strategic Plan 2024–29</i>	Describes how the EPA will deliver stewardship for the environment to protect, restore and enhance the environment and human health. It sets out commitments to effective regulation and a focus on high quality environmental outcomes across all of EPA’s work. The plan details objectives and outcomes for three key areas: - caring for country - driving action on climate change - enabling a safe circular economy.	NSW EPA (2024b)
<i>Waste Delivery Plan</i>	Outlines the actions the EPA take to reduce the harmful impact of waste and drive behaviours that create a circular economy. The Waste Delivery Plan includes actions to reduce carbon emissions and building the resilience of the waste sector to climate change.	NSW EPA (2021)

iii NSW safety legislation

In NSW, coal mines are required to meet the safety requirements set out in:

- *Work Health and Safety (Mines and Petroleum Sites) Act 2013*
- *Work Health and Safety (Mines and Petroleum Sites) Regulation 2022.*

Further references to these are made later in this report.

The NSW Resources Regulator has also published guidance on mine ventilation control:

- *Technical Reference Guide - Ventilation Control Plan, Guide for the Development of a Ventilation Control Plan for Underground Mines*¹¹.

2.6 NSW EPA licensee climate change survey

Between August and October 2023, NSW EPA conducted a licensee climate change survey. This supported Action 5(a) of the EPA’s *Climate Change Action Plan 2023–26*. The purpose of the survey was to enable the EPA to understand how it could help licensees (the holders of EPLs) to reduce their GHG emissions and the impacts of climate change on their operations. The results of the survey are available to the public through the climate change survey dashboard (NSW EPA 2024a). Each response to a survey question is presented in terms of the number of facilities providing the response.

The results for the coal mining sector are summarised below:

- 81% of licensees said that their main driver for climate change management was it being a strategic priority for the organisation.
- 85% of licensees said that they received support from their industry associations on climate change management issues.

¹¹ <https://www.resources.nsw.gov.au/sites/default/files/documents/trg-ventilation-control-plan.pdf>

- 57% of licensees said that they had undertaken a climate change risk assessment (CCRA) for their facilities.
- 43% of licensees said that they reported under the NGER scheme, with 35% having Safeguard Mechanism facilities.
- Of those licensees that had assessed emissions, the main sources of scope 1 emissions they reported were fugitive emissions from coal seams (51% of responses) and non-road vehicles and equipment (45% of responses).
- 37% of licensees said they had an emission-reduction plan.
- The emission-reduction approaches licensees said they had implemented to date included energy efficiency, process optimisation, renewables, planting trees, greener fuel, methane capture and flaring, and electricity generation from methane.

3 Literature review

3.1 Methodology

The methodology for the literature review involved the following steps:

1. Searches to identify publicly available documents, including:
 - government policies, regulations and reports
 - technical publications from organisations
 - magazine articles and news items.
2. Searches of major international databases of scientific publications (Science Direct, ResearchGate, Google Scholar).
3. An initial screening of documents to determine their relevance and detail, resulting in a shortlist. Given the quickly changing nature of science, policy and technology in relation to climate change and GHG management, the emphasis was placed on documents from approximately the last decade (around 2014 to 2025).
4. Cataloguing of the shortlisted documents in a review register (Excel spreadsheet), with each document given a unique identifier.
5. A more in-depth consideration of each shortlisted document in the review register, including the general coverage of topics (e.g. guidance, mitigation, monitoring), a rating of the document's relevance to the study (low, medium or high), and summary comments.

The review register contained 50 separate shortlisted documents. Of these, 8 documents mainly provided contextual information, 14 were categorised as guidance, and 27 were considered to concentrate more on mitigation measures, although in practice there were some considerable overlaps. A subset of documents (12) was considered to have a high importance to the review. Most of the documents were categorised as having medium or low importance, either because they lacked depth across a range of topics, or were too specialised for the purpose of the review (i.e. they focussed in detail on a particular topic).

It is important to recognise that several of the topics covered in the literature review represented large fields of study, and therefore they could not be covered comprehensively. Some examples of this included the geology of coal mines, coal mining techniques, vehicle powertrain technology and mine automation. Where appropriate, information for mining sectors other than coal (e.g. metal ore) was used.

A qualitative analysis of existing and emerging GHG mitigation measures was also conducted.

The findings of the literature review are provided in the following sections of this chapter.

3.2 Coal mining processes and emission sources

This section describes the coal mining process and sources that generate scope 1, scope 2 and scope 3 emissions. It also considers the factors that influence emissions from coal mining activities.

3.2.1 Mining processes

Depending on the feasibility of an extraction operation, coal can either be extracted using open-cut or underground mining methods.

In underground mines there are two main techniques for coal extraction, namely longwall and bord-and-pillar¹², although both have variants. Longwall mining uses a mechanical shearer to progressively mine slices of the retreating longwall face, with the extracted coal being removed by conveyor belt. As the machinery moves along the seam, a hydraulic support system holds the overlying rock in place. In bord-and-pillar mining, a continuous miner cuts into the coal seam, partially removing the coal. Pillars of coal are left intact to support the overlying layers of rock. Again, the coal is transported to the surface on a conveyor belt. Mining by this method creates a network of alternating open spaces and pillars. Once mining in one part of the coal seam has finished, the machinery is retracted and the coal in the pillars is also extracted in some cases, allowing the roof to collapse behind (Geoscience Australia 2023; UNECE 2021).

Open-cut mining methods are generally deployed where a coal seam is closer to the surface and, in this case, the approach is more practical than underground mining. These methods enable up to 90% recovery of the coal resource. Firstly, the vegetation and topsoil are removed and stored for use later during rehabilitation. The surface rock (called overburden) covering the coal is then blasted with explosives and removed by excavators. The uncovered coal is, in turn, blasted to break up the layers and loaded into haul trucks. The coal is then transported to a processing plant where impurities are removed (Geoscience Australia 2023).

Some black coal can be used without any processing, but it is usually crushed, screened and sorted according to customer requirements. Sometimes it is also washed to remove any waste minerals. This improves the quality and reduces the production of ash when the coal is burned. The coal is then either loaded directly into trains or trucks for transport, or stockpiled on-site (Geoscience Australia 2023).

3.2.2 Scope 1 emissions: fugitive methane

Various on-site activities and processes generate scope 1 emissions, and these are summarised by mine type in Table 3.1. Descriptions of the processes are provided in the following sections, and their aggregated contributions to scope 1 and scope 2 emissions are considered in section 3.3.

i Overview, terminology and reporting

Fugitive emissions are losses and leaks of gas to the atmosphere, and at coal mines they occur during every stage of the mine life cycle. For GHG accounting under NGERs, fugitive emissions are specifically those that are:

- released in connection with, or as a consequence of, the extraction, processing, storage or delivery of fossil fuel
- not released from the combustion of fuel for the production of useable heat or electricity.

Fugitive emissions constitute one of the largest sources of GHGs from coal mining, mainly due to emissions of methane, although CO₂ is also released. Various terms are used in the literature to refer to methane emissions from coal mines, and the usage is often ambiguous. The terms used in this report are defined in the glossary (section A.1).

The reporting of fugitive emissions at the facility level has come under scrutiny in recent years (CCA 2024) and reporting methods are under review by the Australian Government.

The NSW EPA has also commissioned CSIRO to prepare a review of monitoring techniques for fugitive methane emissions.

¹² Also referred to a 'room-and-pillar' in the literature.

Table 3.1 Common GHG emission sources for coal mines: scope 1

GHG source		Process examples	Relevance to mine type (typically)		
			Underground mines (active)	Surface mines (active)	Underground mines (closed)
Fugitive CH ₄	Coal seam gas	Drainage of gas with venting	Yes	No	No
		Drainage of gas with flaring	Yes	No	No
		Drainage of gas with utilisation (e.g. electricity generation)	Yes	No	No
		Venting of mine ventilation air	Yes	No	No
		Exposure of coal seam at surface	No	Yes	No
		Leaks from closed mine areas	No	No	Yes
	Coal stockpiles	Post-mining emissions	Yes	Yes	No
Diesel combustion ^(a)	Scrapers, front-end loaders	Stripping topsoil	No	Yes	No
	Bulldozers	Moving overburden, pushing coal, creating roads	Yes ^(b)	Yes	No
	Drills	Obtaining coal samples, blast hole drilling	No	Yes	No
	Excavators	Removing coal from a seam	No	Yes	No
	Haul trucks	Hauling overburden to emplacement areas, hauling coal to processing facilities or stockpiles	Yes	Yes	No
	Loaders	Loading haul trucks and material handling	Yes	Yes	No
	Graders	Grading roads to create flat surfaces	Yes ^(b)	Yes	No
	Other trucks	Transport of workers, equipment and materials	Yes	Yes	No
	Pumps, compressors	Removal of excess water, supply of compressed air for pneumatic tools	Yes	Yes	No
	Water carts	Control of dust on roads and work areas by spraying water	Yes ^(b)	Yes	No
	Generators	Lighting, ventilation (where electricity from the grid is unavailable)	Yes	Yes	No
	Light-duty vehicles	Transport of personnel, mine maintenance, surveying, inspection, environmental monitoring	Yes	Yes	No
Petrol combustion	Small portable equipment	Ancillary operations	Yes	Yes	No
ANFO ^(c) combustion	Blasting	Blasting (e.g. overburden)	No ^(d)	Yes	No
Oils, greases	Lubricants	Equipment maintenance and cleaning	Yes	Yes	No
Fugitive SF ₆	Electrical equipment	Insulation for high-voltage switchgear, circuit breakers, and transformers	Yes	Yes	No
Coal oxidation	Coal stockpiles	Low-temperature oxidation and spontaneous combustion in poorly managed coal stockpiles.	Yes	Yes	No
Vegetation removal ^(e)	Removal of vegetation prior to mining	Removal of vegetation results in the loss of an existing carbon sink	Yes	Yes ^(f)	No

Notes

(a) In some cases, equipment can be powered by electricity rather than diesel.

(b) For operations at the surface.

(c) ANFO = ammonium nitrate fuel oil.

(d) Some limited blasting occurs at underground mines.

- (e) This can be taken into account in state and national land-use change models. It is not currently considered in detail in all project-based GHG assessments, and is not part of NGER reporting.
- (f) Noting that there will be an ongoing loss of the carbon sink that occurred during the operational phase of a mine.

ii Coal seam gas

The processes which create coal and subsequent geological events also produce gas which is trapped within the coal seam. This gas, which is composed primarily of methane and CO₂, is therefore referred to as coal seam gas (CSG). The disturbance of the coal seam and intervening strata during underground and surface mining can cause the CSG to be released.

The methane (and CO₂) content of the CSG¹³ is variable, and can range from less than 1 m³/t to over 20 m³/t (UNECE 2021). The quantity of gas contained in the coal¹⁴, and the rate at which is then emitted by a mining operation, are influenced by several factors, including the following (Black and Aziz 2009; Karacan et al 2011; UNECE 2016, 2021; USEPA 2019a; IEA 2023a; Karacan et al 2024):

- Coal rank. This is a measure of the thermal maturity of the coal. Higher ranks of coal generally have higher carbon (and methane) contents, although the relationships between coal rank, carbon contents and gas contents are variable, site-specific, and influenced by the post-depositional history of the sediments. Anthracite and bituminous coal are of highest ranks, whereas lignite has the lowest rank.
- Coal depth. Pressure plays an important role in the formation of coal and CSG. Because pressure increases with depth, deeper coal seams generally tend to contain more CSG than shallower ones. Given the influence of coal depth on CSG, underground mines tend to have higher methane emissions than surface mines. In addition, deeper seams may have less methane migration to the surface; gas from near-surface seams may have escaped to the atmosphere long before mining began.
- Coal permeability. Permeability is a measure of how easily gas can flow through a coal seam. Where coal permeability is high, gas can migrate more easily through the seam and fractures, and this can lead to increased release of gas emissions during mining.
- Mining method. Underground longwall mines tend to release more CSG than other types of mining because (i) a greater volume of the gas-bearing strata (i.e. the coal) is removed, and (ii) the caving of overburden strata and depressurisation of the sedimentary sequence disturbs roof and floor formations. Bord-and-pillar mines generally release less gas than longwall mines because they disturb less of the strata per tonne of coal mined, although this is not always the case (it depends on the coal seam). However, where the pillars are removed as a final phase of mining, additional gas release can occur due to the strata disturbance when the pillars supporting the roof are removed to allow caving.
- Coal extraction rate. The greater the volume of coal disturbed per unit of time, the higher the CSG release rate, all else being constant.
- Mining progression. As mining progresses in a coalfield, changes in geology, CSG reservoir properties, mining rate and interactions between workings in different seams lead to variability in gas flows and concentrations.

Given the various factors that influence gas generation and release, there is considerable variability in gas content and composition, as well as the ability to drain gas from coal seams (Black and Aziz 2009).

¹³ CSG in deeper coal seams typically contains a high proportion (up to around 95%) of methane, with lower proportions of ethane, propane, nitrogen and CO₂. However, in coal seams closer to the surface, the CO₂ proportion can be much higher.

¹⁴ Sometimes referred to as the mine's 'gassiness'.

iii Methane from active underground mines

Methane, which is often the principal component of CSG, is explosive in concentrations in air ranging from 5% to 15%, and in active underground mines it poses a serious risk to health and safety (USEPA 2019a). The management of CSG is therefore a major safety requirement for underground coal mines. Underground mines require sufficient fresh air to provide safe working conditions¹⁵. CSG is typically removed from a mine and diverted to the surface through large-scale ventilation systems, typically extracting air at hundreds of cubic metres per second. Methane contained in the extracted air is referred to as ventilation air methane (VAM). VAM is exhausted from the ventilation shaft at a low methane concentration, typically in the range of 0.1% to 1.0%. As well as containing methane and the other gases in CSG, ventilation air (VA) also includes particulate matter, oxides of nitrogen, ammonia, sulfur dioxide and hydrogen sulfide (Rahimpour 2023). Another common approach in underground mines is draining CSG from the seam before, during or after mining. This can reduce the ventilation requirements and the release of methane in mine ventilation air. Further details of ventilation and drainage are given in section 3.6.1.

The handling, processing, transport and storage of mined coal during the active mining phase can cause methane trapped in the matrix of the coal to be released. These releases of methane are collectively grouped as 'post-mining emissions' (UNECE 2021). Post-mining emissions are quantified under NGERs. Most of the information in the literature appears to relate to the storage of coal in stockpiles. The stockpiling of coal is carried out at various points in the mining process, and the mechanisms that lead to emissions of methane have been described by Zhang (2013). As coal is exposed to the air, methane that was adsorbed onto the coal surface or trapped in its pores can desorb. The gas desorption rate and degree depend on particle size, surface moisture, temperature and pressure.

In Australia, some mines have remained in 'care and maintenance' for several years without being fully closed. For these mines, fugitive methane emissions are released from coal seams and ventilation shafts that have remained open.

iv Methane from active surface mines

At surface mines, gas is released as the overburden is removed and the coal seam is exposed and then broken up. Methane escapes from newly exposed coal faces and surfaces, coal rubble created by blasting, overburden, and the underlying strata which may be fractured. This gas is collectively referred to in the international literature as surface mine methane (SMM). For shallow coal seams, the methane emissions per tonne of coal removed will tend to be lower than those from underground mines. For deeper coal seams (e.g. below 200 metres), methane emissions at the surface can be more significant. Gas drainage can also be applied to surface mines in principle, although this is not conducted at coal mines in NSW and appears to be uncommon overseas.

v Methane from closed underground mines

For an underground mine, most methane emissions occur during the active phase of the mine life cycle. However, fugitive emissions from closed mines can continue for decades in the absence of mitigation. This gas is commonly referred to in the international literature as abandoned mine methane (AMM). Research has suggested that closed mines could be a significant source of methane, especially as more mines reach the end of their operational lifetimes (IEA 2023a).

¹⁵ In NSW, Section 76 of the *Work Health and Safety (Mines and Petroleum Sites) Regulation 2022* prescribes control and monitoring of methane levels in coal mines. Sub-Division 3 of Section 76 (Control and Monitoring of Methane Levels) which states that the 'general body of air in the areas in which persons work or travel has a concentration of methane that (a) is as low as reasonably practicable, and (b) is not greater than 2% by volume.

When a mine is closed, all services are severed, including ventilation and drainage. Methane is still released from fractured formations into the previously mined workings. Fugitive emissions occur via seals/shafts, venting pipes left in drifts and shaft covers, surface cracks and geological discontinuities. External factors, such as surface temperature, atmospheric pressure and wind speed and direction may also affect methane emissions from a closed underground mine (Karacan et al 2024).

Methane emissions decline gradually over time as the source decays or once the shaft is submerged under water, and there is no mining activity (UNECE 2021). Liu et al (2021) explain that the amount of gas released from a closed mine depends on when the mine was closed, whether it was flooded prior to the closure, the overall gas content of the coal, and the network of escape passages.

3.2.3 Scope 1 emissions: diesel combustion

Diesel vehicles and equipment are currently widely used at active surface mines, and to a lesser extent at underground mines. Coal (and other material) extraction, processing and transport therefore involve the combustion of significant quantities of fuel. The diesel vehicles and equipment used at coal mines were summarised in Table 3.1. These include haul trucks, bulldozers, excavators, loaders, pumps and generators. Diesel engines are used in these applications because they are durable, reliable, and flexible; they cover wide ranges of capacity and rated power. Typically, the hauling of overburden and coal at open-cut mines accounts for a large proportion of on-site diesel use. Various parameters can affect the diesel consumption of the haul truck fleet, including vehicle type, size, power, age and the level of maintenance, the haulage distance, the speed, the payload and the rolling resistance.

Diesel can also be consumed in smaller quantities at mines during care and maintenance and decommissioning.

3.2.4 Scope 1 emissions: other minor sources

i Petrol combustion

The use of petrol in internal combustion engines is usually a relatively small contributor to GHG emissions at NSW coal mines, and can be zero. Petrol use is mostly limited to ancillary operations, such as small, portable equipment. Although light-duty vehicles are used for activities such as transporting personnel, conducting mine maintenance, surveying, inspection and environmental monitoring, these are mostly diesel-engined.

ii ANFO combustion

Large amounts of ammonium nitrate fuel oil (ANFO) explosive are used in coal mining. During blasting, the oxidation of the fuel oil component of ANFO produces CO₂. Typically, around 0.2 tonnes of CO₂-e are produced per tonne of ANFO used.

iii Oils and greases

At coal mines, petroleum-based oils and greases are used to lubricate equipment, to protect equipment against corrosion, and for cleaning. Oils and greases contribute to GHG emissions through combustion, oxidation and volatility. They are only a minor source of scope 1 emissions at coal mines.

iv Fugitive SF₆

Sulfur hexafluoride (SF₆) is an important GHG, with a global warming potential of 23,500 times that of CO₂ over a 100-year period, and an atmospheric lifetime of 800 to 3,200 years.

At coal mines, SF₆ is used as a cooling gas and insulator in high-voltage electrical switchgear, circuit breakers and transformers. The insulating properties of SF₆ have allowed electrical equipment to become smaller, easier to maintain and safer for high electrical loads (USEPA 2018).

Leaks of SF₆ from electrical equipment can occur – typically from locations such as flanges and seals – through poor construction, poor maintenance and component failure. Equipment can deteriorate and result in emissions of SF₆ if subject to high ambient temperatures, chemical changes, corrosion or events that can cause sudden damage. Emissions can also occur as a result of poor operational practices (e.g. gas handling).

SF₆ is another relatively minor contributor to GHG emissions at coal mines. However, its importance is likely to increase in line with greater mine electrification, as discussed in other sections of this report.

v Coal oxidation

Low-temperature oxidation and spontaneous combustion occur when coal is exposed to the air, such as in stockpiles, depending on coal rank and environmental conditions.

Zhang (2013) explained that as soon as coal is exposed to air it undergoes low-temperature oxidation through reaction with atmospheric oxygen. This process can be sustained if the heat produced by the oxidation cannot be sufficiently dissipated. The main GHG from oxidation at ambient temperatures is CO₂. The oxidation process can be gradual but continuous, leading to a slow release of CO₂ over time. The CO₂ emission depends on factors such as the extent of the exposure to air, coal moisture content and coal type.

In some large and poorly managed stockpiles, spontaneous combustion can occur. This is a self-sustaining chemical reaction where heat is generated within the stockpile, potentially leading to more rapid oxidation and CO₂ emissions. At the elevated temperatures in stockpiles affected by spontaneous combustion, parts of the coal can be starved of oxygen, with the result that methane can also be produced. Coals with a higher content of volatile compounds, concentration of sulfide minerals such as pyrite, or bituminous and anthracite coals, are more prone to spontaneous combustion. Accumulated coal dust can also be a contributing factor, as it facilitates the spread of combustion.

vi Vegetation removal

Vegetation at a mine site will generally be removed prior to mining, therefore resulting in the loss of a carbon sink (the vegetation would remove CO₂ from the atmosphere). This effectively represents a GHG emission during the lifetime of the project. Revegetation is a requirement for most mines once mining is completed, although the carbon sink may not necessarily be fully restored to its original state.

In addition, the removed vegetation will be mulched, burned or left to decompose over a long period, which leads to further GHG emissions.

3.2.5 Scope 2 emissions

Scope 2 emissions are indirect emissions associated with the off-site generation of the electricity (or less commonly at coal mines heating, cooling or steam) that is consumed by a mine. The main equipment and processes at coal mines that use electricity, and hence generate scope 2 emissions, are summarised in Table 3.2.

The magnitude of the GHG emissions from each process depends on the amount of electricity used by the process (e.g. MWh/year) and the emission intensity of the electricity source (e.g. t CO₂-e/MWh). The electricity is often taken from the grid, and therefore its emission intensity is dependent on the grid's generation mix.

Projections of GHG emissions in Australia, including the emissions intensity of electricity generation by state, are provided by DCCEEW (2024). The scope 2 emission intensity projections for Australia and NSW are shown in Figure 3.1. The NSW grid is undergoing rapid decarbonisation. In 2025, the scope 2 emission intensity is 0.51 t CO₂-e/MWh. By 2040, it reduces to 0.03 t CO₂-e/MWh, due in large part to the closure of remaining coal-fired power stations.

In the future, the scope 2 GHG emissions from coal mining in NSW will be the net result of (i) changes in coal production (and energy use), (ii) a probable general increase in mine electrification, and (iii) the reduction in the emission intensity of grid electricity.

Table 3.2 GHG emission sources for coal mines: scope 2 (electricity consumption)

Equipment ^(a)	Process examples	Underground mines	Surface mines
Draglines, electric shovels	Removing overburden and excavating coal. Tethered to electricity supply	No	Yes
Conveyors	Transporting coal from the mining face to processing areas, stockpiles or trains	Yes	Yes
Cutting machines (shearers/continuous)	Removal of coal and other rocks from underground workings	Yes	No
Crushers and screeners	Crushing and screening coal to prepare it for transport and sale	Yes	Yes
Communications	Communication networks, including radio systems, alarms and monitoring systems	Yes	Yes
Winding systems	Winches and hoists to transport personnel and materials in and out of the mine shafts, and transporting mined coal	Yes	No
Pumps, compressors	Removal of excess water, supply of compressed air for pneumatic tools	Yes	Yes
Lighting	Lighting for tunnels, work areas and safety signage	Yes	Yes
Loaders	Loading coal onto trucks in underground mines	Yes	No
Underground trucks ^(b)	Hauling coal to the surface	Yes ^(a)	No
Fans	Circulating fresh air through the mine to remove exhaust gas and dust	Yes	No

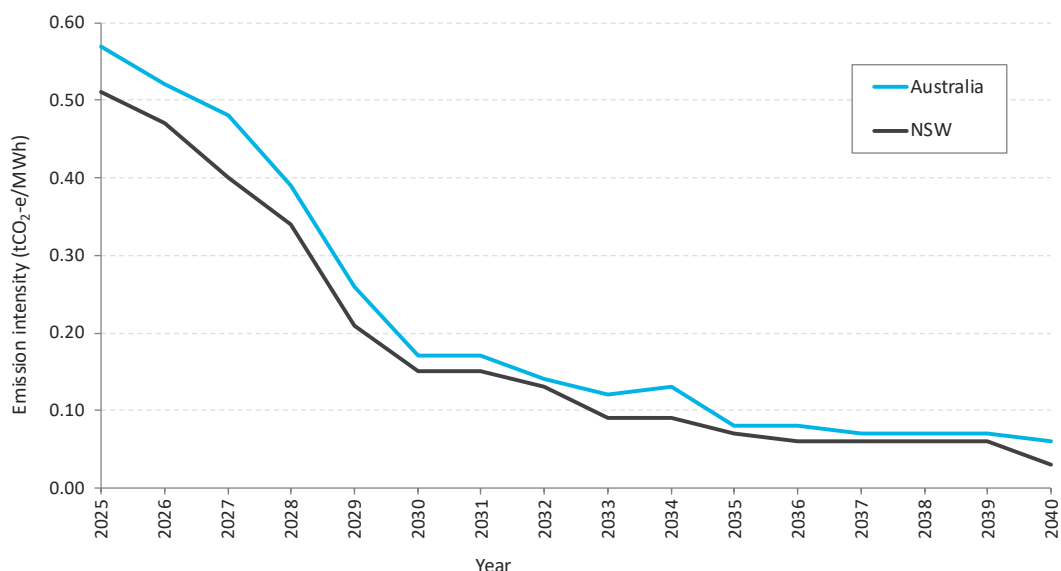
Notes

(a) In some cases, equipment may be powered by diesel.

(b) Mainly demonstration projects at the time of writing ^{16, 17}.

