Abandoned Coal Mine Methane Offset Protocol

Capturing and Destroying Methane from Abandoned Coal Mines

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Table of Contents

Abbreviations and Acronyms

AMM	Abandoned mine methane
CBM	Coal bed methane
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
GHG	Greenhouse gas
MSHA	Mine Safety and Health Administration
NMHC	Non-methane hydrocarbon
QA/QC	Quality assurance/quality control
SSR	Sources, sinks, reservoirs

1 Project Definition

For the purpose of this protocol, offset project is defined as the installation and operation of any device, or set of devices, that result in the capture and destruction of methane gas that would otherwise have been vented to the atmosphere from an abandoned coal mine operation (also referred to as closed). The methane gas associated with abandoned mines will be referred to as “abandoned mine methane” (AMM) throughout the protocol.

Eligible mines under this protocol include two classifications of Mine Safety and Health Administration (MSHA) abandoned mines defined as:

1. Temporarily Abandoned: Coal production has ceased, mine may reopen in the future
2. Permanently Abandoned: Mine has been abandoned for more than 90 days

A project must consist of one or a combination of the following:

1. Installation and operation of new methane capture wells
2. Continued operation of methane capture boreholes or wells that were drilled into the mine workings during active mining

Captured methane can be destroyed on-site or transported for off-site use or destruction (e.g. through gas distribution or transmission pipeline). Regardless of how the methane is utilized, the ultimate fate must be destruction. In addition, project developers may register multiple projects at a single coal mine, e.g. if separate gathering systems or destruction devices are installed at different locations and time periods.

The protocol does not apply to projects that:

- Recover methane from surface coal mines
- Recover methane from coal bed methane (CBM) wells (i.e. wells producing methane from coal seams not within the extents of the mine)
- Recover methane from active underground mines
- Use CO_2 or any other