¹⁶ <https://www.australianmining.com.au/cat-demonstrates-first-battery-electric-underground-mining-truck/>

¹⁷ <https://thedriven.io/2023/09/27/largest-electric-underground-mining-truck-begins-trial-at-australian-gold-mine/>



Source: DCCEEW (2024)

Figure 3.1 Scope 2 emission intensity of grid electricity

3.2.6 Scope 3 emissions

Scope 3 emissions occur upstream and downstream of coal mines. Some of the main processes that generate scope 3 emissions are summarised in Table 3.3. In Australia, scope 3 emissions are not reported under the NGER scheme and there is no legal requirement to mitigate them.

Table 3.3 GHG emission sources for coal mines: scope 3

GHG emission sources and processes	Underground mines	Surface mines
Indirect upstream emissions		
Extraction, production and transport of diesel	Yes	Yes
Extraction, production and transport of petrol	Yes	Yes
Production and transport of ANFO	Yes	Yes
Extraction, production and transport of oil and grease	Yes	Yes
Manufacture and transport of SF6	Yes	Yes
Manufacture and transport of mine vehicles and equipment	Yes	Yes
Embodied emissions in construction materials	Yes	Yes
Electricity lost in delivery in the transmission and distribution network	Yes	Yes
Indirect downstream emissions		
Product coal utilisation(a)	Yes	Yes
Product coal transport	Yes	Yes
Waste disposal	Yes	Yes
Disposal of mine vehicles and equipment	Yes	Yes
Combustion of captured waste gas	Yes	No

Notes

- (a) Product coal is used for a variety of purposes, including coal-fired power generation, iron production and chemical feedstocks.

In September 2024, the *Treasury Laws Amendment (Financial Market Infrastructure and Other Measures) Bill* was passed by Parliament. This introduced a framework for Australia’s mandatory climate-related financial disclosure regime, which requires large organisations to report their scope 1, 2 and 3 GHG emissions on an annual basis. Reporting for the affected organisations would be phased in over a four-year period. Reporting of scope 3 emissions will be required from the second year of reporting. Mandatory scope 3 reporting will ensure that organisations have a better understanding of their upstream and downstream emissions as they gather these data from their suppliers and end users. Along with understanding emissions, they will also gain a clearer view of the measures to reduce them.

Some additional information on upstream and downstream emissions for coal mines is presented below.

i Upstream emissions

For liquid fossil fuels (e.g. petrol, diesel) and other fossil derivatives (e.g. oil, grease), upstream emissions are generated during oil exploration, oil extraction, oil refining, transport and distribution, and refuelling. Ammonium nitrate manufacture (for use in ANFO) is also energy intensive¹⁸.

Upstream emissions are also associated with the manufacture and supply of mine vehicles and equipment, and the production and transport of materials used in on-site construction. Emissions for transport to mine sites are likely to be significant. Non-road diesel engines and equipment are not manufactured in Australia; they are all imported, either as loose engines or already incorporated into equipment. Engines are imported into Australia from approximately 25 countries, the major sources being China, EU countries and the US (Boulter et al 2022).

Other minor upstream sources include employee travel and contractor-related emissions.

ii Downstream emissions

Downstream emissions include product coal utilisation, product transportation (e.g. road, rail and shipping), the disposal of mine vehicles and equipment, and the combustion of captured waste gas. Transport of coal is a significant contributor to scope 3 emissions, particularly in cases where the coal is exported overseas. Combustion of coal by end users (for power generation or steel production) is typically the most significant source of an organisation’s scope 3 emissions, and is also often the largest contributor to total GHG emissions.

In the case of captured waste gas, these emissions are treated as Scope 1 emissions if re-used by an organisation on-site, but are treated as Scope 3 emissions if sold to the gas market and combusted by another organisation.

3.3 GHG emissions data

This section summarises the nature and scale of GHG emissions from the coal mining sector. Detailed emissions data from individual sources (notably for projections) are not publicly available, and therefore a more complete picture cannot be provided.

Table 3.4 summarises the contributions of all mining and coal mining to direct GHG emissions in Australia and NSW for the financial year 2021–22. During this period, the Australian mining sector was responsible for around 100 Mt of CO₂-e per year, or 23% of national emissions across all sectors. Coal mining was responsible for around 35 Mt of CO₂-e/year, or 8% of national emissions. In NSW, the mining sector was responsible for 13% of state-wide GHG emissions, with coal mining being the main source, at 12% of state-wide emissions.

¹⁸ <https://www.climateleaders.org.au/case-studies/incitec-pivot-1/>

Table 3.4 Greenhouse gas emissions in Australia and NSW in 2021–22

Sector/sub-sector	Process	GHG emissions (Mt CO ₂ -e/year) ^(a)	
		Australia	NSW
All economic sectors	All	432.6 (net)	111.0 (net)
Mining only	All	101.3	14.8
Coal mining only	All	34.9	13.9 ^(b)

Notes

(a) <https://greenhouseaccounts.climatechange.gov.au>

(b) Estimate based on data from Australia's National Greenhouse Accounts (ANGA), emissions by state and territory (<https://greenhouseaccounts.climatechange.gov.au/>). The non-road diesel portion for coal mines was estimated using Commonwealth non-road diesel engines – cost-benefit analysis report (Boulter et al 2022).

Table 3.5 shows the breakdown of emissions from the NSW mining sector in 2021–22. It should be noted that this includes contributions from non-coal mining. Fugitive emissions from coal mining, and fuel combustion emissions associated with (all) mining machinery accounted for 99% of the direct GHG emissions from the resources sector in NSW. Most of the emissions from the mining sector are from fugitive methane, with contributions from carbon dioxide, and fugitive emissions are almost entirely from coal mining. According to the Net Zero Commission (2024), fugitive emissions from underground coal mines in 2021–22 were around 8 Mt CO₂-e, while open-cut coal mines contributed around 2 Mt CO₂-e. The Net Zero Commission also notes that emissions from fuel combustion are primarily associated with heavy machinery operation in resource extraction, and approximately 90% of these emissions are from coal mines.

Table 3.5 Greenhouse gas emissions from the NSW mining sector in 2021–22

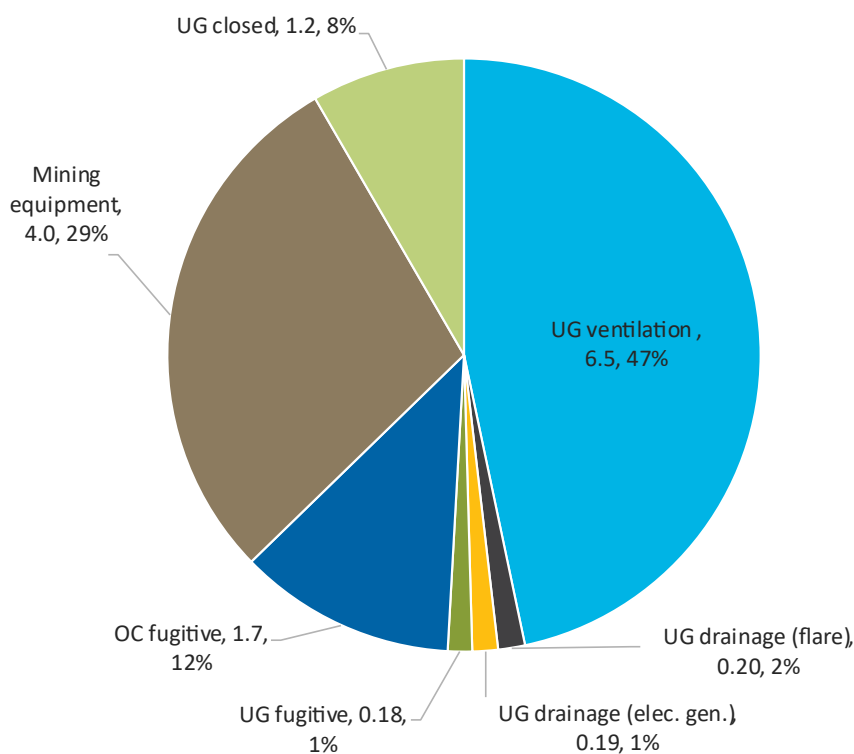
Source	GHG emissions (Mt CO ₂ -e/year) ^(a)
Fugitive emissions from coal mining	10.0 (72.7%)
Fuel combustion in mining	3.7 (26.7%)
Fugitive emissions and fuel combustion from oil and gas	0.1 (0.6%)
Total	13.8

Note

(a) Net Zero Commission (2024)

Figure 3.2 presents scope 1 emissions from coal mining in NSW by source in 2021–22. The figure shows that diesel equipment was responsible for 29% of emissions, and underground (UG) mine ventilation (i.e. VAM) was responsible for 47%. Fugitive emissions from surface (OC) mines (12%) and closed mines (8%) were also significant.¹⁹

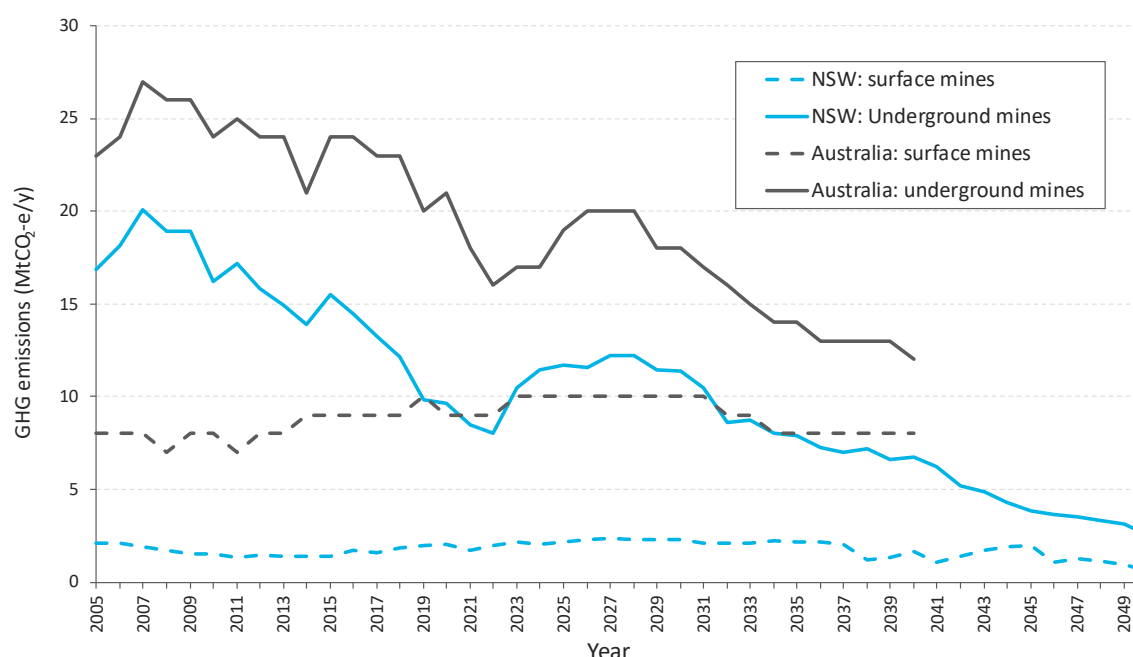
¹⁹ The reporting of fugitive emissions at the facility level has come under scrutiny in recent years (CCA 2024) and reporting methods are under review by the Australian Government. The NSW EPA has also commissioned CSIRO to prepare a review of monitoring techniques for fugitive methane emissions.



Source: Estimate based on data from ANGA and CSIRO (2024)

Figure 3.2 Emissions from coal mining in NSW by source in 2021-2022 (scope 1, Mt CO₂-e/y)

Complete time series emissions data for all sources in the mining sector in NSW are not publicly available. However, time series of fugitive emissions are available, as shown in Figure 3.3. For underground mines, fugitive emissions have followed a general downward trend historically, and this is projected to continue in the future. Although emissions are projected to grow in the 2020s, due mainly to increased coal mining, they are projected to start decreasing as mining activity slows (NSW DCCEEW 2024a). By 2040, emissions are projected to be around 40% lower than those in 2005 in NSW, and around 50% lower in Australia. Emissions from surface mines are more stable over time, changing little between 2005 and 2040. According to the ANGA data, scope 2 emissions from all mining in NSW in 2021–22 were 2.9 Mt CO₂-e/year.



Source: NSW data from NSW projected GHG emissions (NSW DCCEEW 2024b) and Australia's emissions projections (DCCEEW 2024)

Figure 3.3 Time series of emissions for fugitive coal mine emissions for NSW and Australia

3.4 Guidance on greenhouse gas mitigation

This section summarises the existing guidance documents and resources relating to the mitigation of GHG emissions from coal mines, based on a search of publicly available information. It covers guidance from Australia, the United States, Europe and international organisations. The section does not provide a detailed description of each document, and the original material should be consulted where more depth is required. The content of the most relevant guidance documents, in terms of importance to the study is also considered.

3.4.1 Guidance in Australia

i Australian Government agencies

Specific guidance published by Australian Government agencies includes *Energy Management in Mining* (Crittenden et al 2016). The Department of Climate Change, Energy, the Environment and Water also provides on-line guidance on energy efficiency for businesses and sectors, including mining²⁰.

ii New South Wales

a NSW Guide for Large Emitters

The EPA's *NSW Guide for Large Emitters* (NSW EPA 2025) sets out the GHG assessment and mitigation requirements of the environmental assessment and approvals process for projects which are likely to have large emissions. It helps proponents to prepare a GHG assessment and develop emission-reduction goals. It also supports the EPA and the consent authority as they review the adequacy of GHG assessments for new proposals, or proposed significant modifications to existing facilities. The Mitigation Guide for coal mines is designed to support the *NSW Guide for Large Emitters*.

²⁰ <https://www.energy.gov.au/business/sector-guides/mining>

b Katestone Best Practice Checklist for Greenhouse Gas Abatement by NSW Coal Mines

In 2023, the then Department of Planning and Environment (DPE) commissioned Katestone to produce a *Best Practice Checklist for Greenhouse Gas Abatement by NSW Coal Mines* (Katestone 2023). The checklist is an internal document for DPE, and the EPA and the coal mining industry were not involved in its development. The purpose of the checklist is to support planning assessment officers when reviewing post-approval GHG management plans, as required as a condition of consent for approved coal mining projects in NSW. The checklist is designed to serve as a benchmark to help the DPE to determine the adequacy of post-approval management plans, with respect to the implementation of GHG mitigation measures by proponents.

The checklist identifies a range of measures for dealing with GHG emissions at underground and open-cut coal mines. It considers scope 1, 2 and 3 emissions, and distinguishes between measures that are considered to be 'below best practice', 'best practice' and 'emerging best practice'.

The checklist focuses on measures for fugitive methane and diesel consumption. It uses a high-level approach, and does not describe specific measures in detail. It does not cover certain processes, such as gas drainage, coal stockpile management and the flooding of mines.

iii Other Australian jurisdictions

The policy and guidance on GHG emissions from the other Australian jurisdictions is summarised in Table 3.6. However, these documents contain little information that relates specifically to coal mining.

Table 3.6 Guidance on GHG emissions in other Australian jurisdictions

Jurisdiction	Guidance
Victoria	• <i>Guideline for minimising greenhouse gas emissions</i> (EPA Victoria 2022) • <i>Climate change, biodiversity and engagement requirements</i> (EPA Victoria 2023)
Queensland	• <i>Guideline - Greenhouse gas emissions</i> (Queensland Government 2024)
South Australia	• <i>Environment Protection Act 1993</i> (including climate change mitigation and adaptation related) and Environment Protection Policies
Western Australia	• <i>Greenhouse Gas Emissions Policy for Major Projects</i> (WA DEMIRS 2019) • <i>Environmental Factor Guideline – Greenhouse Gas Emissions</i> (WA EPA 2023)
Tasmania	None
Northern Territory	• <i>Greenhouse Gas Emissions Management for New and Expanding Large Emitters</i> (Northern Territory Government 2021) • <i>Policy Statement: Management of Greenhouse Gas Emissions from the Onshore Gas Industry</i> (Northern Territory Government 2023)
Australian Capital Territory	• <i>Reporting greenhouse gas emissions</i> (ACT Government 2024)

3.4.2 Guidance in the United States

Various relevant guidance documents have been published by the United States Environmental Protection Agency (USEPA), including:

- *Overview of SF₆ Emissions Sources and Reduction Options in Electric Power Systems* (USEPA 2018)
- *Ventilation Air Methane (VAM) Utilization Technologies* (USEPA 2019a)
- *Global Non-CO₂ Greenhouse Gas Emission Projections & Mitigation 2015-2050* (USEPA 2019b).

3.4.3 Guidance in Europe

Tackling GHG emissions is a priority of the European Green Deal²¹. The *EU Strategy to Reduce Methane Emissions* (European Commission 2020) focuses on reducing methane emissions in the energy, agriculture and waste sectors. The cross-sectoral approach takes targeted action in each area while also promoting synergies across sectors.

To support the delivery of the strategy, the *Regulation on methane emissions reduction in the energy sector* (EU/2024/1787) entered into force in August 2024. The regulation aims to stop the avoidable release of methane into the atmosphere, both in the EU and in its global supply chains, and to minimise leaks of methane by fossil energy companies operating in the EU. For coal mining, the regulation envisages a phasing-out of methane venting and flaring. It also obliges EU countries to establish mitigation plans for closed coal mines.

3.4.4 Guidance in China

In 2025, the Chinese Ministry of Ecology and Environment released a new methodology to incentivise projects using coal mine gas (drainage gas and VAM) with methane concentrations below 8%. Currently this methodology is only available in Chinese²². However, it is likely to contain relevant information for these sources.

3.4.5 Guidance from international organisations

i United Nations Economic Commission for Europe

The United Nations Economic Commission for Europe (UNECE) promotes sustainable development in the energy sector, and facilitates international economic cooperation. Promoting the capture and use of methane is carried out under the Group of Experts on Coal Mine Methane. The UNECE collaborates with the USEPA on developing and releasing best practice guidance.

Various relevant guidance documents have been published by the UNECE, including:

- *Best Practice Guidance for Effective Methane Drainage and Use in Coal Mines* (UNECE 2016)
- *Best Practice Guidance for Effective Methane Recovery and Use from Abandoned Coal Mines* (UNECE 2019)
- *Best Practice Guidance for Effective Management of Coal Mine Methane at National Level: Monitoring, Reporting, Verification and Mitigation* (UNECE 2021)
- *Best Practice Guidance on Ventilation Air Methane (VAM) Processing* (UNECE 2024)
- *Best Practice Guidance on Ventilation Air Methane (VAM) Mitigation* (UNECE 2025).

²¹ https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/european-green-deal_en

²² https://www.mee.gov.cn/xxgk2018/xxgk/xxgk06/202501/t20250103_1099965.html

The IEA works with governments and industry on issues related to renewables, fossil fuels, energy efficiency, clean energy technologies, electricity systems, markets and access to energy.

The IEA has published some guidance on methane emissions and reduction opportunities at coal mines, including:

- *Driving Down Coal Mine Methane Emissions – A Regulatory Road Map and Toolkit* (IEA 2023a).

The IEA's Global Methane Tracker also provides country-level information on abatement potentials, mitigation technologies and coal mine methane emissions (IEA 2024).

3.4.6 Summary of guidance

Several of the more relevant guidance documents that were obtained from the literature search are summarised in Table 3.7. Some of the documents were not explicitly described as guidance, but were nevertheless considered to contain relevant information for the review. The table excludes legislation and policy documents from Australia and NSW.

It is worth noting that there is currently no comprehensive, publicly available best practice guidance on reducing GHG emissions from the NSW coal mining industry. Each document in the table has therefore been rated subjectively (between one and three stars), based on its coverage of a number of topics of relevance to the literature review. These topics include coal mining processes/activities, associated GHG emission sources, existing and emerging mitigation measures, GHG measurement methods, mitigation costs and mitigation case studies.

Each document was rated, very generally, on the amount of relevant content for the review. For example, a document with, say, a paragraph of relevant content would typically receive one star, whereas a document with half a page of content would receive two stars, and a document with several pages would receive three stars. The overall usefulness to the review of each document was also determined. Table 3.7 only contains the documents that were rated as either 'medium' or 'high' in terms of their overall usefulness.

These document in the table are mostly from international organisations, and do not generally provide NSW-specific context, or consider coal mining in NSW. However, much of the technical information is likely to be transferable. The focus is also on reducing emissions at coal mine sites; few of the guidance documents cover scope 2 or scope 3 emissions in any detail.

Table 3.7 **Summary of guidance documents**

Reference	Mining processes	GHG sources at mines	Existing measures	Emerging measures	GHG measurement	Costs	Case studies	Relevance to study
Crittenden et al (2016) Energy Management in Mining	«	–(a)	««	«	–	«	«	Medium Concentrates on energy efficiency.
UNECE (2016) Best Practice Guidance for Effective Methane Drainage and Use in Coal Mines	««	«	««	«	««	««	«««	High Detailed coverage of drainage, with multiple case studies.
USEPA (2018) Overview of SF ₆ Emissions Sources and Reduction Options in Electric Power Systems	–	–	«	–	««	–	«	Medium Only covers SF ₆ . Not specific to mining.
UNECE (2019) Best Practice Guidance for Effective Methane Recovery and Use from Abandoned Coal Mines	««	«	««	«	««	«	«««	High Detailed coverage of AMM, with multiple case studies. Useful information on AMM use.
USEPA (2019a) Ventilation Air Methane Utilization Technologies	–	«	««	««	–	–	««	High Brief. Focuses on technologies and case studies.
UNECE (2021) Best Practice Guidance for Effective Management of Coal Mine Methane at National Level	«	««	«	–	«««	«	««	High Concentrates strongly on monitoring, reporting and verification. Only covers CH ₄ .
Katestone (2023) Best Practice Checklist for Greenhouse Gas Abatement by NSW Coal Mines	–	«	««	««	–	–	–	Medium ^(b) Identifies some existing and emerging best practice in the main areas, but lacks detail. (e.g. does not mention gas-drainage).
FBICRC (2023) An overview of Australia's mining vehicle and mining equipment electrification	«	–	«	««	–	«	«	Medium Detailed information on electrification in mining. Not specific guidance on coal mining.

Reference	Mining processes	GHG sources at mines	Existing measures	Emerging measures	GHG measurement	Costs	Case studies	Relevance to study
IEA (2023a) Driving Down Coal Mine Methane Emissions	«	««	««	«	-	-	-	Medium Deals with the development of regulation. Only covers CH ₄ . Good links to resources and policies in various countries.
UNECE (2024) Best Practice Guidance on Ventilation Air Methane Processing	«	«	««	«	-	««	-	Medium Brief document. Some information on costs.
UNECE (2025) Best Practice Guidance on Ventilation Air Methane (VAM) Mitigation	«	«	«««	««	-	««	«««	High Good coverage of RTO (but no detailed technical specifications on different types of RTO). Contains several case studies.

Notes

- (a) ‘-’ = no significant coverage of topic.
- (b) Although the Katestone report is clearly relevant to the study, it does not (intentionally) contain much detail and has not been independently reviewed. It is therefore not referred to extensively in this review.

3.5 Resources

Some additional resources relating to GHG emissions from the coal mining sector are identified below. This list is not designed to be comprehensive, but provides links to tools, studies and other resources.

3.5.1 Global Methane Initiative

The Global Methane Initiative (GMI) is an international partnership of 42 member countries (including Australia, since 2004) and the European Commission that focuses on cost-effective, near-term methane recovery and its use as an energy source. Coal mining is one of the key sectors covered by the GMI, and the GMI web site contains a list of international CMM projects²³.

3.5.2 Coalbed Methane Outreach Program

The USEPA's Coalbed Methane Outreach Program (CMOP)²⁴ works with coal mines in the US and internationally to encourage the economic use of CMM. The work supports the goals and objectives of the GMI. An important element of the CMOP is the development of CMM pre-feasibility studies that provide a cost-effective step to project development and implementation by identifying opportunities through a high-level review of gas availability, end-use options and emission-reduction potential.

3.5.3 International Methane Emissions Observatory

The United Nations Environment Programme's International Methane Emissions Observatory (IMEO)²⁵ provides open-access data on methane to support emission-reduction projects, and supports the Global Methane Pledge. The goal of IMEO's scientific work is to address the gaps in the understanding of methane sources and emissions. The IMEO programme extends across all methane-emitting sectors.

Some main areas of IMEO's work include:

- Methane Science Studies
 - IMEO commissions scientific studies to provide strong, publicly available data and improved methods for measurement to allow governments, industry and other stakeholder to prioritise actions to assess and reduce methane emissions. The current focus is on the oil, gas and coal sectors.
 - To date, IMEO has published studies relating to coal seam gas production in the Surat Basin region of Queensland (e.g. Lu et al 2021; Neiningner et al 2021), and is funding ongoing studies in the Bowen Basin.
- Methane Alert and Response System (MARS)
 - MARS was launched at COP27. It is the first global satellite detection and notification system providing actionable data on very large methane emission sources, initially concentrating on the energy sector.

²³ <https://www.globalmethane.org/coal/index.aspx>

²⁴ <https://www.epa.gov/cmop>

²⁵ <https://www.unep.org/topics/energy/methane/international-methane-emissions-observatory>

- MARS has four main components:
 - Detection of large methane emission sources. MARS uses existing global mapping satellites (e.g. ESA Sentinel-5P TROPOMI) to identify very large methane plumes. Further analysis using other, higher-resolution satellites (e.g. ASI PRISMA, ESA Sentinel-2) and ancillary datasets enables attribution of the plumes at the facility level.
 - Notification of relevant countries and companies about the detected emissions.
 - Response from notified stakeholders to address the emissions.
 - Tracking progress of actions taken to reduce emissions and collaboration to prevent future methane emissions.
- MARS will incorporate new satellites as they come online to refine its ability to deliver actionable data.

IMEO also has an implementation program to raise awareness and increase the capacity of governments to pursue science-based policy options to manage methane emissions. This work includes training and working with relevant stakeholders on dedicated projects to reduce methane emissions.

3.5.4 International Council on Mining and Metals

The International Council on Mining and Metals (ICMM) is an industry body that promotes sustainable development in the mining sector. ICMM's Innovation for Cleaner, Safer Vehicles (ICSV) initiative involves some of the world's largest mining equipment manufacturers, and aims to accelerate the development of a new generation of mining vehicles.

The ICMM has published a framework for mining companies to calculate and disclose their GHG emissions, including scope 3²⁶.

3.5.5 Electric Mine Consortium

The Electric Mine Consortium (EMC)²⁷ operated between 2021 and 2024, and aimed to accelerate progress towards fully electrified mines. Its members included mining companies, equipment manufacturers, battery/storage providers, power systems operators, consultants and industry bodies.

3.5.6 FutureCoal

FutureCoal²⁸ (formerly the World Coal Association) is a global alliance of coal producers, consumers (e.g. power, steel, cement, aluminium, fertilisers), suppliers, governments and investors. At the time of writing, the FutureCoal web site provides little information on GHG mitigation for coal mines.

3.5.7 Minerals Council of Australia - Towards Sustainable Mining

In partnership with the Mining Association of Canada, the Minerals Council of Australia has adopted Towards Sustainable Mining (TSM), a globally recognised accountability framework which helps mining companies to evaluate, manage and communicate their site-level sustainability performance. The TSM framework supports consistent measurement and reporting, and improved transparency.

²⁶ <https://www.icmm.com/en-gb/news/2023/disclosure-scope-3-emissions>

²⁷ <https://www.electricmine.com/>

²⁸ <https://www.futurecoal.org/>

3.6 Existing GHG mitigation measures

This section describes the existing measures for reducing GHG emissions in the coal mining sector, taking into account the aspects mentioned in section 3.2. The section considers mitigation measures that are technologically mature and commercially available, even if there are still some barriers to implementation, and summarises their main characteristics. Any experience to date in NSW with respect to these measures, or more widely in Australia, is also highlighted.

The emphasis of the section is on reducing scope 1 emissions from coal mines, the majority of which are from fugitive and diesel combustion sources, and to a lesser extent scope 2 emissions. The review also identifies measures to reduce scope 3 emissions, noting that these are less easy to identify and implement than those for scope 1 and scope 2. The discussion of scope 3 measures is therefore brief.

3.6.1 Scope 1 emissions: fugitive methane

i Definition of methane mitigation

This section of the report deals with the treatment of fugitive methane, for which the boundary between unmitigated and mitigated emission sources is not clearly defined. As noted in section 3.2.2, gas drainage and mine ventilation are common practice with respect to safety management at underground coal mines. These processes cannot, in themselves, be considered to represent GHG mitigation where the resulting gas is vented directly to the atmosphere as a fugitive emission. However, the processes *are* part of a mitigation strategy when the gas is either treated at the point of release to the atmosphere (e.g. by flaring drainage gas) or captured for subsequent utilisation. Gas drainage and mine ventilation are therefore included in this section of the report. The potential uses of methane from mines are covered in section 3.8.

Box 4: What is a methane mitigation measure?

In this report, an intervention at a coal mine that follows the initial release of methane from a coal seam is taken to be a methane mitigation measure. However, mine ventilation and gas drainage can only be considered as elements of a mitigation strategy where the gas is either treated or captured for use.

Almost all methane mitigation measures have the same overall effect with respect to GHG emissions, and that is the oxidation of methane to CO₂. The oxidation process effectively reduces the GWP of the mine gas. This is true irrespective of whether the methane undergoes combustion in a flare, undergoes catalytic oxidation, or is captured and used to supplement natural gas supplies or generate electricity. Unless methane can be permanently sequestered (e.g. in materials), mitigation measures do not eliminate GHG emissions.

The comprehensive management of gases at coal mines is sometimes referred to as ‘integrated gas management’. This includes, for example, mine planning, gas drainage, mine ventilation and the use of methane in electricity generation. As the various elements that are relevant to GHGs are addressed separately in this literature review, the concept of integrated gas management is not considered further.

ii Active underground mines

The IEA estimates that it is technically possible to avoid more than half of global methane emissions from coal operations with existing technologies. Gassy underground coal mines (and in particular VAM) present the largest potential for mitigation, as they account for the largest share of emissions from the coal mining industry. However, given that the amount of methane in a given coal seam varies widely by location, there is no ‘one-size-fits-all’ approach to mitigation (Campey et al 2017; IEA 2023a). The various processes involved in the treatment of methane are reviewed below, starting with gas drainage and mine ventilation.

Methane is explosive in concentrations in air of between 5% and 15%. In-mine concentrations must therefore be maintained well below the lower explosive limit of 5%. Sufficient air must be provided to ensure that, in working areas of the mine, methane is diluted below specified limits, which are usually in the range of 1% to 2% to give a margin of safety. CSG is typically diluted and extracted using ventilation systems that include fans, airways and ventilation controls. Mines are ventilated by either exerting positive pressure to push fresh air through, or creating negative pressure to draw fresh air through. The fresh air is passed around the working areas to collect methane, and then exhausted at an upcast shaft (a vertical mine entry) or drift (an inclined mine entry). As a seam is progressively mined, the mine's ventilation system constantly monitors the level of methane, pumping in fresh air to ensure that methane levels remain below the limits (USEPA 2019a; UNECE 2021; Assan 2022).

Several gas drainage²⁹ methods are available for capturing CSG to prevent it entering the airways of underground mines³⁰. There are two main approaches to gas drainage in underground mines:

- **Pre-drainage.** In this approach, gas is extracted from the coal seam before mining begins. Horizontal boreholes are drilled into the coal seam from either within the underground mine workings (underground to in-seam, or UIS) or from the surface (surface to in-seam, or SIS). Gas then flows out of the coal seam under natural pressure through the boreholes into a pipeline collection system. This drainage process can also continue during the mining phase.
- **Post-drainage.** In this approach, vertical and/or horizontal boreholes are drilled into the mine workings, so that drainage can take place after the coal has been mined. The gas is then removed under suction.

Examples of these approaches are shown in Figure 3.4; the figure also shows the potential fate of the drainage gas. The complexity and effectiveness of drainage systems can vary significantly (Black and Aziz 2009).

The need for gas drainage at a particular mine depends on various factors, including gas content and composition, coal seam permeability, mining methods, geological conditions, safety and regulatory requirements, and economics. For example, drainage should be employed where gas flows exceed the capacity of the mine ventilation system to ensure adequate dilution of methane in the mine air (UNECE 2016).

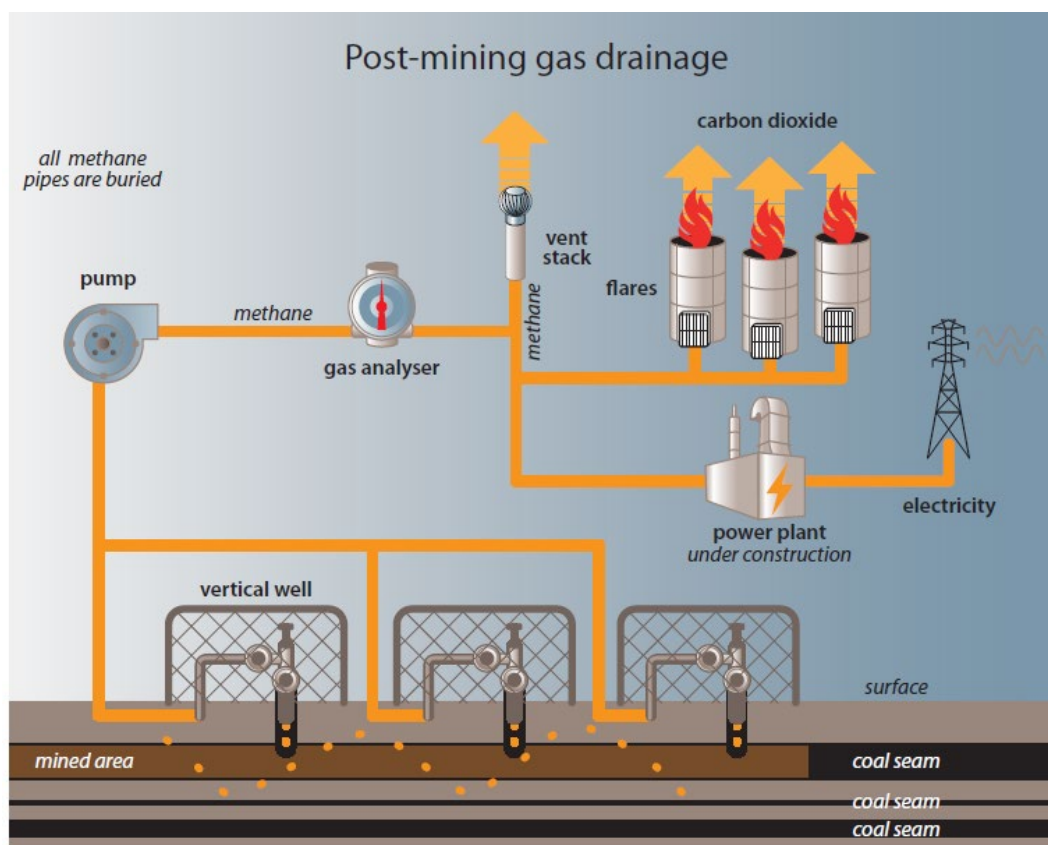
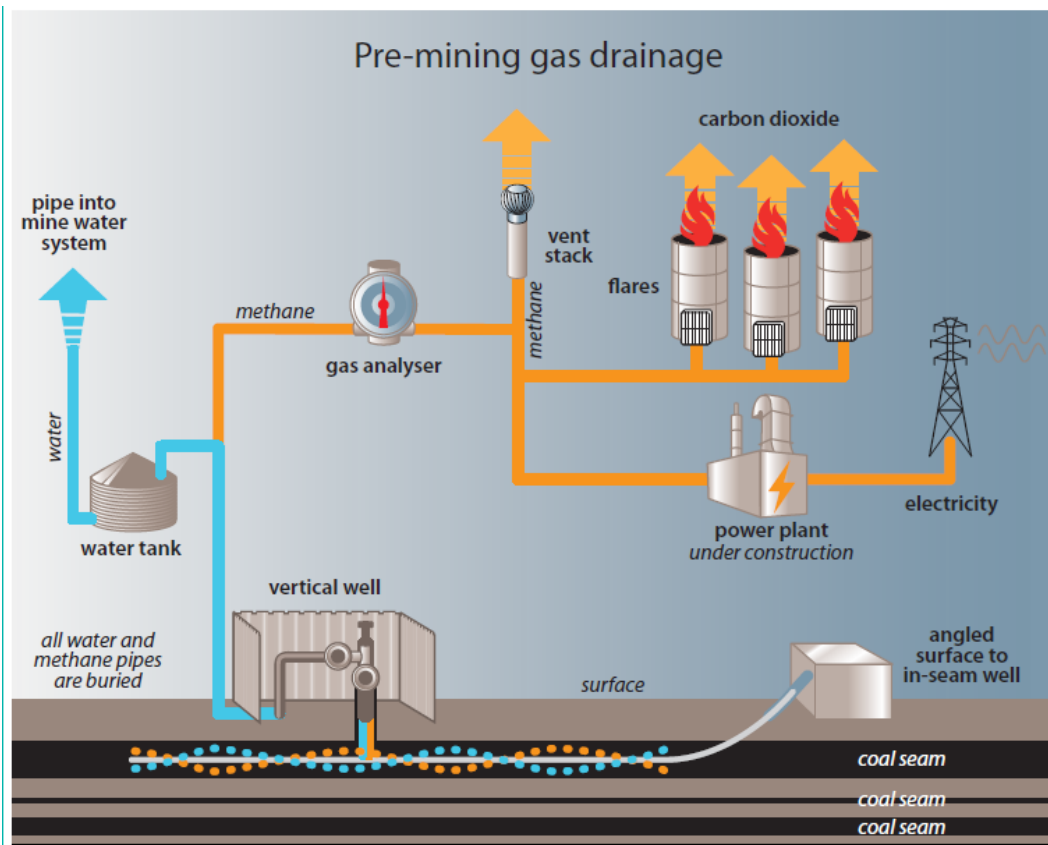
Pre-drainage represents the current best practice for gas management. It can produce methane that is suitable for subsequent use, but the viability of this (and the specific use) depends on the quality and quantity of gas in the coal seam. High-quality methane is recoverable from coal seams by drilling vertical or horizontal wells from the surface up to 10 years in advance of a mining operation, or drilling horizontal boreholes several months or years before mining. However overseas many mine operators exercise 'just-in-time' management for new operations, with horizontal cross-panel boreholes being installed to drain gas for six months or less (USEPA 2019b).

There are various safety issues associated with gas drainage. Spontaneous combustion may occur when the oxygen level in the drained gas exceeds 8% (NSW Government Industry & Investment 2011). However, pre-drainage gas typically contains less than 1% oxygen (Climate Action Reserve 2009). Post-drained gas can be of variable quality, and careful management is needed to minimise dilution by air to avoid the formation of potentially explosive mixtures. In oxygen-deprived environments, such as can occur in sealed goafs³¹, explosive mixtures can only form if air is added.

²⁹ Gas drainage is also referred to as mine degasification.

³⁰ Although the drainage of CSG from coal seams can be conducted for surface mines, it is more commonly conducted in underground operations for reasons including generally higher methane concentrations, safety, operational requirements and feasibility.

³¹ A goaf is broken, permeable ground where coal has been extracted by longwall coal mining and the roof has been allowed to collapse, thus fracturing the strata above (UNECE 2016).



Source: Glencore (2022a)

Figure 3.4 Examples of pre-drainage and post-drainage

Given that they are obtained using different approaches, ventilation air and drainage gas have different properties. Although their composition can be highly variable, some typical characteristics are:

- Ventilation air: <1% CH₄; ~20% O₂; <1% CO₂
- Pre-drainage gas: >60% (up to 95%) CH₄
- Post-drainage gas: >30% (up to 95%) CH₄

The ventilation air from an underground mine has a composition that is quite similar to the fresh air going into the mine, with around 80% nitrogen and 20% oxygen. Methane concentrations are typically less than 1%, and often less than 0.5%. According to Liu et al (2024), the concentration of methane in the air from the exhaust shafts at Australian coal mines is typically between 0.2% and 0.4%. However, because the exhaust flow rates are high (in excess of 500 m³/s), absolute methane emissions from ventilation shafts can also be very high (USEPA 2019a; UNECE 2021; Assan 2022; UNECE 2024).

Untreated VAM or drainage gas can be vented directly to the atmosphere as a fugitive emission source. However, this is undesirable because methane is a potent GHG. Therefore, technologies that destroy the methane, or capture and convert it into useful forms of energy (such as electricity and heat) can yield substantial GHG emission reductions as well as economic benefits. However, the treatment of VAM is considered to be particularly challenging. As noted above, the volume of ventilation air is large and the methane concentration can be very low; the lower the concentration of methane, the more technically and economically difficult it is to treat (IEA 2023a). Another factor that could influence the development and selection of VAM treatment technology is the dust concentration in the air (Rahimpour 2023). For example, airborne dust could potentially affect the performance of oxidation technologies, and specifically those that employ a catalyst.

The concentration of methane in drainage gas is variable. It ranges typically between 30% and 60%, but can be much higher (UNECE 2024). For pre-drainage, methane concentrations of 60% and higher should be achievable, whereas for post-drainage methane concentrations of 30% and higher should be achievable in all but the most challenging mining conditions (UNECE 2021).

The existing technologies for treating VAM and drainage gas are discussed below. The utilisation of drainage gas is covered as a separate topic in section 3.8.

b Drainage gas flaring

Flaring refers to the process of burning methane in a flame. Where there is no feasible use of the methane from a coal mine, flares can be used to reduce its climate impact (IEA 2023a). VAM usually has a very low concentration of methane (often less than 1%). Because the lower flammability limit of methane is around 5%, conventional flaring of VAM is not possible unless a supplementary fuel is used, and this is likely to be uneconomical. On the other hand, drained mine gas typically has a relatively high methane concentration (this is one reason why drainage is conducted in the first place), meaning that it can potentially be combusted using a flare.

The technology used for flaring needs to be capable of handling the specific flow rates and concentrations of methane. The main methods are:

- Open flaring. This involves burning methane in an open flame. It is generally the simplest and cheapest approach, being easy to install and maintain, and can handle large volumes of gas. However, it can be harder to control, with less efficient combustion, than other approaches, resulting in emissions of unburned methane. Open flares can be operated safely for methane concentrations down to around 20%, but typically require a minimum methane concentration of about 30% (UNECE 2024).
- Enclosed flaring. These systems burn methane in a controlled, enclosed environment, which improves combustion efficiency and reduces methane emissions. However, enclosed systems are more complex and expensive than open flares.

The choice of technology depends on the methane concentration, regulatory requirements, safety and economics. The decision to flare also involves practical considerations such as the availability of flare systems, operational costs and the impact on overall mining operations.

Flares can achieve a methane destruction efficiency of greater than 99% (UNECE 2024); some methane can escape as a result of incomplete combustion.

According to CSIRO (2024), the cost-effectiveness for flaring of drainage gas from coal mines in Australia is \$0.2 per tonne of CO₂-e. This assumes that 75% of all methane in current drainage gas is flared.

Box 5: Experience of flaring in Australia

Gas flaring is used at some coal mines in Australia. Qu (2024) has estimated that there are currently eight Australian coal mines that use flaring to manage methane emissions. Coal mines that have flares include Bulga, Ashton, Appin, Mandalong and Tahmoor (Figure 3.5) in NSW, and the Oaky Creek and Moranbah mines in Queensland. Flaring is also being considered at other mines.



Source: Eneraque (2024)

Figure 3.5 Tahmoor gas flare facility

c Thermal oxidation

The full mitigation of VAM emissions requires equipment that can process the entire volume of air exiting the mine, but this may not be necessary. For example, the processing of more than 95% of the ventilation air would be acceptable if it helps improve safety management through an unenclosed ducting. So far, a technology known as regenerative thermal oxidation (RTO)³² is the only one that has been successfully used for the large-scale processing of VAM as a primary fuel. Most VAM technologies *other than* RTO have not gone beyond the lab or pilot phase (UNECE 2024). Some other approaches that have been investigated are discussed in section 3.7.

³² Also known as Thermal Flow Reversal Reactors (TFRR).

RTO technology was developed in the 1970s, and many RTO plants have been installed in various industries around the world, mainly for the destructions of volatile organic compounds (VOCs). RTO for the processing of VAM was developed in the 1990s, and commercialised at the start of the 21st century. The first commercial implementation of a VAM RTO project was in 2007 in NSW.

RTO involves oxidising the methane in air (i.e. methane reacts with O₂) at high temperatures (e.g. 850 to 1,200°C) in a flow-reverse reactor. The reactor transfers the heat generated by the oxidation process to a solid medium, and back to the incoming air to raise its temperature to the ignition temperature of methane. The process can be self-sustaining without requiring additional fuel input when the VAM concentration is above its minimum concentration requirement.

According to the specifications of commercially available RTO systems, a methane concentration above (typically) 0.2% is required to maintain the methane oxidation, and RTO can handle variable concentrations. The operational range of methane concentrations would be different for each type of RTO. Some systems have a maximum methane concentration for VAM processing of around 0.7%. Other designs can operate up to 1.2%, but may need to be integrated with a heat extraction system to maintain acceptable operational temperatures (USEPA 2019a; Rahimpour et al 2023; UNECE 2024; UNECE 2025). Liu et al (2024) state that RTO systems cannot efficiently process ‘very dilute’ VAM streams, which may be problematic at some Australian mines.

RTO can be energy-intensive, depending on its design. As well as the safety issues relating to the potential for explosion (i.e. flashback into a mine during its gas outburst), consideration also needs to be given to the safety risk associated with connecting a high-temperature process to a mine outlet.

As safety remains an area of concern to the industry, an area for future analysis could be an investigation into RTO units that have been trialled or operated at coal mines across Australia and in other jurisdictions. This analysis could focus on safety management at RTO plants, but also consider if there have been any reported safety incidents. This analysis could be done in the context of the safety expectations at NSW coal mines (e.g. safety integrity level (SIL) rating).

The lifetime of an RTO plant is typically around 20 years, but the life of the mine itself may be the limiting factor. However, if key elements of the VAM mitigation plant are designed in a modular way, they might be disassembled and relocated (UNECE 2024).

The investment cost for VAM processing relates mainly to the volume of ventilation air that needs to be processed, and to a much lesser degree on the methane concentration. Therefore, higher-concentration shafts not only produce more emissions, but are also characterised by lower mitigation cost per unit emission unit (UNECE 2024).

An indicative cost-effectiveness for VAM abatement via RTO is \$12 to \$20 per tonne CO₂-e (CSIRO 2024; Deloitte 2024). For Australia, CSIRO obtained the value of \$12 per tonne of CO₂-e for RTO applied to VAM in the 0.4-0.6% concentration range, with an effectiveness for methane abatement of 75%. The value of \$20 per tonne of CO₂-e obtained by Deloitte for NSW was based on the deployment of RTO at seven NSW underground mine sites, with each site capturing 93% to 100% of methane. It was also assumed that all RTO assets would gradually be retired during the 2040s.

Box 6: Experience of RTO in Australia

In Australia, there have been RTO demonstrations projects, but not widespread adoption of the technology. There are only two RTO installations, both at the Appin Coal Mine in NSW. The main barriers to the wider adoption of RTO in Australia appear to be capital expenditure and safety (KPMG 2021; CCA 2024).

CSIRO has been working on VAM abatement technology for more than 20 years, and has developed a technology called VAMMIT (Ventilation Air Methane Mitigator), which can be operated as either a thermal (RTO) version or a catalytic version. Site trials of VAMMIT using actual ventilation air were successfully carried out at Appin (Figure 3.6). The thermal version destroyed $\geq 0.3\%$ methane in air with a significantly lowered pressure drop and power consumption. On average, more than 96% of the methane was oxidised. The influence of dust in the ventilation air on the system's performance was found to be negligible (USEPA 2019a).

In July 2024 the Australian Government provided \$37 million of funding to implement full-scale RTO to treat VAM at the Kestrel Coal Mine in Queensland.



Source: Photograph courtesy of CSIRO

Figure 3.6 Trial of CSIRO's VAMMIT technology at Appin Coal Mine

iii Active surface mines

No existing measures for addressing fugitive methane emissions from active surface mines were identified. There are generally fewer opportunities for gas drainage at surface mines due to the more diffuse nature of fugitive methane emissions, and it is considered to be an emerging technology (see section 3.6).

According to the Climate Change Authority, the technical challenges in relation to draining methane from surface mines include lower gas concentrations, draining multiple seams of varying thickness, and longer drainage times required ahead of mining compared with underground coal mines (CCA 2024). The CCA also notes that drainage is especially difficult for established mines, where the integration of gas drainage and handling is likely to lead to mine planning and other operational challenges. For example, the effectiveness of drainage can be hampered by continuous mining operations along a coal face (Johnson 2024). Another factor that has worked against the uptake of drainage at surface mines in Australia is the absence of guidelines. In NSW, gas reservoir properties also make it technically difficult and expensive to extract methane.

Although open-cut coal mines report their fugitive methane emissions under the NGER scheme, they are not currently required to address them as there is no best practice to follow. Pressure to reduce GHG emissions could drive greater development in pre-drainage at surface mines in the future.

Box 7: Experience of drainage for surface mines in Australia

There is limited understanding of the potential application of gas drainage systems to surface coal mines in Australia, including the efficacy, cost and realistic timeline of implementing such systems (CCA 2024).

iv Closed underground mines

a Mine flooding

The most effective way to reduce emissions from a closed³³ mine is to allow natural mine flooding, which stabilises the hydrostatic pressure on the coal seams. Groundwater will, in many instances, progressively flood the mine and curtail emissions, and methane releases can ultimately be reduced to almost zero. However, depending on the hydrogeology of the area and local mining conditions, mines can take from a few years to decades to completely flood, and over this time a significant amount of gas may escape. There are also cases where flooding is not feasible due to the prevailing geological or climatic conditions. To avoid emissions during flooding, drainage systems can be put in place to ensure that any emerging gas is captured. The risk of acid mine drainage also needs to be considered, as this can contaminate nearby aquifers and subsoil (UNECE 2021; IEA 2023a).

b Mine sealing

Mines going through the decommissioning and closure³⁴ process in NSW have regulatory obligations that include sealing to remove ventilation³⁵. Ventilation shafts and other openings can be filled with gravel or concrete, but methane may still migrate through unsealed entries or poorly sealed shafts, as well as through cracks and fissures in the overlying strata. Measures can be put in place to ensure that any gas from sealed mines is captured, such as pressure-relief vents. However, these measures are not widely deployed at present. In many instances, there are uncontrolled leaks from shaft and drift seals, outcrops, fractured ground above shallow workings, or through underground connections with old workings of other closed mines. The sources of such emissions can be difficult to locate and, in some cases, can affect extensive areas (UNECE 2021). According to IEA (2023a), new policies and regulations are needed to address emissions from closed mines.

³³ Flooding may begin to occur naturally where mine operations have been suspended.

³⁴ Areas of an active mine that are no longer required can also be sealed.

³⁵ In NSW, Schedule 3, Clause 2 of the *Work Health and Safety (Mines and Petroleum Sites) Regulation 2022* states that mine sealing is a 'high risk activity', and requires identification and control of hazards, including methane content.

The handling, processing and transport of coal can cause methane trapped in the matrix of the coal to be released. However, the abatement pathways for these activities are not well understood at present (IEA 2023a).

Some measures can be applied to coal stockpiles, although controlling fugitive methane remains a challenge. Existing management practices include the following:

- Minimising coal handling. Reducing the frequency of coal handling can reduce the possibility of methane being released.
- Covering/sealing. Impermeable covers and seals can potentially be used on coal stockpiles, and where long-term storage is likely this can reduce and delay the release of gases. However, gases may be released following the removal of covers. This approach is also unlikely to be practical for active stockpiles.

3.6.2 Scope 1 emissions: diesel combustion

The existing measures for reducing GHG emissions from diesel combustion are broadly applicable to all mine types and stages, although they are most relevant to the active stage of mining. These measures are discussed below.

i Mine planning and operation

Mine planning is an important tool for maximising operational efficiency (process optimisation), and hence minimising energy/diesel consumption and GHG emissions. In this context, mine planning currently involves the following:

- Planning and scheduling operations to minimise material handling, equipment operating hours and fuel burn.
- The design of loading, transit and unloading areas to minimise unnecessary slowing or stopping of haul trucks.
- Designing haul routes to minimise energy consumption, such as reducing route lengths, reducing gradients, and avoiding unnecessary stops.
- Optimising payloads (e.g. filling haul trucks to optimum amounts). If trucks are underloaded, more diesel is needed to transport the total payload. If trucks are overloaded, the diesel consumption of each truck increases (in addition, truck warranties may become void and maintenance costs increase due to additional wear and tear). Payload management ensures that each haul truck carries the optimal amount of material to maximise overall fuel efficiency. In some cases, this approach can also reduce the number of trucks needed in the fleet (Campey et al 2017; Crittenden et al 2016).
- Haul road management, including regular maintenance to ensure that gradients and rolling resistance are minimised.
- Minimising engine idling for vehicles and equipment where possible, with the support of driver training.

ii Fleet planning

Campey et al (2017) noted that the use of larger, more efficient diesel haul trucks can reduce the amount of fuel required per tonne of material hauled. Haul truck fleets can therefore be structured during procurement to minimise energy consumption. Another option is to use lighter components, such as lightweight tray liners (Crittenden et al 2016).

iii Energy-efficient vehicles and equipment

The procurement of conventional – but more fuel-efficient – mine vehicles and equipment where practicable, and considering the technology options, is an important element of mine operations, and one that should help to reduce GHG emissions and costs before alternative technologies become available.

NSW EPA intends to place conditions on all coal mine licences that will require all new large (>560 kW) non-road diesel machinery to meet the USEPA Tier 4 emission standards (or better) (NSW EPA 2023b). An important justification for this is the impact of non-road diesel emissions on health. Emissions of particulate matter with a diameter of less than 2.5 µm (PM_{2.5}) and oxides of nitrogen (NO_x) from non-road diesel engines are a major concern, and coal mining is the largest contributor in NSW. A recent cost-benefit analysis for the Australian Government (Boulter et al 2022) showed that non-road diesel engines contribute significantly to the health burden of air pollution, and the mandating of Tier 4 standards would have a large economic benefit due to a reduction in this burden.

Although the focus of the EPA's approach is on health, it would also have co-benefits in relation to climate. In particular:

- diesel emissions contain short-lived climate pollutants (e.g. black carbon). It is important that emissions of these pollutants are reduced in the near future³⁶
- the EPA will strongly encourage licensees to seriously consider investing in non-diesel options, such as hydrogen fuel cells and electric vehicles and equipment, when they become available.

iv Servicing and maintenance

Regular maintenance of diesel vehicles and equipment according to manufacturers' specifications is required to ensure that their performance does not deteriorate over time. Fuel efficiency can be adversely affected by, for example, incorrect fuel injector timing and oil filter blockages. Further improvements could potentially be achieved if maintenance is triggered by monitoring of vehicle performance and driver behaviour. Another maintenance measure involves pre-start inspections on vehicles and plant at the start of each shift.

v Driver training

Coal mines generally carry out training of staff to raise awareness of fuel efficiency (and hence GHG emissions). Improved driver practices, or 'eco-driving', refers to an approach in which the driver achieves optimal fuel economy. The system incorporates a range of driving behaviours, such as smooth driving (gentle acceleration and braking), driving more slowly, and less idling. In simulator trials for haul trucks this led to a small reduction in diesel consumption (2%) (Crittenden et al 2016).

vi Biodiesel

Replacing fossil fuels with biofuels can potentially help to reduce GHG emissions from coal mining. A biofuel is a fuel that is derived from biomass over a short time period, rather than by the very slow natural processes involved in the formation of fossil fuels.

Biodiesel has been available as an alternative to fossil diesel for several decades. It is produced from oils or fats from through an esterification process, creating fatty acid methyl esters (FAME). Plant feedstocks for biodiesel include vegetable oils, soy, rapeseed, sunflower and palm oil.

³⁶ The fuel consumption benefits of Tier 4 engines compared with older technologies are likely to be relatively small. For example, Boulter et al (2022) assumed that replacing on pre-Tier 4 engine with a Tier 4 engine would reduce fuel consumption by 2%.

Biodiesel is chemically different from fossil diesel, and cannot generally be used as a direct substitute at a high blend ratio without affecting engine operability. Biodiesel also has a high oxygen content, which can present some problems with long-term storage. For these reasons, biodiesel is usually only blended with fossil diesel in small amounts (DCCEEW 2023d). The *Fuel Quality Standards (Biodiesel) Determination 2019* regulates the quality of biodiesel in Australia, and the *Fuel Quality Standards (Automotive Diesel) Determination 2019* limits the biodiesel content of diesel to 5%. This is generally the maximum blend rate that is suitable for light-duty diesel vehicles. DCCEEW is currently investigating biodiesel/diesel blends for industrial heavy-duty diesel engines.

Other barriers to the widespread application of biodiesel in the mining industry are the lack of supply of suitable quantities, and its higher cost relative to fossil diesel. Where it is used at coal mines, biodiesel is likely to represent an interim measure as electrification develops (Advisian 2022).

Another potential alternative fuel is renewable diesel, which is considered as an emerging measure in section 3.7.2.

vii Fuel additives

Some mines are considering the use of aftermarket diesel additives to improve fuel efficiency. Many different additives are on the market, with purposes that include improving low-temperature operability (e.g. flow improvers), fuel stability (e.g. antioxidants), engine protection (e.g. corrosion inhibitors), and combustion (e.g. ignition improvers, combustion catalysts).

Given the wide range of additive formulae available, and the lack of rigorous testing across a wide range of vehicle types and operational conditions, it can be hard to understand the likely real-world effects of a given product. The performance claims of the supplier may not be achieved in practice, and studies in the scientific literature have often concluded that additives have no significant effect on fuel consumption. It is also worth noting that the USEPA has been testing fuel additives for many years, and maintains a register of suppliers and products³⁷.

Jääskeläinen and Richards (2020) argue that, in most cases, additives are not needed, especially for modern diesel engines, and that good quality commercial fuel contains all the components required and have been extensively tested to minimise adverse effects on engines and operation.

It is likely that, on balance, the effects of additives on fuel efficiency (either positive or negative) will be small, and products should be chosen and used with caution.

viii On-site renewable energy

Diesel generators may be used at remote coal mines where connecting to the grid is not possible, during construction, or for emergency purposes. In such cases, GHG emissions from diesel combustion can potentially be mitigated through the use of small-scale on-site renewable energy (e.g. solar/wind power).

3.6.3 Scope 1 emissions: other minor sources

i Petrol combustion

Because petrol use is a relatively small contributor to GHG emissions at NSW coal mines, it tends to receive little attention in terms of GHG mitigation. Where appropriate, petrol vehicles and equipment can be replaced over time with electric equivalents.

³⁷ <https://www.epa.gov/fuels-registration-reporting-and-compliance-help/registered-fuels-fuel-additives-under-part-79>

ii ANFO combustion

Goswami (2016) discussed several developments in blasting techniques that could potentially reduce the GHG emission intensity of coal extraction from surface mines. These developments would not necessarily reduce absolute GHG emissions, but would facilitate the recovery of more coal from the same amount of blasting. However, the blasting strategy can potentially be optimised to minimise the movement of equipment and rehandling of material, thus reducing energy consumption. Similarly, a review by CSIRO (Campey et al 2017) noted that high-intensity and selective drilling and blasting could reduce energy use by minimising the amount of material handled, and the energy required, during a mining operation.

iii Oils and greases

The use of oils and greases is another minor source of GHG emissions at coal mines. Existing mitigation measures include recycling and the use of 'bio-lubricants' or additives which are made from renewable resources, such as plant-based oil, instead of petroleum. The increased electrification of mine vehicles and equipment may also lead to a reduction in the consumption of oils and greases.

iv Fugitive SF₆

According to USEPA (2020), while non-SF₆ equipment has long been available for low-to-medium voltage³⁸ applications, alternatives for high-voltage equipment are at the early stages of entering the market. In general, as the market for SF₆-free equipment matures and adoption accelerates, the barriers to new technology can be expected to come down. In the meantime, best practice pays attention to the responsible management of SF₆.

Further guidance on SF₆ management has been provided by USEPA (2018):

- Operating procedures. Company documents and procedures can establish a lifecycle approach to SF₆ management.
- Gas accounting and tracking. Procedures and systems for gas accounting, tracking and management can monitor all SF₆ activities, such as purchases, cylinder rentals and recycling. Tracking the leak history of equipment creates awareness and allows the prioritisation of equipment repair or replacement.
- Training. Training is important for managing SF₆ emissions. Employees should be specifically trained in SF₆ handling and using equipment. Practices include not allowing SF₆ cylinders to be dropped or rolled, not applying direct heat, and prohibiting cylinder temperature to exceed 50°C.
- Recycling. The recycling of SF₆ reduces the overall amount vented to the atmosphere.
- Leak detection and repair (LDAR). LDAR is a vital to managing SF₆ emissions. Simple leak detection methods for SF₆ include soap and water solutions and bagging. In bagging, plastic lining is taped to sections of switchgear to trap any escaped gas. After several hours a standard leak detector can be used to measure any SF₆ under the plastic. More sophisticated techniques include thermal imaging cameras that exploit the infrared absorption of SF₆, and can detect minor, chronic leaks without the need to take equipment out of service. Equipment should be tested for SF₆ leaks before and after repairs.
- Equipment upgrade and replacement. Upgrading and replacing equipment can significantly reduce the quantity and frequency of SF₆ leakages.

³⁸ In the United States, electrical systems are classified as follows: <1 kV = low voltage; 1-100 kV = medium voltage; 100-230 kV = high voltage; 230-1,000 kV = extra-high voltage; >1,000 kV = ultra-high voltage.

v Coal oxidation

Heat accumulation and an oxygen source encourage low-temperature oxidation and spontaneous combustion (Zhang 2013). Existing management practices to reduce oxidation in stockpiles include:

- covering and sealing stockpiles to reduce exposure to air
- applying dust suppressants
- introducing microbial or biochemical agents to stabilise coal
- spraying with water to cool down coal
- controlling the size and shape of stockpiles.

Regular monitoring of the coal temperature in stockpiles can be used to detect signs of spontaneous combustion. Operational coal mines will generally have a formal spontaneous combustion management plan.

vi Vegetation removal

Current best practice strategies to reduce GHG emissions from vegetation removal include:

- avoiding or minimising vegetation clearing as far as practical through planning
- re-use of the removed vegetation (e.g. mulching or composting) to avoid rapid decomposition or burning. Whilst mulching or composting may still result in GHG emissions, the release of emissions will be slower and co-benefits include improved soil health and plant growth, resulting in increased CO₂ sequestration
- rehabilitation of land (especially with native plants) as quickly as possible, and progressively during construction and operations. There are also significant co-benefits of rehabilitation, including the reduction of dust and improving biodiversity.

Whilst not an on-site GHG mitigation measure, additional actions such as tree planting (off-site) and investing in reforestation carbon offsetting projects may be undertaken. Longer-term land use plans and post-mining land rehabilitation will improve carbon sequestration in cleared areas. Coal mines may be able to claim credits for reforestation and planting under the ACCU Scheme. However, specific conditions apply, and this is not considered as a priority measure for the reduction of GHG emissions.

3.6.4 Scope 2 emissions

With the trend towards mine electrification, scope 2 emissions could become a more significant component of a mine's overall GHG emissions. The GHG emission from a given mining process depends on the amount of electricity used by the process and the emission intensity of the electricity source. Existing measures to address scope 2 emissions therefore include reducing electricity consumption on-site, and/or reducing the emissions intensity of the electricity source.

i Energy efficiency

The most significant consumers of electricity at a coal mine are material conveying/processing and ventilation (underground mines). The Australian Government³⁹ identifies the following measures for reducing electricity consumption:

- The use of variable-speed drive (VSD) technology to control the speed and torque of motors to match the load (e.g. conveyors, material sizers), which can significantly reduce energy consumption.
- Reducing the area to be cooled by ventilation. Fan and pumping energy losses are often high due to the long distances over which air and chilled water must be transferred.
- The use of high-efficiency air conditioners, fans (including ventilation in underground mines) and pumps.
- Ventilation system maintenance improvements. Fan impellers or blades should be regularly cleaned to avoid fouling, which causes static pressure losses.

The energy used in mine-site buildings is usually only a small proportion of overall energy consumption, but energy-efficiency measures for buildings can demonstrate a commitment to reducing GHG emissions. The measures involved are typically relatively inexpensive and straightforward, such as designing buildings to reduce the need for heating or cooling, using energy-efficient appliances, installing timers on air conditioning units and lights, using solar power, and replacing incandescent and mercury vapour lights with light-emitting diode (LED) technology (Crittenden et al 2016).

ii Renewable grid electricity

Purchasing electricity generated renewably, rather than from fossil fuels, will reduce the scope 2 emissions from a mine site.

One mechanism for this is a Power Purchasing Agreement (PPA) for renewable electricity. A PPA is a contract between an energy buyer, such as a mining company, and an energy seller, usually a project developer (a wholesale PPA⁴⁰) or electricity retailer (a retail PPA). It is a contract for a fixed-price and fixed-supply of renewable energy, making it cheaper for businesses to use. A PPA guarantees that a mining company can purchase energy from renewable energy projects like off-site solar farms or wind farms for an agreed price, volume and term. NGERs allows renewable PPAs to be reflected in the reporting of scope 2 emissions.

Another mechanism is the surrender of large-scale generation certificates (LGCs). Under the Australian Government's Large-scale Renewable Energy Target (LRET)⁴¹, LGCs are a financial incentive for the generation of renewable energy from a power station. LGCs are tradable certificates created for eligible large-scale renewable energy power stations. An LGC is equal to 1 megawatt-hour (MWh) of renewable electricity generated or displaced by a power station. Many NSW coal mines are large users of grid electricity and have obligations to surrender a certain number of LGCs each year to meet their obligations under the LRET⁴².

The future electrification of NSW coal mines will be supported by the development of Renewable Energy Zones (REZs), which are intended to encourage investment in renewable generation and storage projects. The REZs will introduce wind and solar power generation at locations where it can be efficiently stored and transmitted across NSW. The NSW Government is currently committed to the development of five REZs in the state. However, the REZs will not start to operate before the late 2020s.

³⁹ <https://www.energy.gov.au/business/sector-guides/mining>

⁴⁰ Available to organisations with high energy consumption (over 60 gigawatt-hours per year (GWh/y)).

⁴¹ <https://cer.gov.au/schemes/large-scale-renewable-energy-target>

⁴² <https://cer.gov.au/schemes/large-scale-renewable-energy-target>

3.6.5 Scope 3 emissions

Scope 3 emissions occur outside the boundary of an organisation, and are generated in the wider economy. They are therefore largely beyond the control of mine operators. Consequently, the coverage of measures here is limited to identifying potential opportunities for reducing scope 3 emissions.

Examples of such opportunities include the following:

- Sustainable procurement practices. These include agreements with suppliers to improve practices and reduce their own GHG emissions.
- Contributing to research and development. This would include, for example, support for the development of low-emission technologies.
- Improving transport efficiency. Measures here include agreements with suppliers and end users to implement sustainable transport policies and technologies, such as electric vehicles and renewable electricity supplies.
- Reducing embodied carbon. The construction of new buildings and infrastructure is a major contributor to global GHG emissions through embodied carbon. GHG emissions occur as a result of material extraction, manufacturing and transport, construction, maintenance, demolition and disposal. The requirement for materials with a low-carbon footprint can be built into procurement policies. The coal mining industry also has the potential to support non-energy markets for its coal and waste materials, such as producing asphalt from coal and converting waste into construction materials.
- Coal combustion. Scope 3 emissions from the combustion of exported coal are not accounted for in company, NSW or Australian emission inventories. There is an opportunity for mining companies to help their international customers to reduce their emissions. This includes identifying if emissions are expected to be generated in countries that are signatories to the Paris Agreement or otherwise have policies that are consistent with the objectives of the Paris Agreement (NSW EPA 2024a).
- Coal stockpile management. The management of coal stockpiles by end users and intermediates should be conducted according to best practice.
- Understanding the full life-cycle emissions of coal mining, including exploration, mining, processing, refining, use and disposal.

3.7 Emerging GHG mitigation measures

This section reviews the emerging measures for reducing GHG emissions in the coal mining sector. It considers technologies that might soon be available, and are expected to be practically and commercially viable, but currently face significant barriers to uptake.

3.7.1 Scope 1 emissions: fugitive methane

i Active underground mines

It was identified in section 3.6.1 that, at present, the only practical treatments for methane from underground mines are flaring of drainage gas and RTO for VAM. Some emerging alternative treatments are summarised below.

a Catalytic oxidation

One potential approach for treating VAM is catalytic oxidation. Catalytic technologies are often referred to as regenerative catalytic oxidation (RCO), and are also known by the term catalytic flow reversal reactors (CFRR). In catalytic oxidation, the VAM is passed over a catalyst that is typically composed of precious metals such as platinum and palladium, which promote the oxidation of methane to CO₂. This accelerates the reaction between methane and oxygen at lower temperatures (e.g. 350 to 650°C) than thermal oxidation, and means that catalytic systems can operate at lower VAM concentrations. However, the catalysts are expensive (Rahimpour et al 2023; Liu et al 2024), and further research and development is needed to make catalytic technologies viable on a commercial scale.

Box 8: Experience of RCO in Australia

Pilot-scale trials of a modified (catalytic) version of CSIRO's VAMMIT system at the Appin Coal Mine in NSW were reported by Liu et al (2024). The catalytic VAMMIT demonstrated its high efficiency in eliminating low levels of VAM, successfully down to 0.1% methane, in a self-sustaining mode at substantially lower reaction temperatures, higher VAM flow rates and lower pressure drop compared to the former thermal-version VAMMIT. However, it was challenging for catalytic VAMMIT to process methane concentrations above 0.3%, as excessive reaction heat generated from the oxidation could not effectively be removed from the catalyst bed.

CSIRO has also developed a system called VAMCAT which uses a catalytic combustion gas turbine to oxidise methane and generate electricity¹. According to CSIRO, VAMCAT can be operated with methane concentrations of less than 0.3%.

b Methane enrichment

It is possible to enrich medium-quality gas to pipeline standards (see Table 3.8) using technologies that separate methane from CO₂, oxygen, and/or nitrogen. Several technologies for separating methane are under development, such as cryogenic separation and adsorbents. This technology would have implications for gas use, since there are more options for using high-concentration methane than typical drainage gas. These uses are discussed in section 3.8.

At the methane concentrations in VAM, the enrichment technology is not yet commercially available, and is expected to be expensive and limited in scope. It is argued by UNECE (2019) that the process is unlikely to be commercially viable in many countries.

Box 9: Experience of methane enrichment in Australia

CSIRO has developed a technology known as VAMCAP. The system uses carbon composite adsorbents to capture and concentrate methane from a mine ventilation system, enabling the recovery and use of the VAM. VAMCAP can be used to enrich methane to a concentration of 25% to 30%. However, the energy consumption and practical applicability would be major barriers at mines.

c Other methods

Some other methods have been investigated for controlling fugitive methane emissions. Further research and development is needed to understand the viability of these technologies for coal mines in NSW.

These methods include:

- Barriers. Johnson (2024) has proposed the use of impermeable underground barriers to reduce emissions from underground and open-cut coal mines in the Bowen Basin region of Queensland. These are based on the principle that naturally occurring barriers (e.g. faults) have been shown to effectively separate areas of drained and undrained coal.
- Biofiltration. This method uses microorganisms to biologically oxidise methane at ambient temperatures, converting it into CO₂ and water. Biofiltration is a potentially safe and inexpensive method for treating low methane concentrations (Limbri et al 2014).

ii Active surface mines

Gas drainage is an emerging measure for addressing fugitive emissions from active surface mines. UNECE (2021) notes that it has been achieved at some mines in the United States, but adds that few commercially viable applications have been reported globally, and it is not generally considered viable in most countries. UNECE (2016) summarises the general approach at surface mines, where boreholes can be used to drain the coal seam prior to the start of excavation, but they must be placed so that they remain undisturbed by mining activities and drilled sufficiently prior to the advance of mining to allow for effective drainage.

As noted earlier, there is little information on the application of gas drainage systems to surface coal mines in Australia. It may be feasible at some surface mines in NSW, but its suitability needs to be established on a case-by-case basis.

iii Closed underground mines

Few emerging measures for addressing fugitive emissions from closed underground mines were identified. However, some mines are considering the use of active flooding.

Flaring is a potential option for treating methane at mines that are being decommissioned or closed, although it is not widely practiced (UNECE 2019, 2021). As noted earlier, the potential ingress of air to goafs (to avoid potentially explosive mixtures) will be an important safety consideration. Before a decision is made to use flaring, it is important to properly assess the concentration and flow rate of methane. The likely duration of the methane release after mine closure should also be considered when assessing costs.

iv Post-mining

Few emerging measures for addressing fugitive emissions from coal stockpiles were identified. Stockpiles could potentially be stored in enclosed structures, with systems used to capture methane for subsequent utilisation. Monitoring systems could also be used to understand methane emissions and to inform the gas collection approach. A company called Geometrica has installed coal storage 'domes' at several overseas locations⁴³, and an example of such a system is shown in Figure 3.7.

⁴³ <https://www.geometrica.com/en/bulk-subsection-english>



Source: Photograph courtesy of Geometrica Inc.

Figure 3.7 Example of enclosure for coal stockpiles

The rationale for installing these structures currently relates to reducing material spoilage and environmental pollution, rather than methane capture. Indeed, ventilation is used to reduce the chance of methane build-up. This approach is not currently used at coal mines in NSW, and its application to active coal mines, and for methane capture, is uncertain.

3.7.2 Scope 1 emissions: diesel combustion

i Electrification

Here, ‘electrification’ means using electricity as the main energy source to power all mine operations, replacing fossil fuels such as diesel. FBICRC (2023) argued that, of all the potential solutions for improving the environmental performance of mining, electrification is the most promising.

Net-zero GHG emission targets have driven a strong interest in the electrification of mine vehicles and equipment, including the trialling and procurement of battery electric vehicles (BEVs), fuel cell electric vehicles (FCEVs) and diesel-electric hybrid vehicles (HVs). A survey of mining industry executives reported by Ratcliffe et al (2020) found the 89% of respondents expected mine sites to be electrified within the next 20 years. Vehicle and equipment manufacturers are researching and developing various electric technologies, and several specific examples were identified by FBICRC (2023).

Electrifying material extraction and movement, combined with using renewable power and on-site energy storage, can potentially result in a 100% reduction in scope 1 and scope 2 emissions, and a fully electrified mine can expect a 30% to 50% energy cost reduction (FBICRC 2023).

Some of the emerging electrification technologies are summarised below.

Electric underground trucks and loaders have been on the market for several years, with a slow but steady adoption⁴⁴.

It was noted by FBICRC (2023) that, for underground mines, electric vehicles will tend to have higher capital costs than the diesel equivalents, but the elimination of noxious emissions improves worker safety and reduces ventilation requirements, which can shorten mine development time. In addition, electric vehicles are likely to form a clearer pathway to future automation. The batteries for underground haul trucks typically have a capacity of less than 0.5 megawatt hours (MWh), making them easier to electrify than surface haul trucks.

For the large haul vehicles used in surface coal mining, there is also potential for on-board battery power to replace diesel power. From 2030, there should be viable options to replace the diesel engines and cooling systems of heavy mine vehicles with batteries. Such batteries will need to have a 1.5 to 1.6 MWh capacity.

Some important considerations (and uncertainties) with respect to BEVs have been identified by FBICRC (2023):

- **Cost.** Due to the low energy density of batteries, electric haul trucks need large battery packs. The added weight and volume of the battery pack results in higher costs and lower productivity from a reduction in material-carrying capacity. However, electric vehicles are likely to have reduced maintenance costs and improved reliability.
- **Charging infrastructure.** A well-designed charging infrastructure is necessary for efficient operation. Charging technologies include:
 - **Fast charging.** Fast-charging stations can provide high energy efficiency (>90%) and a high charging power (>150 kilowatt (kW)). However, the high charging power can adversely affect battery lifetime. The cost of a 350 kW charger is estimated to be between US\$ 128,000 and US\$ 150,000.
 - **Wireless charging.** Wireless charging technologies enable electric vehicles to be charged while moving (over an air gap of about 250 mm). This new technology can reach about 90% efficiency, and may have lower operational costs than fast charging and battery-swapping (see below). However, the harsh conditions at mines could greatly increase the cost of deployment. In addition, considering the size of the on-board batteries and drivetrain, the required charging power could be an order of magnitude higher than what commercial wireless chargers are currently capable of delivering.
- **Battery swapping.** Due to the limited storage capacity of batteries, they will need to be charged/swapped regularly. Battery swapping involves replacing a depleted battery with a fully charged one. This can significantly improve vehicle availability compared with conventional charging. However, battery swapping stations may have higher capital costs due to the need for a larger number of batteries and associated infrastructure, but lower battery replacement costs due to slower charging. Another disadvantage of battery swapping stations for coal mines is that they cannot easily be relocated.
- **The application to the mine vehicle fleet,** such as whether electrification requires new vehicles or could involve retrofitting of existing vehicles.
- **Safety.** The high charging power and large storage capacity of batteries will require protocols to ensure worker safety. Battery swapping may also introduce safety issues, such as the need to regularly handle large, heavy battery units. There is also a small but not insignificant risk of battery fires.

⁴⁴ <https://www.idtechex.com/en/research-report/electric-vehicles-in-mining-2024-2044-technologies-players-and-forecasts/994>

As with battery electric mine vehicles and equipment, manufacturers and mining companies are researching and developing various hydrogen fuel cell technologies. In 2022 Anglo American developed a large prototype haul truck powered by a combination of hydrogen fuel cells and batteries, producing a power of 2 MW. The truck was introduced at a mine site in South Africa. However, there are also barriers to the uptake of hydrogen, including a low energy density and the lack of a renewable hydrogen supply at a few remote mine sites.

An alternative to on-board power is tethering. This involves the connection of electrical equipment to a fixed power supply via a cable. According to FBICRC (2023), cable-tethering of electric vehicles in mining dates back 50 years. However, for hauling material over long distances at coal mines, the use of tethered equipment is unlikely to be a practical solution (Campey et al 2017).

Another technology for surface mines is 'trolley assist'. In trolley-assist systems, diesel-electric haul trucks are powered by electricity from a dedicated substation that is transmitted via a catenary system to the drive motors of the trucks. This allows for smaller batteries, and can lead to a substantial reduction in diesel consumption. Haul trucks use much more fuel travelling uphill than they do travelling downhill or on the flat, and therefore trolley assist systems offer most benefit on uphill slopes (e.g. pit and dump ramps). However, it is also beneficial on downhill slopes, as braking energy can be recovered. Additional benefits of trolley-assist include a faster travel speed, which improves productivity, and a longer truck lifetime. The disadvantages of trolley-assist systems include limited operational flexibility (due to fixed infrastructure), high capital cost, and safety issues (FBICRC 2023).

With reference to mining in Canada, Issa et al (2023) noted that trolley-assist technology has been available for decades. For example, during the energy crisis of the 1970s various mining companies explored trolley assist as a means to reduce their dependency on diesel. However, the mining industry lacked substantial incentives for widespread adoption. The Copper Mountain mine in southern British Columbia introduced a 1-kilometre electric trolley-assist system in 2022. This system powers 11 full-size hybrid trucks in hauling ore uphill from the main pit to the primary crusher of the operation.

In 2013, Atlas Copco introduced the 'Green Line' family of trucks in Australia. During normal operation, these were powered up and down ramps by an overhead, electrified trolley rail. Where there was no access to an overhead trolley rail, such as at loading and unloading stations, the truck disengaged itself from the trolley and automatically activated a small on-board diesel engine (Campey et al 2017).

The cost of erecting a trolley assist system varies from site to site. However, the total installation cost (including catenary overhead lines and pylons, substation, connection to the grid, transformer and rectifiers) is estimated to be 2 to 3 million euros⁴⁵ per kilometre (FBICRC 2023).

There would be some significant challenges associated with the use of trolley-assist systems at coal mines in NSW. Importantly, the operation at a coal mine typically evolves in a different way to that at a metal ore mine. In a metal ore mine the haul roads can remain in the same place, and just get deeper as mining progresses, whereas the spatial distribution of operations changes more frequently at a coal mine. This would mean that the trolley-assist infrastructure would regularly need to be relocated as a pit evolves.

According to Deloitte (2024), an indicative cost-effectiveness for mine vehicle electrification in NSW is \$256 per tonne CO₂-e abated. This is based on replacing diesel mining vehicles with battery electric ones. It includes haul trucks, and also loaders and excavators. The costs components included are vehicle cost, charging infrastructure for vehicles, and mine site electricity infrastructure upgrade.

⁴⁵ Around 3-5 million Australian dollars at the time of writing.

Box 10: Experience of electric haul trucks in Australia

Battery electric haul trucks have been in operation in Australian underground mines for several years. For surface mining in Australia, electric haul trucks are at the demonstration stage.

Rio Tinto and BHP are collaborating on a project that will test large battery electric haul truck technology at coal mines in Western Australia. Two Caterpillar trucks were tested in 2024, and two Komatsu trucks will be tested from 2026 (Rio Tinto 2024a).

Some of the main developments are currently taking place at iron ore mines. For example, Fortescue and Liebherr Mining have announced a partnership to jointly develop autonomous haulage at iron ore mines, including an intention to use fuel cell and battery electric technology (Fortescue 2024).

b Other mining equipment

Campey et al (2017) observed that mobile material handling equipment and crushing/grinding are emissions-intensive processes in coal mining, and emissions from these processes can be reduced through operational improvements and by implementing technologies that improve efficiency.

Electrified in-pit crushing and conveying (IPCC) has been identified as an alternative to conventional truck haulage and shovel operations. In IPCC operation, a mobile, semi-mobile or a stationary in-pit crusher is coupled with conveyors to remove the material from an open pit. The most efficient system of conveying is 'high angle conveying', which offers the shortest route on elevated conveyors, offering substantial savings in energy (Campey et al 2017). However, the regular changes in extraction at open-cut coal mines mean that IPCC is unlikely to be practical in many cases.

Vertical mills and high-pressure grinding rolls are other technologies currently under development that could greatly increase energy efficiency of crushing and grinding (Campey et al 2017).

Issa et al (2023) noted that tethered electric loaders have been used at a (non-coal) mine site in Canada.

Box 11: Experience of other electric mining equipment in Australia

In 2022 BHP introduced a battery-electric 'Jumbo' (used to drill holes in underground mines) at their polymetallic mine at Olympic Dam in South Australia. BHP has also been trialling this equipment at its Broadmeadow mine in Queensland (BHP 2024).

BHP has also employed a tethered electric excavator at its Yandi iron ore mine in Western Australia. The Liebherr electric excavator uses an electric motor with power fed to the machine by a trailing machine (Australian Mining 2024).

ii Automation

Automated mining involves the removal (or reduction) of human labour from the mining process. The automation of mine equipment has four main types: remote control (operation near equipment), teleoperation (operation at a distance), driver assist and full automation.

The automation of mine operations has the potential to improve precision, efficiency and productivity, to reduce energy consumption and costs, and to provide safer working conditions (although probably for fewer workers). Automated equipment can be used to perform work that is repetitive or in close proximity to hazards for humans. In some areas the mining industry is transitioning to automation where practicable.

To date, automation has been used in haul trucks, trains and drills. Automation can reduce the energy consumption of haul trucks through the optimisation of speed, acceleration and braking. Some authors have also explored the use of artificial intelligence to reduce energy consumption in haul trucks (e.g. Soofastaei et al 2016). Advances in artificial intelligence are likely to be enable optimal response to changing conditions.

Mine automation is expected to be closely aligned with electrification. The electrification of mine vehicles and machinery will also result in more real-time information about the equipment and how it is used. This provides an opportunity to optimise operation and reduce costs. For instance, information about the battery's state of charge, temperature and state of health could help design better charging, discharging and maintenance routines to avoid excessive battery degradation (FBICRC 2023).

Box 12: Experience of mine automation in Australia

Australia's mines are in the process of automating, and Australia already has the largest population of autonomous mine trucks (Mining Technology 2023). Significant advances have been made at iron ore mines in Western Australia. For example, Rio Tinto's Gudai-Darri iron ore mine in the Pilbara uses autonomous trucks, trains and drills, as well as the world's first autonomous water trucks and a robotic ore sampling laboratory (MCA 2022). Rio Tinto also sponsors the Centre for Mine Automation at the University of Sydney. BHP has deployed a number of autonomous mining components as part of its Next Generation Mining program, including autonomous drills and trucks in the Pilbara region.

So far, there has been some use of autonomous vehicles and equipment at underground coal mines, but little use at surface coal mines. Reasons for the limited uptake probably include a reluctance of coal mine operators to invest heavily in new technology, and the complex and changing nature of coal mine sites.

iii Renewable diesel

An emerging alternative to fossil diesel is renewable diesel. Renewable diesel can be produced through a variety of processes, but it is predominately produced through hydrotreatment, which involves adding hydrogen to a feedstock at high temperatures (DCCEEW 2023d). A wide variety of renewable feedstocks can be used in the production process. Unlike biodiesel, renewable diesel has similar chemical and physical properties to fossil diesel, and behaves similarly to fossil diesel when combusted in an engine. It can also be blended with fossil diesel at all ratios with minimal risk of engine operability issues. These factors potentially allow it to be used directly as a fuel in heavy vehicles and machinery, and some light vehicles, thus overcoming one of the disadvantages of biodiesel.

Renewable diesel is a recent technology, and the supply chain is still developing (TfNSW 2024). It is not currently produced commercially in Australia, and is in short supply globally. Conceivably, renewable diesel could become a transition fuel while other technologies – such as electrification and hydrogen – are being developed. Renewable diesel (and possibly biodiesel) may also present an option for mines that are unable to feasibly adopt electrification or other measures.

The NSW Government is currently developing a Renewable Fuels Strategy for NSW, which aims to diversify and expand the local renewable fuels industry⁴⁶.

⁴⁶ <https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/public-consultations/building-thriving-renewable-fuel>

iv Renewable methanol

Methanol is produced from biomass (bio-methanol) or from CO₂ and hydrogen produced from renewable electricity (renewable methanol or green methanol). Due to significantly lower carbon content and carbon neutral production, methanol use in diesel engines has been established in the marine industry. Dual-fuel systems are used to provide methanol in the intake and diesel directly into the cylinder, with the two fuels co-combusting. The outcome is reduced carbon emissions due to methanol burning. MAN Energy Solutions is currently offering methanol dual-fuel marine diesel engines as a retrofitting solution⁴⁷.

v Renewable hydrogen

An emerging retrofitting technology is a dual-fuel system which allows existing diesel engines to run primarily on hydrogen. Liebherr has converted a diesel wheel loader to hydrogen spark ignition engine power, operating with no carbon emissions⁴⁸. Similarly, KEYOU and Komatsu worked together to develop a mining dump truck with a 12-cylinder diesel engine retrofitted to a hydrogen spark ignition engine⁴⁹. Another retrofitting technology is currently being developed by the University of NSW⁵⁰, whereby hydrogen is injected directly into the combustion chamber. The hydrogen/air charge is then ignited by burning a small volume of diesel. The system has been proven to run using 90% hydrogen and 10% diesel, reducing CO₂ emissions by up to 77%. The hydrogen is produced from renewable feedstock.

3.7.3 Scope 1 emissions: other minor sources

i Petrol combustion

As noted in section 3.6.3, it seems likely that, where appropriate, petrol vehicles and equipment will be replaced over time with electric equivalents.

ii ANFO combustion

Few emerging alternatives to the use of ANFO for blasting are available in the literature. Campey et al (2017) noted that some novel blast designs using electronic initiation systems can increase mineral recovery, although these techniques may be less relevant to coal mining than other types of mining. Other options involving recycling and renewable (or low carbon) fuels in ANFO are considered to be more relevant to scope 3 emissions (see section 3.7.5).

iii Oils and greases

There are emerging technologies that could potentially reduce the environmental impacts of lubricants. For example, some companies are exploring the use of nanotechnology to create lubricants that can repair small cracks and scratches in equipment, helping to extend the life of equipment and reduce waste.

⁴⁷ <https://www.man-es.com/discover/methanol-dual-fuel-retrofit>

⁴⁸ <https://www.liebherr.com/en-au/n/pioneering-work-in-the-quarry-liebherr-and-strabag-test-hydrogen-wheel-loader-100608-4862672>

⁴⁹ <https://www.keyou.de/news-and-blog/keyou-develops-hydrogen-powered-dump-truck-for-global-construction-equipment-leader-komatsu>

⁵⁰ <https://www.unsw.edu.au/engineering/research-technology/is/converting-diesel-engines-to-run-on-hydrogen>

iv Fugitive SF₆

As mentioned earlier, alternatives to SF₆ for high-voltage equipment are at the early stages of entering the market. USEPA (2020) noted that various technologies are under development, but focussed on the two most promising options:

- Vacuum circuit breakers (VCBs). These use vacuum interrupters for switching and dry air (a mixture of nitrogen and oxygen) for the insulation medium. VCBs can be direct replacements for SF₆-based circuit breakers. For low/medium-voltage applications, VCBs are widely available. The technology for high voltage applications is under development, but scaling to extra-high voltage applications is difficult. VCB units are a more expensive technology, but the total lifetime cost of ownership is expected to be lower.
- Fluorinated gas circuit-breakers. Some gas mixtures for circuit breakers use small amounts of fluoroketone or fluoronitrile gas, which have lower GWPs than SF₆, in conjunction with CO₂ and oxygen. These systems can be used at high voltages, and scaling the technology up to 550 kV is possible in some cases. Fluorinated circuit breakers are also direct replacements for SF₆-based systems, and have similar operational requirements. The lifetime cost of ownership is expected to be similar to that of SF₆-based circuit breakers.

v Coal oxidation

No emerging measures for addressing oxidation in coal stockpiles were identified in this review.

vi Vegetation removal

An emerging strategy to reduce GHG emissions from vegetation removal is the use of pyrolysis. Pyrolysis is the thermal degradation of vegetation using low-oxygen technology to produce biochar. Through this mechanism, the carbon in the vegetation is converted into a form that is relatively resistant to decomposition, thus resulting in sequestration. The stabilisation of the carbon as biochar reduces the amount of CO₂ and methane released to the atmosphere compared with decomposition (Simmons et al 2021). The resulting biochar can be used in a variety of ways, including soil management and remediation, manufacturing of products such as bio-oil and syngas⁵¹, farming and energy production.

The use of pyrolysis to manage GHG emissions from vegetation is not currently a widespread practice at NSW coal mines, but it could complement current practices involving reforestation and rehabilitation, or as a renewable energy source. There have been several Australian projects which have investigated or developed biochar systems for use predominantly in the agriculture industry, but also in the coal mining industry (e.g. Earth Systems remote pyrolysis projects⁵²).

3.7.4 Scope 2 emissions

i On-site renewable energy generation

An emerging approach to reducing scope 2 emissions is to incorporate large-scale renewable energy sources into mine sites (Liu et al 2021). Examples include wind power, solar power and geothermal power, potentially in combination with energy storage systems. Electricity generated by these systems can be utilised before electricity is drawn from the grid (known as 'behind the meter').

For Canadian mining operations, Issa et al (2023) identified various renewable energy technologies. A number of Canadian mines have explored the integration of wind power into operations, incorporating energy storage methods such as fuel cells, lithium-ion batteries, compressed air and flywheels.

⁵¹ Syngas – also known as synthesis gas – is a mixture of hydrogen and carbon monoxide in various ratios.

⁵² <https://earthsystems.com.au/services/energy-and-carbon/biochar-production/>

Case studies included wind turbines with a capacity of 2 MW to 10 MW. The authors noted that photovoltaic (PV) solar panels have found promising applications in electrifying isolated Canadian mine sites, and cited examples of installations at mines with power ranging from 27 kW to 2 MW, with proposed installations up to 5 MW.

Box 13: Experience of on-site electricity generation in Australia

An increasing number of remote Australian mines (outside NSW) are being powered with renewable electricity generated on-site.

Solar farms have been installed by operators such as BHP and Rio Tinto. For example, Rio Tinto's Gudai-Darri iron ore mine in the Pilbara features a 34 MW solar farm (MCA 2022)

Wind power at mines has been used overseas (e.g. at Rio Tinto's Diavik diamond mine in Canada), and has been installed at other types of mine in Australia. For example, EDL operates the Agnew Hybrid Renewable Microgrid which services the Agnew Gold Mine in Western Australia (Figure 3.8). The project started in 2020 and was the first in Australia to utilise wind power on a large scale to support mining operations (EDL 2024). However, wind power is not common at coal mines in Australia (MPI 2024).



Source: Photograph by CS Foto

Figure 3.8 Wind turbines, solar farm and batteries at EDL's Agnew Hybrid Renewable Microgrid site

ii On-site energy storage

On-site energy storage will not, in itself reduce GHG emissions, but would probably be important in facilitating the wider electrification of mining operations, particularly where energy is stored from on-site renewable sources. Although various energy storage methods are being investigated, it is likely that battery storage will be the most common approach. Battery storage technology is advancing, but it still needs to overcome the challenges of size and robustness needed for mine sites.

Box 14: Experience of battery storage at mines in Australia

The use of batteries to store energy for electricity generation at Australian coal mines is not yet widespread, but has been employed at other mining operations in recent years.

In 2023 Rio Tinto approved a new 12.4 MW solar farm and 2.1 MWh of battery storage, providing renewable energy for the Amrun bauxite mine in Weipa, Queensland. The initiative is expected to reduce Amrun's diesel consumption for electricity generation by 37%, and annual GHG emissions by 14,000 tonnes of CO₂-e. The system will add to the existing 5.6 MW of solar power and 4 MWh of battery storage at Weipa (Rio Tinto 2024b).

Neoen's Goyder wind farm is set to provide electricity to BHP's Olympic Dam copper mine in South Australia, and will be supported by the nearby Neoen Blyth Battery (Commonwealth of Australia 2024)

3.7.5 Scope 3 emissions

The topic of future developments to reduce scope 3 emissions is very large, and is beyond the scope of this review. Various measures are being developed to reduce emissions from upstream and downstream processes (e.g. the manufacture of mining equipment, or recycling).

By way of example, several approaches are under development to reduce scope 3 emissions from the explosives used in blasting. For example, Orica has added new 'tertiary catalyst' technology to its nitric acid plant that can reduce emissions of N₂O. Waste oils or renewable alternatives to fuel oil can potentially also be used in ANFO (Resende et al 2014; Ali et al 2021). Potential approaches to reducing GHG emissions from the ammonium nitrate component of ANFO is being considered include nitrate-free explosives, and switching ammonia production to green using hydrogen obtained through renewable electricity.

3.8 Drainage gas utilisation

3.8.1 Overview

This section reviews the on-site capture of methane in drainage gas from coal mines, and its potential beneficial uses. Methane capture and utilisation can add significant value to a mining operation, such as revenue from gas sales, reduced heating/cooling costs and on-site electricity generation. The uses for methane described here are technically feasible, even though in some cases they may be impractical or uneconomical.

The following assumptions are made:

- Methane utilisation excludes the venting of mine gas, as well as flaring and oxidation.
- The utilisation of methane for electricity generation at (or near) a mine site is considered to be an 'existing' use. All other uses of methane are considered to be 'emerging'.

As noted earlier, for most uses the overall effect with respect to GHG emissions is the oxidation of methane to CO₂, which reduces the GWP of the mine gas compared with direct release, but does not eliminate emissions. It can also delay the impact if the methane can be stored for a significant amount of time, although practical considerations and commercial pressures on gas use would tend to work against long-term storage.

In terms of gas capture, for active underground mines methane can be captured using the drainage methods described earlier. The gas from active surface mines is not normally captured. The methods for extracting gas from closed underground mines differ from those employed to capture gas from active underground mines. Once a mine (or mine area) is sealed from the atmosphere, gas from all underground sources becomes potentially available for extraction. Access to closed mines for gas extraction is achieved through former shafts or gas

extraction boreholes. Initially, there may be sufficient reservoir pressure to produce methane at the surface. Eventually, suction will be necessary to draw gas from the mine void (UNECE 2019).

Where methane can be recovered from a closed and well-sealed gassy mine, the concentration typically ranges from 15% to 90%, and the mine atmosphere contains little or no oxygen. The other major gaseous components are nitrogen and CO₂, sometimes with low concentrations of carbon monoxide and traces of non-methane hydrocarbons. The main factor affecting gas quality is dilution with air that is drawn into the mine from inadequately sealed surface entries. Any air drawn into a closed mine could conceivably cause spontaneous combustion. Air leakages will reduce the methane concentration, and will also limit the achievable suction and flow. Leakage and ingress must therefore be minimised to ensure stable gas quality and quantity (UNECE 2019).

Various options are available for utilising the methane captured from active and closed underground mines. In most cases, emissions are effectively converted from scope 1 to scope 3 during utilisation, and in theory the utilisation of gas could lead to near-zero scope 1 methane emissions from coal mining. The remaining scope 1 fugitive methane emissions would be those from coal in the post-mining stages, such as coal handling and processing (UNECE 2021).

The uses for mine gas are similar to those that are available for natural gas. Some potential uses of methane from coal mines are summarised in Table 3.8 and the following sections. Each option has specific constraints, advantages and disadvantages. The commonest options internationally for methane use are sale to natural gas pipelines and power generation, including combined heat and power (CHP).

Table 3.8 **Utilisation of methane captured from coal mines**

Typical gas quality and methane concentration		Type of use	Applications	Advantages	Disadvantages
Purified, high quality gas	95% to 97%	Pipeline gas	Injection into natural gas pipelines.	- Natural gas equivalent. - Profitable where gas prices are high, and pipeline infrastructure exists.	- Gas purity standards are high, and purification (if needed) is costly, so only feasible for high-quality, pre-drained gas or treated gas. - Requires access to established pipeline infrastructure.
		Chemical feedstock	High-quality gas for the manufacture of chemicals (e.g. fertilisers, methanol, formaldehyde).	- Alternative use for high quality gas. - Potential for sequestration.	Generally requires purification, with high processing cost.
		Vehicle fuel	Production of CNG and LNG fuels for road vehicles.	Potentially cheaper than diesel.	- Processing, storage, handling and transport costs. - Purification standards are high.
		Hydrogen production	Steam methane reforming (SMR) or pyrolysis.	- Proven technology. - Low CO₂ emissions for pyrolysis.	High CO₂ emissions and cost for SMR.
Medium quality gas	>35%	Power generation (and waste heat use – CHP)	Gas-engine generators producing power for mine use or export to the grid, with heat recovery if required.	- Proven technology. - Can generate according to demand, within limits. - Waste heat recovery for heating mine buildings, accommodation and shafts.	- High capital cost. - Only feasible where electricity price is high. - Variable output, and so may not be suitable for electricity grid. - Long-term gas flow uncertainty, with declining gas resource over time. - Grid connection can be costly. - Regular maintenance requires commitment of mine operator. - Potential for emission reductions to be eroded (e.g. relative to flaring) if an additional input of natural gas is required.
		Town gas or industrial gas	Local residential heating, and commercial or industrial use such as firing kilns and boilers.	- Low-cost fuel source. - Minimal gas treatment required. - Can potentially be supplied on demand.	- Cost of pipeline distribution system and maintenance. - Variable gas quality. - Long-term supply can be problematic. - Costly gas holders needed to manage peak demand.
Medium quality gas	>30%	Mine site	Heating, cooking, boilers, coal drying, residences.	- Displaces any coal use. - Clean, low-cost energy source.	May be less economically beneficial to use on-site than off-site.

Typical gas quality and methane concentration		Type of use	Applications	Advantages	Disadvantages
Low quality gas	>25%	Spiking gas	Injecting variable and low quality gas into natural gas pipelines.	• Uses low quality gas that would otherwise be vented.	• Only low volumes can be added to ensure the natural gas remains within specification limits. • Price is low and may be marginal commercially. • Potentially explosive mixtures must be avoided prior to injection.

Sources: Karacan et al (2011); UNECE (2016); UNECE (2019)

The suitability of mine gas for a particular use is primarily dependent on its quality, such as the methane concentration and the stability of supply. For example, drainage gas can be fed into a natural gas grid, provided the system is managed to maintain gas quality in accordance with best practice (UNECE 2021). However, various other factors need to be considered, including energy prices, gas and electricity transmission arrangements, regulation, infrastructure and access, planning, environmental issues, corporate objectives and customer requirements (UNECE 2016, 2019). It is possible that not all captured gas can be used commercially. Mining conditions also often change frequently. Gas supply parameters (e.g. produced amount or purity) can change, which might result in failure or planned shutdown of the corresponding equipment.

Drainage gas is a time-limited resource, in that it is available during the period leading up to the start of coal extraction (UNECE 2024). This means that gas drainage needs to take place well before the start of mining.

3.8.2 Pipeline gas

A potential use for drainage gas from a coal mine is injection into an existing gas pipeline (Liu et al 2021; UNECE 2021). Drainage gas can, in principle, be injected into existing pipelines with limited additional processing. However, pipeline operators often have strict gas quality specifications (e.g. concentrations and flow rates) that must be met before gas can be injected. Pipeline standards typically specify a methane concentration of around 95% (UNECE 2019). The captured methane from a coal mine can therefore be sold to the gas market provided the treatment, compression and transport infrastructure is available at the mine. The economic attractiveness of gas injection into pipelines depends on competition from alternative gas supplies.

Box 15: Experience of pipeline export in Australia

In Australia, no examples of the export of high-quality drainage gas from coal mines to pipelines were identified in the literature.

3.8.3 Chemical feedstock

Methane is an important feedstock in the chemical industry, and there are numerous international examples of coal mine gas being used for industrial purposes. For example, methane can potentially be used in the manufacture of carbon black, formaldehyde, methanol, synthetic fuels, dimethyl ether (DME) and fertiliser (Karacan et al 2011; UNECE 2016). An important benefit of using methane as a feedstock is that it can effectively be sequestered in products, rather than being released to the atmosphere as a GHG.

3.8.4 Vehicle fuel

Methane is the main component of two fuels that can be used in road transport: compressed natural gas (CNG) and liquified natural gas (LNG). According to KPMG (2021), the production of CNG can be considered for small or remote mines, where an investment in pipeline infrastructure cannot be justified. The production of CNG typically requires pre-treatment equipment, a compressor and trucks for gas transport.

3.8.5 Hydrogen production

One use of methane that is not commonly referred to in the literature with respect to coal mines is hydrogen production. Steam methane reforming (SMR) is currently one of the most widely used methods for producing hydrogen. The process generally involves two steps (Agyekum et al 2022; Kindra et al 2023):

- Step 1: The reforming process, in which methane and steam are mixed over a catalyst bed at moderate-high pressure (1.5-3 megapascals (MPa)) and high temperature (700-1,100°C). This forms syngas (a combination of CO and hydrogen).

- Step 2: A shift reaction, where there is the reaction of additional steam with the CO from the initial phase to produce additional hydrogen and CO₂.

SMR is an established technology and has a high efficiency. However, it requires a large, complex reactor and a high temperature, and can have fluctuating hydrogen yields because of feedstock impurities. Although converting methane into hydrogen via SMR can reduce GHG emissions, as with other uses the process itself produces CO₂. For SMR, high quality methane feedstock (>90%) is needed to maximise the reaction efficiency and catalyst performance.

Another established method of producing hydrogen from methane, and one that uses relatively simple technology, is methane pyrolysis. In pyrolysis, methane is converted through thermal decomposition into gaseous hydrogen and solid carbon, without creating any direct CO₂ emissions. Several techniques are used, including direct and indirect pyrolysis. The direct method involves heating methane in the presence of a catalyst, which ensures a high concentration of hydrogen but can also cause carbon formation on the catalyst surface. The indirect method involves decomposing hydrocarbons into hydrogen and carbon. It is more stable and more efficient, but requires additional processing (Kindra et al 2023; IEA 2023b).

Although producing hydrogen from coal mine methane is technically feasible, its viability at any given location depends on, amongst other things, the amount of methane produced, investment costs and market factors.

3.8.6 Power generation/CHP

Drainage gas from coal mines can be used as a fuel for power generation where the methane concentration is above around 35% and is relatively stable. Electricity can be generated either on-site or exported to the grid, and power generation may be combined with heat recovery.

Power generation projects using coal mine methane are operating in several countries, including China, Australia, the United Kingdom and Germany. Some coal mines in NSW do already use methane for electricity generation, although this is not a widespread practice, and few (if any) mines capture and use methane for other reasons.

Power generation using coal mine gas is generally achieved with reciprocating engines, although gas turbines can be used in some applications. These are smaller, lighter and more efficient than reciprocating engines, and historically have had lower operation and maintenance costs. However, gas turbines cannot typically utilise mine gas below 50% methane, and require the gas to be compressed prior to use (Karacan et al 2011; UNECE 2019).

In the case of VAM, the very low methane concentration means that it is not useful for power generation. A supplementary fuel – such as drainage gas – has to be blended with VAM to increase the methane concentration (USEPA 2019a). Power generation using VAM directly is therefore generally not commercially viable. However, it is possible that – where VAM is treated using RTO – the resulting heat could be used to power a steam turbine to generate electricity.

Where methane is utilised for electricity generation, there is potential for some of the emission-reduction benefit to be eroded relative to that for, say, flaring. For example, where the methane is used for electricity generation, an additional input of natural gas (with associated emissions) may be required to ensure a consistent supply of fuel. However, any avoided emissions for electricity generation using mine gas should also be considered.

An indicative cost-effectiveness for electricity generation using drainage gas is \$-17 to \$-4 per tonne CO₂-e (CSIRO 2024; Deloitte 2024). Presumably the values are negative due to the inclusion of revenue from electricity sales. The value of \$-17 per tonne CO₂-e is from CSIRO and is for Australia. It assumes electricity generation using 25% of current drainage gas from underground mines. The value of \$-4 per tonne CO₂-e is from Deloitte and is for underground mines in NSW, and it was assumed that these mines already had gas drainage systems in place.

Box 16: Experience of power generation from methane in Australia

Drainage gas from coal mines has been used to generate electricity for several decades. For example, the Appin and Tower power station, near Appin in NSW, began operation in 1996, and has a capacity of 85 MW. This power station now forms part of EDL's portfolio of power stations in Australia that use methane from coal mines as the primary fuel, which also includes the Queensland sites at German Creek (opened 2006, 38 MW), Moranbah North (opened 2008, 67 MW), Grosvenor 1 and 2 (opened 2016, 36 MW), and Oaky Creek 1 and 2 (opened 2006, 36 MW). A 10 MW power station also opened at the Glennies Creek Mine in the Hunter Valley 2007, and is now operated by Clarke Energy. Figure 3.9 shows an example of the use of drainage gas to generate electricity, in this case at the Grosvenor Power Station at Moranbah in Central Queensland.

The West Cliff VAM Project, located at BHP Billiton Illawarra Coal's West Cliff Mine near Wollongong in NSW, was the world's first commercial scale VAM-to-power project. The project operated from 2007 to 2017 (West Cliff mine closed in 2016). The project used RTO to treat VAM with 0.9% methane, generating heat to produce 6 MW of electricity from a conventional steam turbine. However, supplementary drainage gas was required to sustain the operation of the RTO.



Source: Photograph by CS Foto

Figure 3.9 Example of power generation from coal mine methane at EDL's Moranbah North site

3.8.7 Town gas

'Town gas' refers to the medium-quality gaseous fuel that is supplied to domestic users for heating and cooking. The gas used for this purpose would typically have a methane content of 30% to 40%.

3.8.8 Spiking gas

Where the methane quality is unsatisfactory for direct use, one way to improve it is to redesign wells and boreholes for efficient gas recovery by mixing low-quality gas with high-quality gas, or by ‘spiking’ the mine gas with hydrocarbons with a higher molecular weight (Liu et al 2021).

3.8.9 Mine site use

Potential on-site uses of methane at coal mines include heating, cooking, boilers and coal fines drying (UNECE 2016).

3.9 Analysis of mitigation measures

An analysis of the existing and emerging GHG mitigation measures was conducted. The analysis had two components:

- A review of the mitigation measures that have been included in GHG assessment for a selection of coal mine projects.
- A qualitative analysis of the mitigation measures identified in the literature review.

3.9.1 Mitigation measures in project assessments

i Assessment approach

A review was conducted of the mitigation measures that have been proposed in the GHG assessment reports and management plans for a selection of coal mine projects. These measures covered scope 1 and scope 2 emissions. There have been many GHG assessments for new mines and modifications to existing mines over the last few decades. For simplicity, this review was restricted to a limited number of examples of coal mines in NSW, the aim being to show a broadly representative sample that illustrated how plans have evolved over time. The review was not designed to be comprehensive.

The assessment involved the following steps:

- GHG assessment reports and measurement plans since around 2012 were taken from public, on-line sources.
- Historically, the amount of detail provided in these documents has been limited, and any report with only minimal detail was excluded from the assessment. It was considered that more recent documents, describing a wider range of measures would be more representative of future assessments and plans.
- In total, nine mine projects were included in the assessment. Four of these were open-cut mines, and five were underground mines.

ii Measures for scope 1 emissions

The proposed measures for scope 1 emissions are identified in Table 3.9.

The five underground mines included in the assessment all proposed gas drainage and flaring, with two mines also considering the use of RTO. No management of GHG emissions from stockpiles was proposed. Each mine also proposed or considered either on-site or off-site power generation using methane. Fewer measures were proposed to address GHG emissions from diesel combustion at underground mines compared with open-cut mines. At the Tahmoor South mine, much of the equipment used to mine coal is powered by electricity, including the coal haulage systems.

Table 3.9 Measures included for Scope 1 emissions in NSW coal mine GHG assessments

	Measures implemented or proposed ^(a)								
	Open-cut mines					Underground mines			
	Bulga optimisation	Wambo	Glendell	Ravensworth	Integra	Tahmoor South	Maxwell	Appin	Tahmoor South MOD 3
Fugitive CH₄ treatment									
Gas drainage	x	x	x	x	✓	✓	✓	✓	✓
Flaring	x	x	x	x	✓	✓	✓	✓	✓
RTO	x	x	x	x	x	x	x	§	§
Methane capture and use									
Power generation (on-site)	x	x	x	x	✓	§	§	x	✓
Power generation (off-site)	x	x	x	x	✓	x	x	✓	x
Diesel combustion									
General mine planning	✓	✓	✓	✓	x	✓	§	§	✓
Optimising haul routes	✓	✓	✓	✓	-	✓	x	x	✓
Payload management	✓	✓	✓	✓	x	x	x	x	x
Reducing idling	✓	✓	x	x	x	x	x	x	✓
Fleet planning	✓	✓	✓	✓	x	x	x	x	x
Energy-efficient vehicles/equipment	✓	✓	✓	§	✓	x	§	✓	x
Alternative fuels	x	x	§	§	x	x	x	x	x
Electrification									
Conveyors	x	x	x	x	x	x	✓	✓	x
Other	x	x	x	§	x	✓	x	x	✓
ANFO combustion									
Blasting strategy	✓	✓	✓	x	x	x	x	x	x
Post-closure									
Flooding	-	-	-	-	x	x	x	x	x
Sealing	-	-	-	-	x	✓	x	x	✓
Reference	Umwelt (2012)	Umwelt (2016)	Umwelt (2019)	Glencore (2022b)	Jacobs (2017)	ERM (2018)	TAS (2019)	EMM (2021)	EMM (2024)

Note

(a) '-' = generally not relevant; ✓ = included; x = not included; § = identified for consideration or undergoing trial

For the four open-cut mines, no measures were proposed to address fugitive methane emissions (evidence from the industry scan – see chapter 4 – suggested that gas drainage is being considered at some mines). For diesel combustion, however, all open-cut mines proposed a number of measures, and in particular conventional approaches such as mine planning to reduce material handling, optimising haul routes and payload management. Some mines were planning to implement, or were considering, more efficient mine vehicles and equipment. Some mines were also considering the use of alternative fuels. No open-cut mines were proposing a major electrification of equipment.

No mines proposed measures to reduce emissions from minor sources such as petrol combustion, SF₆, oils/greases or coal oxidation.

iii Measures for scope 2 emissions

The proposed measures for scope 2 emissions are identified in Table 3.10. At both open-cut and underground mines, these concentrated mainly on general improvements in energy efficiency with, in some cases, reference to specific appliances. One mine (Tahmoor South) proposed the use of on-site renewable energy.

Table 3.10 Measures included for Scope 2 emissions in NSW coal mine GHG assessments

	Measures implemented or proposed ^(a)								
	Open-cut mines					Underground mines			
	Bulga (optimisation)	Wambo	Integra	Glendell	Ravensworth	Tahmoor South	Maxwell	Appin	Tahmoor South (MOD 3)
General energy efficiency	✓	✓	✓	✓	✓	✓	✓	✓	✓
Energy-efficient lighting	✗	✓	✓	§	✓	§	✗	✗	✓
Energy-efficient HVAC	✗	✓	✗	✗	✓	✗	✗	✗	✗
Renewable grid electricity	✗	✗	✗	✗	✗	✗	✓	✗	§
On-site renewable energy	✗	✗	✗	✗	✗	✗	✗	✗	✓
Reference	Umwelt (2012)	Umwelt (2016)	Jacobs (2017)	Umwelt (2019)	Glencore (2022b)	ERM (2018)	TAS (2019)	EMM (2021)	EMM (2024)

Note

(a) ‘-’ = generally not relevant; ✓ = included; ✗ = not included; § = identified for consideration or undergoing trial

3.9.2 Qualitative analysis of mitigation measures

i Method

In the qualitative analysis, consideration was given to the following aspects for each type of measure:

- Place in the mitigation hierarchy.
 - The *NSW Guide for Large Emitters* presents a hierarchy of mitigation that proponents should follow. The order of priority for management practices is as follows:

- Avoid. Avoiding the production of GHGs represents the highest level of control. It may be achieved through planning, appropriate technology and site selection.
- Reduce. If avoidance cannot be reasonably achieved, GHG emissions can be reduced through using more energy efficient processes, upgrading equipment or introducing controls.
- Substitute. Where possible, remaining GHG emission processes can be switched to lower-emissions ones. For example, high-carbon energy sources can be replaced with renewable energy sources, or fuels with a lower carbon content can be used.
- Offsetting residual emissions. This is seen as a 'last resort' after all reasonable avoidance, reduction and substitution measures have been taken.
- In the analysis each measure was categorised according to the first three approaches. The offsetting of GHG emissions was excluded from the study, noting that some general principles for offsetting are available elsewhere (e.g. Climate Active 2022).
- Readiness for implementation and the time horizon for development.
 - In addition to being broadly identified as 'existing or 'emerging', mitigation measures have been categorised according to three broad categories of readiness with respect to implementation at coal mines (adapted from CCA (2024)):
 - R&D. Technologies that are still in the research and development stage, or cannot yet be deployed due to significant barriers that will take some time to overcome.
 - Demonstration. Measures that are available but not yet widely adopted. Barriers need to be overcome for the associated technologies to become widely available and deployed to their full potential.
 - Mature. Measures that are ready and available to be deployed now. Mature technologies are already being widely adopted, but barriers may still prevent their full, rapid deployment in some circumstances.
 - An area for future analysis could be a more detailed breakdown of the technology commercial pathway for emerging measures.
- Barriers to uptake.
 - The barriers to the uptake of measures were considered where they were identified in literature or by stakeholders. These included, for example, a lack of technology providers, safety concerns, a lack of supporting infrastructure, capital expenditure (CAPEX) and operating expenditure (OPEX), and the complex layout and terrain of coal mines. In addition, mining companies may not have the necessary expertise to design, build and maintain the technology (IEA 2023a). A detailed assessment of barriers was outside the scope of the study (e.g. financial or safety analysis).
- Risks or disadvantages.
 - There may be risks or disadvantages associated with implementing a particular measure.
- Co-benefits.

- Some measures can have significant co-benefits, such as improvements in safety, and reductions in air pollution and noise from mining operations.

The cost implications of mitigation were not quantified in the analysis, as these are very location-specific, with many factors to consider (e.g. the gas content of the coal seam and hence the overall scale of treatment required, ancillary infrastructure). This could be an area for future analysis. For a given site the particular conditions need to be carefully considered to determine the actual costs (UNECE 2024). Another area for future analysis could be the ability of coal mining companies to access finance to cover the costs of mitigation measures.

ii Results

The qualitative analysis considered GHG mitigation measures in the following groups:

- | | | | |
|---------------------|---------------------|---------------------|--------------|
| • Existing measures | – Scope 1 emissions | ▪ Fugitive methane | (Table 3.11) |
| | | ▪ Diesel combustion | (Table 3.12) |
| | | ▪ Other processes | (Table 3.13) |
| | – Scope 2 emissions | | (Table 3.14) |
| • Emerging measures | – Scope 1 emissions | ▪ Fugitive methane | (Table 3.15) |
| | | ▪ Diesel combustion | (Table 3.16) |
| | | ▪ Other processes | (Table 3.17) |
| | – Scope 2 emissions | | (Table 3.18) |

For fugitive methane emissions from active underground mines, the measures that are technically feasible at present are RTO and flaring. The barriers to implementation are mainly related to safety, cost and methane concentration. For safety, implementation could be tightly controlled through regulation. For cost, a cost-benefit analysis of mitigation options on a mine-by-mine basis would be appropriate, given the various factors that need to be considered. Other major considerations include the characteristics of the mine gas, integration with the existing facility, and the availability of appropriate skills and expertise. Pre-drainage of mines is important, as it offers the potential for the resulting gas to be used productively, rather than being flared.

For active surface mines, mitigation is not developed.

For closed underground mines, existing measures for fugitive methane include mine sealing and flooding. Mines going through the decommissioning and closure process in NSW have regulatory obligations that include sealing. There can still be gas leakage with these in place, although the emission rate will tend to decrease with time. Flaring is a potential option for treating methane at decommissioned mines, although it is not widely practiced.

The existing measures for diesel combustion generally focus on improving the efficiency of mine operations. They are mostly well-established, and should already be implemented (or in the process of being implemented) at coal mines in NSW. Similarly, the existing measures for other minor GHG sources are well-established, with few significant barriers to implementation.

The existing measures for scope 2 emissions can also be readily implemented in principle. As the NSW grid decarbonises, scope 2 emissions should decrease substantially, even though the demand for electricity at mine sites will probably increase.

The emerging measures for fugitive methane at active underground mines will essentially have the same overall effect on GHG emissions as the existing methods (i.e. conversion to CO₂). However, for both underground mines and surface mines, it is anticipated that beyond 2030 there will be more emphasis on the capture of methane for productive use, primarily through gas drainage.

The emerging measures for diesel combustion concentrate strongly on mine electrification. Although a range of technologies are being developed, it seems likely that the use of on-board batteries will be the preferred option for haul trucks and other heavy mining equipment, in combination with a supply of renewable energy (possibly on-site) for charging. Automation will also probably increase in line with electrification.

There are few emerging measures for other minor processes at coal mines, and the measures that have been identified in this review will probably not bring significant additional benefits.

The emerging measures for scope 2 emissions focus on renewable on-site energy, in combination with energy storage (probably using batteries). Several ore mines in Australia have begun to implement these measures.

Table 3.11 Existing measures for scope 1 emissions – fugitive methane

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness	Potential barriers	Risks or disadvantages	Co-benefits
Active underground mines							
VAM	Thermal oxidation	Destruction of VAM through RTO	Reduce (reduces GWP through conversion of CH ₄ to CO ₂)	Mature	• High CAPEX • Safety regulation and approvals process • Difficult to integrate in existing facility • Lack of technical expertise at mines	• Air pollution and noise • Safety • Residual CO₂ emissions	• Dust reduction
Drainage gas	Flaring	Capture of gas through boreholes, followed by combustion in a flare	Reduce (reduces GWP through conversion of CH ₄ to CO ₂)	Mature	• Longer lead times ahead of mining (for drainage) • High CAPEX for multiple flaring units • Variable quality of drainage gas	• Air pollution and noise • Safety • Residual CO₂ emissions	• Potential for CH₄ capture and use (when not flared)
	Capture and use for electricity generation	Capture of gas through boreholes, followed by collection and use at or near a mine for electricity generation	Reduce (reduces GWP through conversion of CH ₄ to CO ₂)	Mature	• Longer lead times ahead of mining (for drainage) • High CAPEX • Variable quality and quantity of drainage gas	• Residual CO₂ emissions	• Uses CH₄ productively • Reduced purchased electricity
Active surface mines							
Drainage gas	None identified	-	-	-	-	-	-
Closed underground mines							
Fugitive CH ₄	Mine flooding	Natural mine flooding, combined with drainage and capture of gas	Reduce (reduces source strength)	Mature	• Unfavourable geological or climatic conditions	• Contamination of aquifers and soils • Can take years for a mine to flood, with CH₄ potentially escaping • Structural integrity	-
	Mine sealing	Sealing of mines where flooding is not feasible	Reduce (reduces source strength)	Mature	• CH₄ sources can be difficult to locate	• CH₄ leaks through poorly sealed shafts, cracks and fissures	-

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness	Potential barriers	Risks or disadvantages	Co-benefits
Post-mining activities							
Coal stockpiles	Various measures	Measures include sealing, dust suppressants, biological stabilisation	Reduce	Mature	- Lack of financial incentive - No regulatory driver	Only a temporary measure unless gas collection is in place	Potential for CH₄ capture and use

Sources: CCA (2024); IEA (2023a)

Table 3.12 Existing measures for scope 1 emissions – diesel combustion

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness	Potential barriers	Risks or disadvantages	Co-benefits
All heavy mining vehicles and equipment	Mine planning	Planning and scheduling mine operations to minimise material handling, optimise payloads, reduce haul route lengths, reduce gradients and avoid unnecessary stops	Reduce (improved efficiency of processes)	Mature	-	-	Reduced noise and air pollution
	Fleet planning	Structuring of haul truck fleet (e.g. truck capacity) to minimise energy consumption	Reduce	Mature	-	-	
	Energy efficient units	Procurement of energy-efficient vehicles and equipment, including ventilation, lighting and control systems	Reduce	Mature	-	-	
	Servicing and maintenance	Maintenance of vehicles and equipment according to manufacturers' specifications	Reduce	Mature	-	-	

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness	Potential barriers	Risks or disadvantages	Co-benefits
	Renewable fuels	Switching to biodiesel (likely to be an interim measure)	Substitute	Mature	• High OPEX • Lack of supply • Vehicle modifications • Long-term storage • Increased maintenance	-	-
Light vehicles	Electrification	Hybrid, BEV	Reduce	Mature	• High CAPEX • Range • Power limitations	-	• Reduced noise and air pollution
Haul trucks	Driver training	Eco-driving	Reduce	Mature	-	-	• Reduced noise and air pollution

Sources: CCA (2024); Advisian (2022)

Table 3.13 Existing measures for scope 1 emissions – other processes

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness	Potential barriers	Risks or disadvantages	Co-benefits
Petrol combustion	Electrification	Hybrid, BEV	Reduce	Mature	-	-	• Reduced noise and air pollution • Reduced oil/grease use
	Driver training	Eco-driving	Reduce	Mature	-	-	• Reduced noise and air pollution
ANFO combustion	Optimised blasting strategy	Optimisation of blasting to minimise the movement of equipment and rehandling of material	- (ANFO use is not reduced)	Mature	-	-	-
Oils, greases	Recycling	Recycling of oils and greases	Reduce	Mature	-	-	-
Fugitive SF ₆	Best practice management	Operational protocols, gas accounting, training, recycling, LDAR, equipment upgrades	Reduce	Mature	-	-	-

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness	Potential barriers	Risks or disadvantages	Co-benefits
Coal oxidation (stockpiles)	Various measures	Covering and sealing stockpiles, dust suppressants, biochemical agents, spraying with water, stockpile management, temperature monitoring	Reduce	Mature	Covering/sealing: operating costs, integration with existing stockpiling infrastructure/methods, re-handling (i.e. adding/removing covers)	-	-
Vegetation removal	Best practice management	Minimising vegetation clearing, re-use of the removed vegetation, rehabilitation of land as quickly as possible	Avoid/reduce	Mature	-	-	• Reduction of dust • Improved biodiversity

Sources: USEPA (2018)

Table 3.14 Existing measures for scope 2 emissions

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness	Potential barriers	Risks or disadvantages	Co-benefits
Purchased electricity	Various energy efficiency measures	Reduction of electricity use through, for example, variable-speed drives on motors, the use of the latest high-efficiency air conditioners, fans and pumps, ventilation system maintenance improvements, timers on air conditioning units and lights	Reduce (improved efficiency of processes)	Mature	-	-	-
	Renewable grid electricity	Source renewable energy via independent power provider	Substitute (reduced emissions intensity of electricity source)	Mature	- Lack of supply of firmed renewable electricity - Limited incentives under the Safeguard Mechanism	-	-

Sources: Crittenden et al (2016); FBICRC (2023); CCA (2024)

Table 3.15 Emerging measures for scope 1 emissions – fugitive methane

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness (time to market)	Potential barriers	Risks or disadvantages	Co-benefits
Active underground mines							
VAM	Catalytic oxidation	Destruction of VAM through RCO	Reduce (reduces GWP through conversion of CH ₄ to CO ₂)	R&D to demonstration (2030-2035)	- High CAPEX - Technology development needed - Safety regulation and approvals process - Difficult to integrate in existing facility - Lack of technical expertise at mines	- Air pollution - Noise - Safety - Residual CO₂ emissions	-
	CH ₄ enrichment	Increasing CH ₄ concentration for subsequent utilisation	- (only supports CH ₄ use)	R&D (>2030)	- Technology not commercially available - High CAPEX and OPEX	Consumes energy	-

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness (time to market)	Potential barriers	Risks or disadvantages	Co-benefits
Drainage gas	Utilisation for purposes other than electricity generation	Capture of gas through boreholes, followed by utilisation for purposes other than electricity generation at or near a mine	Reduce (use of gas reduces GWP through conversion of CH ₄ to CO ₂)	R&D to mature, depending on use	• Cost to purify gas for utilisation • Low or variable CH₄ concentrations • Lack of supporting infrastructure for utilisation	• Residual CO₂ emissions	• Uses CH₄ productively
Closed underground mines							
Fugitive CH ₄	Flaring	Capture of gas through boreholes, followed by combustion in a flare	Reduce (reduces GWP through conversion of CH ₄ to CO ₂)	Mature	• Lack of financial incentive • No regulatory driver • Decreasing CH₄ output over time	• Air pollution and noise - • Safety (e.g. air ingress) • Residual CO₂ emissions	
	Utilisation (any purpose)	Capture of gas from vents, followed by utilisation	Reduce (use of gas reduces GWP through conversion of CH ₄ to CO ₂)	R&D to mature, depending on use	• Cost to purify gas for utilisation • Low or variable CH₄ concentrations • Lack of supporting infrastructure for utilisation	Residual CO ₂ emissions	Uses CH ₄ productively
Active surface mines							
Drainage gas	Flaring	Capture of gas through boreholes, followed by combustion in a flare	Reduce (reduces GWP through conversion of CH ₄ to CO ₂)	R&D to demonstration. Not implemented in NSW	• Gas reservoir properties can make it technically difficult and expensive to extract CH₄ • Difficulties posed by continuously changing mining operations • No enabling regulatory environment • Lead time required to drain gas ahead of mining operations	• Air pollution and noise - • Safety • Residual CO₂ emissions	

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness (time to market)	Potential barriers	Risks or disadvantages	Co-benefits
	Utilisation (any purpose)	Capture of gas through boreholes, followed by utilisation	Reduce (use of gas reduces GWP through conversion of CH ₄ to CO ₂)	R&D	• Typical gas reservoir properties can make it technically difficult and expensive to extract CH₄ • Difficulties posed by continuously changing mining operations • Cost to purify gas for utilisation • Low or variable CH₄ concentrations • Lack of supporting infrastructure for utilisation	• Residual CO₂ emissions	• Uses CH₄ productively

Post-mining activities

Coal stockpiles	None identified	-	-	-	-	-	-
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Sources: CCA (2024)

Table 3.16 **Emerging measures for scope 1 emissions – diesel combustion**

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness (time to market)	Potential barriers	Risks or disadvantages	Co-benefits
Haul trucks	Electrification	On-board: hybrid, BEV	Reduce (with renewable electricity)	R&D to demonstration (>2030-2035) (possibly earlier for underground mines)	All technologies • Technology development needed • Lack of supply of vehicles • Lack of supply of firm renewable electricity • Integration of the required supporting infrastructure to existing mines • High CAPEX	All technologies • Risk of collision due to quiet operation • New worker safety issues Batteries • Battery efficiency affected by climate • Battery fires	All technologies • Reduced noise and air pollution • Reduced OPEX (energy and maintenance costs) • Reduced ventilation (energy) need for underground mines • Reduced oil/grease use
		On-board: fuel cell/H ₂			Fuel cell/H ₂ • Lack of supply of renewable hydrogen • High cost of renewable hydrogen		

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness (time to market)	Potential barriers	Risks or disadvantages	Co-benefits
Other heavy mining vehicles and equipment	Electrification	Tethering: connection to a fixed electricity supply			Tethering • Impractical for haul trucks at surface coal mines due to distances involved		
		Trolley assist: connection to an overhead cable to power an electric drive			Trolley-assist • Likely to be impractical for surface coal mines due to evolving mine plans		
		General electrification of mine equipment other than haul trucks	Reduce (with renewable electricity)	R&D to demonstration (>2025)	All technologies • Technology development needed • Lack of supply of vehicles • Lack of supply of firmed renewable electricity • Integration of the required supporting infrastructure to existing mines • High CAPEX	All technologies • Battery efficiency affected by climate • Battery fires • New worker safety issues	All technologies • Reduced noise and air pollution • Reduced OPEX (energy and maintenance costs)
		Tethering: connection to a fixed electricity supply		Demonstration to mature (>2025)	Tethering • Requires high-voltage infrastructure • Challenged by on-board electric power • Restricted operational flexibility	Tethering • Safety (high-voltage cables)	
		Automation	Reduce	Demonstration to mature	• Technology development needed • High CAPEX	• New worker safety issues • Elimination of jobs	• Improved safety
All vehicles and equipment	Renewable fuels	Switching to renewable diesel	Substitute	Demonstration to mature (>2025)	• High OPEX • Lack of supply, and possible competition from other sectors	-	-

Sources: CCA (2024); Issa et al (2023); FBICRC (2023); Advisian (2022)

Table 3.17 Emerging measures for scope 1 emissions – other processes

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness (time to market)	Potential barriers	Risks or disadvantages	Co-benefits
Petrol combustion	None identified	-	-	-	-	-	-
ANFO combustion	Waste oils or renewables	Alternative fuels	Substitute	Demonstration (>2025)	- Compliance with regulations - Market availability	- Blasting safety - Performance consistency	- Cost savings - Re-use of waste oils
Oils, greases	Alternative lubricants	-	Substitute	-	-	-	-
Fugitive SF ₆	None identified	-	-	-	-	-	-
Coal oxidation (stockpiles)	None identified	-	-	-	-	-	-
Vegetation removal	Pyrolysis	Thermal degradation of vegetation using low-oxygen technology to produce biochar	Avoid (if the alternative is burning) and reduce	Demonstration to mature	Market availability	- Feedstock variability - Fire risk	Biochar can be used (e.g. soil management, manufacturing of bio-oil and syngas, farming and energy production)

Sources: USPEA (2020); Al-Rumaihi et al (2022)

Table 3.18 Emerging measures for scope 2 emissions

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness (time to market)	Potential barriers	Risks or disadvantages	Co-benefits
Purchased electricity	On-site renewable electricity generation	Wind, solar or geothermal power	Substitute	Demonstration to mature	- High CAPEX - Regulatory approvals - Space constraints	Reliability (dependency on weather)	- Cost savings - Reduces the risk of supply disruptions

GHG source	Mitigation measure	Notes	Mitigation hierarchy	Technology readiness (time to market)	Potential barriers	Risks or disadvantages	Co-benefits
	On-site energy storage (batteries)	Facilitates the wider electrification of mining operations	- (supports general electrification)	Demonstration to mature (>2025)	Battery size and robustness needed for mine sites	- Replacement potentially every few years leading to more GHG lifecycle emissions and costs - Safety (overheating leading to fires or explosions) - Environmental (leaks causing contamination of water/soil)	- Cost savings particularly during peak demand times - Backup power supply - Integration with renewable energy - Reduced noise and air pollution

Sources: CCA (2024)

3.10 Emerging carbon capture and storage techniques

The end product of most treatments and uses of methane is CO₂, and the release of this CO₂ will still have an impact on global warming. Although it is outside the scope of the study, it is therefore worth mentioning the potential future role of engineered carbon capture and storage (CCS)⁵³ with respect to NSW coal mines.

3.10.1 Techniques

In general terms, CCS involves the capture, transport and long-term storage or utilisation of CO₂ from industrial processes, so that it is not released to the atmosphere. These processes are briefly summarised below.

Various different technologies can be used to capture CO₂ at the source. For large industrial point sources (e.g. power plant), CO₂ can be captured pre-combustion or post-combustion. In pre-combustion capture, fossil fuel is partially burned in a gasifier, and CO₂ can be captured through syngas separation in relatively pure form. In post-combustion capture, CO₂ is removed from the exhaust gases. Another process is oxy-fuel combustion, where fuel is burned in a nearly pure-oxygen environment, rather than air, which results in a more concentrated stream of CO₂. It is also possible to capture CO₂ directly or indirectly from the open atmosphere. Most operating direct air capture (DAC) systems employ either a liquid or solid sorbent to capture dilute CO₂ from ambient air. Indirect air capture (IAC) enhances natural carbon capture processes such as photosynthesis and carbon mineralisation (McLaughlin et al 2023).

Following capture, CO₂ is transported to suitable storage sites, by pipeline, sea, road or rail. CO₂ can then be stored in several different ways, including:

- Geological sequestration, involving the injection of CO₂ into geological formations. CO₂ is converted into a high pressure, liquid-like form known as ‘supercritical CO₂’. Potential storage sites include depleted oil reservoirs, un-mineable coal seams⁵⁴, saline formations, depleted gas reservoirs and hydrocarbon-bearing shale (McLaughlin et al 2023).
- Mineral carbonation, where the captured CO₂ reacts with naturally occurring minerals to fix it as carbonates (this process may be considered a method for both capture and storage of CO₂) (McLaughlin et al 2023). However, the reactions are very slow under normal conditions. There are several methods to achieve mineral carbonation, one of which is ‘enhanced weathering’⁵⁵, which may be cheaper at some mine sites than other locations (NSW OCSE 2023).
- Ocean storage, which aims to use the ocean’s natural chemical and biological processes to absorb and store more CO₂ from the atmosphere. ‘Abiotic’ approaches include alkalinity enhancement, electrochemical techniques and artificial downwelling. ‘Biotic’ approaches typically enhance photosynthesis, so that organisms in seawater take up more CO₂ and store it as biomass. However, these approaches generally remain untested, with significant scientific gaps and risks to the marine environment and coastal communities (Lebling et al 2022).

As an alternative to storage, CO₂ can be used to create products or services. These include fertilisers, food and beverage production, fuels and building materials (e.g. concrete).

⁵³ Also referred to as carbon capture, utilisation and storage (CCUS).

⁵⁴ Coal that is too deep or difficult to mine.

⁵⁵ Enhanced weathering is a chemical approach to removing CO₂. It is a process that aims to accelerate natural weathering by speeding up chemical reactions between rocks, water and air. CO₂ from the atmosphere is permanently stored in solid carbonate minerals.

For underground and open-cut mines in NSW, the potential also exists to relocate captured gas (methane and/or CO₂) from mining seams to neighbouring, gas-undersaturated formations. This is currently the subject of research and development, and trials are being considered.

3.10.2 Limitations for coal mines

In addition to CCS technologies still being at the research stage, there are a number of practical limitations with respect to their application to coal mines in NSW, including the following:

- CCS is mostly being considered for CO₂. In the absence of specific approaches for methane, this would require the methane from coal mines to be converted into CO₂ prior to storage. Most of the mitigation methods (and uses) for methane discussed in this report would ultimately result in CO₂, but perhaps not in sufficient quantities to justify CCS.
- CCS requires a comparatively high concentration of CO₂. Industries that emit relatively pure CO₂ – such as ammonia production, natural gas processing, hydrogen production and cement manufacture – are best suited to the implementation of CCS (CCA 2024). Coal mines, on the other hand, do not generally emit CO₂ at high concentrations (other than mines with high CO₂ gas contents).
- Enhanced rock weathering is also more suitable for mineral mining (e.g. tailings could react with CO₂) than coal mining. Azadi et al (2019) argue that the abundance of mining wastes and processing by-products such as fly ash, red mud and mine tailings in Australia creates an opportunity for carbonation in its mining sector, but these are not related to coal mining per se (fly ash is a product of coal-fired power generation).
- Access to CO₂ storage sites is critical to the adoption of CCS (CCA 2024). At present in NSW, there are few appropriate geological sites to permanently and safely store CO₂. However, this is an area of ongoing research for Coal Innovation NSW⁵⁶.
- Techniques such as underground storage and enhanced rock weathering are only likely to be suitable for deployment on-site, once the mine has ceased operating (i.e. in the closure phase).
- Underground storage at coal mines may only be suitable in specific situations (e.g. deep mines).
- There are environmental (and other) risks associated with geological CO₂ storage, especially in relation to water reservoirs.

3.10.3 The future of carbon capture and storage in NSW

At this stage, CCS is an emerging technology, and the cost is still very high (UNECE 2024). To achieve large-scale uptake in Australia, a rapid acceleration of funding support will be needed, both for basic research and for implementation of pilot projects (CCA 2024).

The application of CCS in NSW would require detailed and robust risk assessments, reinforced by an effective sub-surface regulatory framework, including appropriate groundwater and surface water protection measures and effective monitoring regimes.

⁵⁶ <https://www.resources.nsw.gov.au/invest-nsw/coal-innovation-nsw/carbon-capture-and-storage>

4 Industry scan

4.1 Background and objectives

To support the development of the Mitigation Guide, in late 2024 and early 2025 the EPA and EMM conducted a consultation exercise with the NSW coal mining industry, referred to here as an ‘industry scan’.

The objectives of the industry scan were as follows:

- Providing a better understanding of what the NSW coal mining sector is currently doing to mitigate GHG emissions at the company and/or site-level. This helped with the following:
 - Understanding the current state of implementation of mitigation measures in NSW, as well as measures that are being considered for future implementation.
 - Ensuring that the Guide is based on experience that is more up to date, and more specific to NSW, than the content of the publicly available literature.
- Identifying the most important factors that influence the decision to implement (or not) specific mitigation measures at coal mines in NSW, such as:
 - Technical drivers, barriers, limitations and opportunities (e.g. availability of technology, effectiveness at GHG reduction).
 - The advantages and disadvantages of specific mitigation measures.
 - Specific mine conditions that have influenced decision-making (e.g. methane content of coal seams and ventilation air, supporting infrastructure). Although the emphasis was on technical aspects, market and regulatory conditions were also considered.
 - Cost.
- Identifying potential case studies to support the Mitigation Guide. These were not readily available for NSW.

In addition, it was considered that the industry scan could potentially help to identify where additional government funding on GHG mitigation could be targeted (e.g. feasibility studies in NSW for emerging and novel technologies).

4.2 Methodology

Coal mining companies were invited to attend an on-line interview with the EPA and EMM, and/or complete an Excel-based survey form off-line. To minimise duplication, a parent company had the option of using one form to represent all its mines, or to use one form per mine type (e.g. open-cut mines, gassy underground mines, low-gas underground mines, closed mines).

4.2.1 Survey form

An Excel form for use in the industry scan was developed by EMM. The form was designed to facilitate consultation with the industry in relation to mitigation measures, and to provide a standardised template for responses. The form included multiple drop-down menus and spaces for free text entry.

The form included the following sections:

- Background information relating to the Mitigation Guide and the industry scan, instructions for completing the form, and any information that had already been provided to the EPA.
- PART 1: General information

This included:

- General mine details (parent company and mine name), mine type and stage.
- Any general comments that were relevant to the development of the Guide, such as what additional mitigation measures need to be included, or what steps need to be taken when implementing mitigation measures.
- Whether the company would be willing to provide examples of case studies for use in the Guide and, if so, what the case studies would be.

- PART 2: Scope 1 emissions - fugitive methane

This part dealt with the various sources of (scope 1) fugitive methane at coal mines, including drainage and ventilation. The form used drop-down menus to characterise fugitive methane at the mine, to identify mitigation measures and their status:

- Implemented: where a given mitigation measure is currently implemented.
- Not implemented: where a given mitigation measure is not currently implemented.
- Considered: where a given mitigation measure is being considered for future implementation.
- Rejected: where a measure has been evaluated but rejected for implementation (based on current considerations).
- Other: where some other condition applies (e.g. a given measure has previously been implemented but subsequently decommissioned).

The utilisation of any captured methane was also considered.

Free-text entry boxes were used for each source to explain why the mitigation measures and uses were selected, and why other measures were deferred or rejected. In addition, any other information that could inform the Guide can be provided (please see examples).

- PART 3: Scope 1 emissions - diesel combustion

This part dealt with scope 1 emissions from diesel combustion at the mine, and in relation to different sources such as haul trucks, other heavy mining equipment, light vehicles and other equipment. Mitigation measures were characterised in the same way as those for fugitive methane.

- PART 4: Scope 1 emissions - other minor sources

This part dealt with the various other minor sources of GHGs at the mine. For most coal mines these will be relatively small contributors to total GHG emissions. Such sources included petrol combustion, blasting, use of oils and greases, SF₆ leaks, coal oxidation and vegetation removal.

- PART 5: Scope 2 emissions

This part dealt with the status of mitigation measures for scope 2 emissions associated with the purchase of electricity from the grid.

- PART 6: Scope 3 emissions

This part allowed the company to describe any measures that have been implemented (or will be implemented) to reduce scope 3 emissions. Such measures would include, for example, contributions to research and development, reduction of embodied emissions and sustainable procurement.

4.2.2 Interviews

In total, nine mining companies were interviewed between October 2024 and January 2025.

4.2.3 Analysis

All the responses from the interviewees, including the completed forms and notes from the interviews, were combined into a single spreadsheet. The spreadsheet was then used as the basis for the analysis.

NB: The results presented below are essentially 'as reported' by interviewees. There has been no verification of these responses by EMM. For the purposes of this document, the results of the industry scan have been aggregated (or generalised) to maintain the confidentiality of individual responses.

4.3 Results: mining company interviews

4.3.1 General comments

The interviewees supplied various general views and comments of relevance to the development of the Mitigation Guide, and these are summarised below.

- General principles
 - In general, GHG mitigation for coal mines should consist of practices to identify sources, quantify emissions, reduce emissions where feasible, and monitor/review for potential changes in the feasibility of existing and emerging initiatives.
 - The Mitigation Guide should reflect a collation of industry practices, and should not seek to dictate what represents 'best practice' or what may or may not be suitable for individual mining operations.
- Variability in mine characteristics
 - Coal mines have a wide range of methane emissions intensity, driven by geology, the age of the mine and mining methods. As such, activities to reduce emissions have a site-specific context and application. Mitigation measures will also have a varying feasibility (and effectiveness) between and within mines. Due to this inherent variability, there is no 'one size fits all' approach for mitigation.
 - Some collieries have been operating for decades, with the majority of emissions being due to legacy issues and permeable seams, rather than active mining.
- Safeguard Mechanism and NGERs
 - The requirements of the Mitigation Guide should strike a balance with the requirements of the Safeguard Mechanism and NGERs.

- Potential emission-reduction measures at coal mines are already assessed in detail for reasons of safety and cost-effectiveness, and as part of standard business processes. Under the Safeguard Mechanism, there is an incentive to assess and implement measures where practicable and feasible.
- Remaining life of mine
 - Where mines have relatively short remaining life, emission-reduction initiatives that require significant capital will be challenging to justify.
 - Mine closure scenarios need to be accounted for in the development of mitigation measures.

4.3.2 Reported mine characteristics

The characteristics of the mines included in the industry scan are summarised in Table 4.1 (underground), and Table 4.2 (surface). These characteristics include the main scope 1 GHG emission sources and the characteristics of the coal seam and (for underground mines) the ventilation air.

For the active underground mines, VAM was reported as a major GHG source, at between 65% and 99% of scope 1 emissions, depending on the mine. Drainage gas, where relevant, was reported as another important source. The reported gas content of coal seams ranged from less than 0.25 m³/t to 20 m³/t. The methane content of the drainage of the coal seam gas was also variable. For the ventilation air from active underground mines, the reported methane concentration was up to 0.4%.

Other underground mines were either closed or in care and maintenance. The information provided for these was limited, but for the mines included it indicated that methane emissions would be relatively low.

At surface mines, the reported main contributor to emissions was diesel combustion, with a fugitive methane contribution that could be high or low, depending on the mine. The reported gas content of coal seams was generally low compared with underground mines.

Table 4.1 **Reported characteristics: underground mines**

GHG emission sources (scope 1)	Coal seam characteristics		Ventilation air characteristics	
	Gas content	Methane content	Methane concentration	Air flow
• VAM from 65% to almost 100% • Drainage from <20% to 30%	<0.25 m ³ /t to ~20 m ³ /t	15% to ~98%	<0.1% to ~0.4%	~180 m ³ /s to 850 m ³ /s

Table 4.2 **Reported characteristics: surface mines**

Main GHG emission sources	Coal seam characteristics	
	Gas content	Methane content
• Diesel • Fugitive methane (major or minor) • Electricity	Low to 4 m ³ /t	Typically low, but can be highly variable

4.3.3 Reported mitigation for scope 1 emissions: fugitive methane

For the active underground mines in the industry scan, the main mitigation measures reported as being currently implemented or being considered are:

- Pre/post drainage with flaring and, in some cases, power generation from drainage gas.
- RTO. One interviewee had previously implemented RTO, but had ceased the operation of it. Other interviewees were either still considering implementation, or considered it to be unfeasible, mainly due to low methane concentrations in ventilation air, safety concerns and a short remaining life of mine.

The following comments were made by interviewees:

- RTO
 - RTO currently requires a minimum methane concentration of 0.2-0.3% for sustained operation.
 - RTO has significant safety barriers that need to be addressed in Australia. To date, risk mitigation has focussed on reducing the likelihood of an accident, but the consequences remain unaddressed.
 - Interviewees were aware of VAM enrichment for RTO treatment (i.e. adding drainage gas to VAM to allow sustained operation). However, this was not a preferred option, as the drainage gas could otherwise be used for power generation where this is practicable.
 - The application of RTO would be easier if systems could be modular and transferrable between sites.
- Gas drainage at surface mines
 - Although some surface mines were considering drainage, flaring and gas utilisation, these measures had either not yet been implemented, or had been deferred.
 - Open-cut pre-drainage was considered to be an emerging technology, and the interviewees were not aware of it being conducted anywhere globally for emissions reduction.
 - Identified barriers to drainage included multiple seams of varying thickness, typically shallower depth and lower gas content than underground mines. These factors would add to complexity and cost, and make it challenging to achieve feasible, economic gas recovery for emissions reduction.
 - There are carbon accounting barriers that affect how an emission-reduction benefit is quantified.
 - Drainage may be challenging at open-cut mines due to active workings.
- Gas utilisation
 - Interviewees were not aware of any instances where VAM had been utilised productively, either with or without enrichment.
 - Funding is required for the introduction of infrastructure (e.g. pipelines) to support gas utilisation.

For mitigation of fugitive methane at underground mines in care and maintenance or closed, the information from the industry scan was limited. Reported mitigation currently focuses on sealing and flooding.

4.3.4 Reported mitigation for scope 1 emissions: diesel combustion

i Heavy mining equipment

For active underground mines in the industry scan, where diesel combustion is a relatively small contributor to total emissions, the reported mitigation effort is quite limited. However, the use of electric equipment – especially conveyors for transporting coal – was reported as common. Some mines reported that they continue to monitor and consider existing and emerging technologies for emissions reduction, including renewable fuels.

The industry scan responses indicated that mitigation of diesel combustion at surface mines is a important consideration. It was noted that minimising diesel consumption is standard business practice, and typically involves a combination of the following:

- Mine planning
 - Optimisation of fleet and haulage routes to ensure efficiency of equipment travel where possible. It was noted that, as a rule of thumb, diesel use should be around 1 litre per bank cubic metre (BCM).
 - Consideration of the fuel efficiency of all mobile and fixed equipment during procurement. Use of energy-efficient vehicles and equipment, including through equipment replacement over time.
- Operation
 - Ensuring haul trucks are fully loaded for each load prior to hauling to maximise productivity.
 - Servicing/maintenance.
 - Driver training for fuel efficiency.

Interviewees reported that electrified in-pit crushing and conveying was not considered to be appropriate surface mines with highly variable haul routes.

Biodiesel and renewable diesel have not been implemented for a number of reported reasons, including high cost compared with conventional diesel, the lack of supply, and the lack of detailed studies of their effects.

Interviewees reported some large equipment at surface mines is already electrified (tethered), such as draglines and shovels, but the electrification of haul trucks is an emerging technology. Trolley assist has effectively been rejected due to the changing nature of the mine layout. Few respondents specifically mentioned automation, although one interviewee argued that it may not necessarily result in emissions reduction.

The following additional comments were made by interviewees with respect to electrification:

- At underground mines the equipment is mostly electrified (both mining equipment and haulage/conveyor equipment). Diesel combustion is therefore minimised/avoided.
- Battery electric and hybrid electric mine vehicles currently have a low technological readiness, but a larger-scale roll-out can be expected from 2035 (possibly earlier for hybrids). Fuel cell mine vehicles have a low technological readiness.
- The larger mining companies have better access to the latest technology, and are able to conduct more trials. There are commercial barriers for small- to mid-tier mining companies.
- Electric haul trucks can use 10 MW of power in 30 minutes, and there is not energy supply to sites to operate them. The electricity supply would need to be augmented.
- There are currently skill shortages in relation to maintaining and operating electric vehicles.

ii Other vehicles and equipment

Diesel combustion in other (mainly 'light') vehicles and equipment was reported as a minor or negligible contributor to GHG emissions at all mines. This section therefore summarises the initiatives that are currently underway. These initiatives, and some of the issues mentioned, are identified in Table 4.3. In some cases, the barriers that apply to heavy equipment also apply to light equipment (e.g. cost, availability of technology).

Table 4.3 Reported mitigation for scope 1 emissions: other diesel vehicles and equipment (all mines)

Emission source	Mitigation measure	Current approaches	Barriers
Light vehicles	BEVs and HEVs	- Investigation of options. - Trials (surface and underground). - Implementation.	- Capital cost (\$150-\$200K). - Availability of mine-specification 4WD vehicles. - Reliability.
Buses	Battery electric buses	- Investigation of options. - Trial of electric vehicle for underground personnel transport. - Implementation of electric surface bus for personnel transport.	No information.
All vehicles	Biodiesel/ renewable diesel	- Working with fuel suppliers to understand options. - Trial use of hydrotreated vegetable oil fuel.	- No renewable diesel supplies available in Australia. - Cost prohibitive.
Pumps and compressors	Electrification	Already electrified at some mines, where feasible.	No information.
Generators	Alternatives	- Reducing use of diesel generators, with transition to grid power. - Investigating hydrogen fuel cell gen sets. - Reviewing solar generators.	No information.

4.3.5 Reported mitigation for scope 1 emissions: other minor sources

The other minor scope 1 emission sources, and the mitigation measures reported for these in the industry scan, are given in Table 4.4. All interviewees reported that these sources have either zero emissions or have a negligible contribution to emissions. Consequently, the information provided was relatively brief. Several interviewees reported they were investigating emerging mitigation measures for these sources, or were in the process of conducting trials.

Table 4.4 Reported mitigation for scope 1 emissions: other minor sources (all mines)

Emission source	Mitigation measures
Petrol combustion	- As petrol use is negligible at coal mines, the measures in place are limited. - Some trials of fuel additives are being conducted.
Use of fossil fuel in blasting	- Some interviewees reported that they were investigating renewable fuel. - It was reported that the use of biodiesel affects efficiency of blasts.
Oil and grease use	- Most interviewees reported that they were recycling oils and greases. - Bio-lubricants have been investigated in some cases, but have not been implemented due to concerns about engine/equipment warranties being voided.

Emission source	Mitigation measures
Fugitive SF ₆	- Accounting/tracking is commonly used. - LDAR is used at some mines. - Equipment upgrades are being considered for future implementation.
Coal oxidation	- Standard stockpile management is applied. - Coal oxidation is managed for safety and economic reasons.
Vegetation removal	- Rehabilitation is completed progressively. - Clearing is minimised wherever possible, and vegetation is mulched for use with topsoil. - Vegetation is re-used in some cases.

4.3.6 Reported mitigation for scope 2 emissions

For scope 2 emissions, in general, interviewees reported that:

- variable speed motors on, for example, fans, conveyors and pumps, are implemented where possible
- energy efficiency is taken into account for all new major electrical equipment during procurement
- PPAs for renewable energy have been used, or are being considered for commercial viability and practicality
- on-site renewable energy has been implemented at some mines, but barriers at other mines include low cost-effectiveness, insufficient resource (e.g. wind) and a lack of available space.

The following additional comments were made by interviewees:

Renewable grid electricity

- With respect to PPAs, the remaining life of mine is an issue. Costs are high, and it can be difficult to attract investment.

On-site renewable energy

- It was noted that, where a mine is supplying gas to a third party for electricity generation, the installation of on-site renewables effectively represents competition, and is therefore not viable.

4.3.7 Mitigation for scope 3 emissions

Relatively little information was provided on the mitigation of scope 3 emissions. Several interviewees reported they are in the early stages of quantifying their scope 3 emissions.

The approaches that were mentioned by interviewees included:

- use of local equipment and materials suppliers, as well as contractors and consultants where practicable to reduced transport emissions
- encouraging direct suppliers to pursue net-zero GHG emissions for their operations
- working with thermal coal customers to looking at technologies such as ammonia and biofuel injection to reduce coal consumption and increase energy output
- supporting industry to develop technology to reduce the GHG emissions intensity of power generation (e.g. boiler efficiency, pellets), steelmaking and shipping

- exploring the potential for carbon capture, utilisation and storage, including sequestering CO₂ in materials (e.g. concrete).

Some of the reported barriers to addressing scope 3 emissions included processes that were outside the operational control of the mines, difficulty in obtaining data for upstream and downstream activities, and a short remaining life of mine.

4.3.8 Case studies and trials

The industry scan provided some options for case studies and trials that could be used as examples to support Mitigation Guide. These included:

- regenerative thermal oxidation trials
- electricity generation from methane captured from gas drainage at underground mines, including use of electricity either onsite or for export
- trials of gas separation to obtain methane for power generation, and high-grade CO₂, which can be either utilised, sold, or stored
- small-scale trials of emerging biological carbon capture and use technologies
- on-site renewable energy (solar facilities)
- electrification of large mining equipment (ore mines)
- regenerative agriculture and traditional forestry to generate carbon offsets.

No specific opportunities for potential new government funding were raised in the industry scan, although several interviewees expressed an interest, and requested further information on the process to be followed.

5 Summary

5.1 Background

This report has presented the findings of a literature review and industry scan relating to the mitigation of GHG emissions in the NSW coal mining sector. The study addressed specific mine types, mine stages, mining activities, GHGs, emission scopes and mitigation measures.

The literature review covered international guidance and measures relating to the mitigation of GHG emissions from coal mines. It described various aspects, including coal mining processes and emission sources, existing guidance, existing and emerging mitigation measures for managing GHG emissions at coal mines, and methane utilisation. A qualitative analysis of the existing and emerging mitigation measures in the literature was conducted.

The industry scan involved a consultation with coal mining companies in NSW to better understand what the coal sector is currently doing to mitigate emissions and to identify the most important factors that influence decision-making, and to identify potential case studies.

5.2 Literature review

5.2.1 Coal mining processes and emissions in NSW

In the financial year 2021–22, the NSW coal mining sector was responsible for 13.9 Mt CO₂-e of direct (scope 1) emissions, or 12% of state-wide GHG emissions. Fugitive emissions, and fuel combustion emissions associated with mining machinery, accounted for almost all the emissions from the sector. Most of the emissions from coal mining were associated with fugitive methane. The main components were underground mine ventilation (47%), fugitive emissions from surface mines (12%), and diesel equipment (29%). Emissions from closed mines (8%) were also significant.

For underground mines, fugitive emissions have followed a downward trend historically, and this is projected to continue in the future. By 2040, emissions are projected to be around 40% lower than those in 2005 in NSW, and around 50% lower in Australia. Emissions from surface mines are more stable over time, changing little between 2005 and 2040.

Scope 2 emissions from all mining in NSW in 2021–22 were 2.9 Mt CO₂-e/year.

5.2.2 Mitigation for fugitive methane

For underground mines, the venting of drainage gas or ventilation air methane (VAM) to the atmosphere is undesirable, given the high global warming potential (GWP) of methane.

The main **existing** mitigation options for methane mitigation at underground mines are:

- flaring of drainage gas
- regenerative thermal oxidation (RTO) of VAM.

These convert methane to carbon dioxide (CO₂) and effectively reduces its GWP by around 90%. However, the methane is not used for other purposes (e.g. electricity generation). Gas flaring is used at some coal mines in Australia. RTO has not yet been widely adopted at coal mines in Australia; barriers to implementation identified by industry include low methane concentrations in VAM, safety and cost. The technology involved will vary with the mine type and source type (e.g. drainage gas or VAM; underground mines or surface mines), and each circumstance may be unique.

The main **emerging** measure for fugitive methane emissions at underground mines is RCO, which has the potential to operate at lower temperatures, higher air flow rates and lower VAM concentrations than RTO. Another emerging technology is methane enrichment using, for example, gas separation, although it is not expected to be commercially available in the near future.

The capture and treatment of fugitive methane from surface coal mines is an emerging technology. The barriers to implementation in NSW include gas reservoir properties making it technically difficult and expensive to extract methane, and difficulties posed by continuously changing mining operations.

For both underground and open-cut mines, the potential also exists to relocate captured gas from target mining seams to neighbouring undersaturated formations, and trials are currently being considered.

For closed underground mines, existing measures include mine sealing and flooding. Mines going through the decommissioning and closure process have regulatory obligations that include sealing. Flaring is a potential option for treating methane at closed mines, although it is not widely practiced.

5.2.3 Mitigation for diesel combustion

The **existing** measures that can be used to reduce GHG emissions from diesel combustion focus on mine planning, vehicle/equipment procurement to maximise efficiency, and the use of biodiesel. These are coupled with maintenance and training.

With respect to **emerging** measures, a crucial transformation at coal mines will be the electrification of haul trucks and machinery, which should support more efficient and safer mine operations. Electrification will also support the implementation of new and adaptive autonomous technologies. However, electrification will require significant investment in infrastructure and hardware, process changes and training. Some uncertainties include the optimal battery capacity for mining trucks, the best approach for recharging batteries, and the skills and training the workforce will need.

An emerging alternative to fossil diesel is renewable diesel, which has similar properties to fossil diesel. This allows it to be used directly as a fuel in heavy vehicles and machinery, thus overcoming one of the disadvantages of biodiesel. Renewable diesel, although not currently produced commercially in Australia and in limited supply globally, could become a transition fuel while other technologies – such as electrification – are being developed. Renewable diesel (and possibly biodiesel) may also present an option for mines that are unable to feasibly adopt electrification or other measures.

5.2.4 Mitigation for electricity use

The third important source of GHG emissions from coal mines is electricity use (scope 2). Almost all coal mines in NSW are connected to the grid. In the future, the scope 2 GHG emissions from coal mining in NSW will be the net result of (i) changes in coal production (and energy use), (ii) a probable general increase in mine electrification (and electricity demand), and (iii) the reduction in the emission intensity of grid electricity as the NSW grid decarbonises.

The decarbonisation of the NSW grid should reduce scope 2 emissions substantially. In the meantime, it will be possible for mines to reduce their scope 2 emissions through **existing** measures that focus on reducing electricity consumption (e.g. variable-speed drives on motors, and the use of high-efficiency air conditioners, fans and pumps) and/or reducing the emissions intensity of the electricity source. Purchasing electricity generated renewably, rather than from fossil fuels, will reduce the scope 2 emissions from a mine site. Existing mechanisms for this are Power Purchase Agreements (PPAs) for renewable electricity and the surrender of large-scale generation certificates (LGCs) under the Australian Government's Large-scale Renewable Energy Target (LRET). Many NSW coal mines are large users of grid electricity and have obligations to surrender a certain number of LGCs each year to meet their obligations under the LRET.

An **emerging** approach to reducing scope 2 emissions is to incorporate renewable energy sources into mine sites. Examples include wind power, solar power and geothermal power, potentially in combination with energy storage systems. On-site energy storage could be important in facilitating the wider electrification of mining operations. It is likely that battery storage will be the most common approach, but it will have to overcome the challenges of size and robustness needed for mine sites.

5.2.5 Drainage gas utilisation

The productive utilisation of methane in drainage gas can add significant value to a mining operation. The review considered several potential uses for methane, including pipeline gas, chemical feedstock, vehicle fuel, hydrogen production and power generation. The suitability of mine gas for a particular use is primarily dependent on its quality, such as the methane concentration and the stability of supply.

The utilisation of methane for electricity generation at (or near) a mine site is considered to be an existing use. In NSW, drainage gas from coal mines has been used to generate electricity for several decades. All other uses of methane are considered to be emerging, and no examples in Australia were identified in the literature.

5.2.6 Mitigation measures in project assessments

A brief analysis was conducted of the mitigation measures that have been proposed in the GHG assessments for a small selection of coal mine projects.

The five underground mines included in the assessment proposed pre-drainage and flaring, with two mines also considering the use of RTO. No management of GHG emissions from stockpiles was proposed. Each mine also proposed or considered either on-site or off-site power generation using methane.

For open-cut mines, no measures were proposed to address fugitive methane emissions. For diesel combustion, however, all open-cut mines proposed a number of measures, and in particular conventional approaches such as mine planning to reduce material handling, optimising haul routes and payload management. Some mines were implementing, or considering, more efficient mine vehicles and equipment. Some mines were also considering the use of alternative fuels. No open-cut mines were proposing a major electrification of equipment.

No mines were proposing measures to reduce emissions from minor GHG sources such as petrol combustion, SF₆, oils/greases or coal oxidation.

At both open-cut and underground mines, the measures for reducing scope 2 emissions focussed mainly on general improvements in energy efficiency.

5.2.7 Qualitative analysis of mitigation measures

A qualitative analysis of the existing and emerging GHG mitigation measures was conducted. The findings of the analysis are summarised in Table 5.1.

Table 5.1 Analysis of mitigation measures

Emission scope	Emission source	Mine type	Findings
Existing measures			
Scope 1	Fugitive CH ₄	Underground (active)	Gas drainage is already common at NSW coal mines. However, to reduce GHG emissions over the mine life, the drainage gas needs to be treated (see below).
			Flaring of drainage gas is also already common at NSW coal mines, but still results in CO ₂ emissions. However, the GWP of the emitted gas is greatly reduced.
			For the treatment of VAM, RTO is commercially available for VOC destruction. It also results in the conversion of CH ₄ to CO ₂ . The main barriers to implementation at NSW coal mines are applicability, safety and cost.
		Surface (active)	Mitigation measures are not well-established for surface mines.
		Underground (closed)	Standard approaches are passive flooding and sealing. Mines going through the decommissioning and closure process have regulatory obligations that include sealing. There appear to be few incentives to flare emissions from closed mines.
	Diesel combustion	All	Existing measures generally focus on improving the efficiency of mine operations, and are mostly well-established.
	Other minor sources ^(a)	All	Existing measures are well-established, with few significant barriers to implementation.
Scope 2	Purchased electricity	All	Energy efficiency measures can be readily implemented in principle. Almost all coal mines in NSW are connected to the grid, and the emission intensity of grid electricity is projected to decrease significantly.
Emerging measures			
Scope 1	Fugitive CH ₄	Underground (active)	Emerging measures also result in conversion of CH ₄ to CO ₂ . However, it is anticipated that there will be more emphasis on the capture of CH ₄ for productive use (typically electricity generation), primarily through gas drainage.
		Surface (active)	Gas drainage (and treatment) is an emerging technology, and there are barriers to implementation in NSW, including gas reservoir properties making it technically difficult and expensive to extract CH ₄ , and difficulties posed by continuously changing mining operations. Gas drainage may be feasible at some surface mines in NSW.
		All	Relocate captured gas from mining seams to neighbouring undersaturated formations, and trials are currently being considered.
	Diesel combustion	All	Emerging measures focus strongly on mine electrification. It seems likely that the use of on-board batteries will be the preferred option for mining equipment, in combination with a supply of renewable energy for charging. Automation will also probably increase in line with electrification. Renewable diesel could represent an emerging interim measure as other technologies develop. However, a major barrier at the moment is the lack of supply.
	Other minor sources ^(a)	All	There are few emerging measures for other minor processes at coal mines. Two promising options for reducing SF ₆ emissions from high-voltage electrical equipment are vacuum circuit breakers and fluorinated gas circuit breakers.
Scope 2	Purchased electricity	All	Emerging measures focus on renewable on-site electricity generation, in combination with energy storage (probably using batteries).

Notes

(a) Other scope 1 emission sources include the use of petrol, ammonium nitrate fuel oil (ANFO), oils and greases, SF₆ leakage, coal oxidation and vegetation removal. Together, these typically form only a small contribution to total GHG emissions at a coal mine.

5.3 Industry scan

To support the development of the Mitigation Guide, in late 2024 and early 2025 the EPA and EMM conducted a consultation with the NSW coal mining industry, referred to here as an 'industry scan'. Coal mining companies and the peak industry body were invited to attend an on-line interview with the EPA and EMM, and/or complete a survey form off-line. In total, interviews with nine mining companies were conducted.

It should be noted that the results from the industry are presented 'as reported', with no verification by EMM.

5.3.1 Reported mine characteristics

The industry provided information on mine characteristics, including the main scope 1 GHG emission sources and the characteristics of the coal seam and (for underground mines) the ventilation air.

For all active underground mines, ventilation air methane was reported as a major GHG source, at between 65% and 99% of scope 1 emissions, depending on the mine. Drainage gas, where relevant, was reported as another important source. The reported gas content of coal seams ranged from less than 0.5 m³/t to 20 m³/t. The methane content of the drainage of the coal seam gas was also variable. For the ventilation air from active underground mines, the reported methane concentration was up to 0.4%.

Other underground mines were either closed or in the care and maintenance stage. The information provided for these was limited, but for the mines included it indicated that methane emissions would be relatively low.

At surface mines, the reported main contributor to emissions was diesel combustion, with a fugitive methane contribution that could be high or low, depending on the mine. The gas content of coal seams was generally low compared with underground mines.

5.3.2 Reported mitigation for scope 1 emissions: fugitive methane

For the underground mines in the industry scan, the reported main mitigation measures that are currently implemented or being considered are:

- Pre/post drainage with flaring and, in some cases, power generation from drainage gas.
- RTO. One mine had previously implemented RTO, but stopped it. Other mines were either still considering implementation, or considered it to be unfeasible, mainly due to low methane concentrations in ventilation air, safety concerns and a short remaining life of mine.

It was also noted by interviewees that RTO has significant safety barriers that need to be addressed in Australia. Interviewees reported that to date, risk mitigation has focussed on reducing the likelihood of an accident, but the consequences remain unaddressed. In addition, interviewees reported that the application of RTO would be easier if systems could be modular and transferrable between sites.

For mitigation of fugitive methane at underground mines that are closed or in care and maintenance, interviewees reported mitigation currently concentrates on sealing and flooding.

Although some surface mines reported they were considering drainage, flaring and gas utilisation, in most cases these measures had either not been implemented, or had been considered and rejected. Open-cut pre-drainage was considered to be an emerging technology. Reported barriers to drainage included multiple seams of varying thickness, typically shallower depth and lower gas content than underground mines. Interviewees reported that these factors would add to complexity and cost, and make it challenging to achieve feasible, economic gas recovery for emissions reduction. Interviewees reported that drainage may also be challenging at open-cut mines due to active workings.

Interviewees reported that funding is required for the introduction of infrastructure (e.g. pipelines) to support gas utilisation.

5.3.3 Reported mitigation for scope 1 emissions: diesel combustion

At underground mines, where diesel combustion is a relatively small contributor to total emissions, the reported mitigation effort is quite limited. However, the use of electric equipment – especially conveyors for transporting coal – is common.

Interviewees reported that diesel combustion is a more important consideration at surface mines. Minimising diesel consumption is standard business practice, and typically involves a combination of mine planning, operational efficiencies and driver training. Interviewees reported that biodiesel and renewable diesel have not been implemented for a number of reasons, including high cost compared with conventional diesel, the lack of supply, and the lack of detailed studies of their effects.

Interviewees reported that some large equipment at surface mines is already electrified (tethered), such as draglines and shovels, but the electrification of haul trucks is an emerging technology. Trolley assist has largely been rejected due to the changing nature of the mine layout. Few respondents specifically mentioned automation, although one interviewee argued that it may not necessarily result in emissions reduction.

With respect to mine electrification, the following additional comments were made:

- At underground mines the equipment is mostly electrified (both mining equipment and haulage/conveyor equipment). Diesel combustion is therefore minimised/avoided.
- Battery electric and hybrid electric mine vehicles currently have a low technological readiness, but a larger-scale roll-out can be expected from 2035 (possibly earlier for hybrids). Fuel cell mine vehicles have a low technological readiness.
- The larger mining companies have better access to the latest technology, and are able to conduct more trials. There are commercial barriers for small- to mid-tier mining companies.
- Electric haul trucks can use 10 MW of power in 30 minutes, and there is not energy supply to sites to operate them. The electricity supply would need to be augmented.
- There are currently skill shortages in relation to maintaining and operating electric vehicles.

5.3.4 Reported mitigation for scope 1 emissions: other minor sources

The other scope 1 emission sources at coal mines include petrol combustion, blasting, oil and grease use, fugitive SF₆, coal oxidation and vegetation removal. All interviewees reported these sources have either zero emissions or have a negligible contribution to emissions. Consequently, the information provided was relatively brief. Several mines were investigating emerging mitigation measures for these sources, or were in the process of conducting trials.

5.3.5 Reported mitigation for scope 2 emissions

With respect to the mitigation of scope 2 emissions, in general interviewees reported that:

- variable speed motors on, for example, fans, conveyors and pumps, are implemented where possible
- energy efficiency is taken into account for all new major electrical equipment during procurement
- PPAs for renewable energy have been used, or are being considered for commercial viability and practicality. However, barriers include a short remaining life of mine resulting in high cost
- on-site renewable energy has been implemented at some mines, but barriers at other mines include low cost-effectiveness, insufficient resource (e.g. wind) and a lack of available space.

5.3.6 Reported mitigation for scope 3 emissions

Relatively little information was provided on the mitigation of scope 3 emissions. Several mining companies are in the early stages of quantifying their scope 3 emissions. The approaches that were mentioned by interviewees included:

- use of local equipment and materials suppliers, as well as contractors and consultants where practicable to reduced transport emissions
- encouraging direct suppliers to pursue net-zero GHG emissions for their operations
- working with thermal coal customers to looking at technologies such as ammonia and biofuel injection to reduce coal consumption and increase energy output
- supporting industry to develop technology to reduce the GHG emissions intensity of power generation (e.g. boiler efficiency, pellets), steelmaking and shipping
- exploring the potential for carbon capture, utilisation and storage, including sequestering CO₂ in materials (e.g. concrete).

Some of the reported barriers to addressing scope 3 emissions included processes that were outside the operational control of the mines, difficulty in obtaining data for upstream and downstream activities, and a short remaining life of mine.

5.3.7 Other reported issues

No specific opportunities for potential new government funding were raised in the industry scan, although several interviewees expressed an interest, and requested further information on the process to be followed.

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Appendix A

Glossary and abbreviations

A.1 Glossary

A.1.1 Mine types and mine stages

This study uses definitions for coal mine types and mine stages that are, firstly, commonly used in the Australian coal industry and, secondly, relevant to the mitigation of GHG emissions. The definitions of mine types are given in Table A.1. The two general types of coal mine referred to in the study are underground mines and surface (or open-cut) mines. It is noted that, for each general type of mine, various mining methods are in use. The stages of mining that are used in the study are summarised in Table A.2.

Table A.1 Definitions of mine types

Term	Definition	Reference
Underground mine	A coal mine that allows extraction of coal by mining at depth, after entry by shaft, adit or drift, without the removal of overburden.	NGER Measurement Determination 2008
Surface mine or open-cut mine	A mine in which the overburden is removed from coal seams to allow coal extraction by mining that is not underground mining.	NGER Measurement Determination 2008

Table A.2 Definitions of mine stages

Term	Typical activities at this stage	Other terms in use
Active mine	Mining is operational. The following activities may take place: • Pre drainage (surface to in-seam and underground in-seam pre-mining) • Active drainage or post drainage (goaf and adjacent seam drainage) • Operation of mining infrastructure (e.g. ventilation fans, monitoring equipment) • Progressive temporary seals and caps as mining progresses	• Operational mine
	Suspension of operations ^(a) (coal production has ceased). The following activities may take place: • Mine continues to be managed and monitored so that access is still possible • Ventilation fans remain operational • Monitoring continues • Mine workings may begin to naturally flood • May include further temporary seals and caps	• Mine in care and maintenance • Inactive mine^(b)
	Mine closure and rehabilitation process. The following activities may take place: • Gas drainage (post-mining) • Withdrawal of infrastructure (including monitoring equipment) • Mine workings continue to naturally flood • Whole-of-mine sealing • Rehabilitation process	• Mine decommissioning • Mine rehabilitation^(c)
Closed mine	Mine is fully rehabilitated and closed. • Mining lease back has been relinquished back to the government • Flooding continues naturally over time • No monitoring infrastructure • Permanent seals in place	• Decommissioned mine^(d) • Abandoned mine^(b)

Notes

(a) Various coal mines in Australia remain in suspend operations for a number of years, without being fully closed and rehabilitated. Examples in NSW include Russell Vale Colliery, Wongawilli Colliery, Newstan Colliery and Awaba Colliery.

(b) UNECE (2008).

(c) <https://www.resources.nsw.gov.au/resources-regulator/mine-rehabilitation/rehabilitation-compliance>

(d) CER (2024), p.44.

A.1.2 Fugitive methane

Various terms are used in the literature to refer to methane emissions from coal mines, and the use is often ambiguous. Attempts have therefore been made to standardise the terminology. For example, definitions have been provided by the United Nations Economic Commission for Europe (UNECE 2008). For the purpose of this report, the terms in Table A.3 have been defined. These terms are in common use in Australia. Some terms used to refer to the treatment of fugitive methane from coal mines are defined in Table A.4.

Table A.3 Terms used for methane from coal mines in this report

Term	Definition
Fugitive methane ^(a)	CH ₄ emitted by an industrial activity that is not from a point source of combustion, but includes flaring. The definition includes venting of gas from coal mines, gas processing and leaks from pressurised gas lines.
Coal seam gas (CSG)	Gas which is trapped within a coal seam, or the CH ₄ component of the gas. This is sometimes referred to as coal seam methane (CSM) or coalbed methane (CBM).
Ventilation air methane (VAM)	Exhaust gas of a mine ventilation system, which originates across the mine workings and diluted to low concentrations using the outside air, or the CH ₄ component of the gas.
Drainage gas	Gas which is generated by the drainage of (mostly underground) mines.
Coal mine methane (CMM)	Gas which is released during and after mining operations, or the CH ₄ component of the gas (this includes VAM and drainage gas). This is sometimes referred to as coal mine gas (CMG).
Abandoned mine methane (AMM)	Gas which is released from a decommissioned or closed mine, or the CH ₄ component of the gas.
Surface mine methane (SMM)	Gas which is released during surface mining operations, or the CH ₄ component of the gas.
Post-mining methane	Gas which is released after mining (i.e. handling, processing, storage, transportation), or the CH ₄ component of the gas.

Note

(a) Definition from NSW EPA.

Table A.4 Terms used for methane treatment in this report

Term	Definition	Reference
General		
Measure	Any mitigation measures, technology, actions, approach or intervention that is designed to GHG emissions from coal mines.	-
Fugitive methane treatment		
Gas drainage	Methods for capturing the naturally occurring gas in coal seams to prevent it entering mine airways. The gas can be removed from coal seams in advance of mining using pre-drainage techniques and from coal seams disturbed by the extraction process using post-drainage techniques. Also referred to as mine degasification.	UNECE (2016)
Flaring	The combustion of fuel for a purpose other than producing energy (e.g. the combustion of CH ₄ for the purpose of complying with health, safety and environmental requirements).	NGER Measurement Determination 2008
Venting	The disposal of emissions by release to the atmosphere, either intentionally or unintentionally.	CCA (2023)

A.2 Abbreviations

The abbreviations used in this report are defined in Table A.5.

Table A.5 **Abbreviations**

Abbreviation	Definition
AMM	abandoned mine methane
ANFO	ammonium nitrate fuel oil
BEV	battery electric vehicle
CH ₄	methane
CO ₂	carbon dioxide
CO ₂ -e	carbon dioxide equivalent
COP	Conference of the Parties (to the United Nations Framework Convention on Climate Change)
CSG	coal seam gas
CSIRO	The Commonwealth Scientific and Industrial Research Organisation
DPHI	(NSW) Department of Planning, Housing and Infrastructure
EPA	(NSW) Environment Protection Authority
EPL	Environment Protection Licence
FCEV	fuel cell electric vehicle
GHG	greenhouse gas
GWP	global warming potential
HFC	hydrofluorocarbon
HV	hybrid vehicle
IPCC	Intergovernmental Panel on Climate Change
km	kilometres
kW	kilowatt
L	litres
m	metres
Mt	million tonnes
MW	megawatt
MWh	megawatt-hour
N ₂ O	nitrous oxide
NGER	National Greenhouse and Energy Reporting
NSW	New South Wales
PFC	perfluorocarbon

Abbreviation	Definition
PJ	petajoules
RTO	regenerative thermal oxidation
SF ₆	sulfur hexafluoride
SMM	surface mine methane
t	tonne
UN	United Nations
UNECE	United Nations Economic Commission for Europe
USEPA	United States Environmental Protection Agency
VAM	ventilation air methane

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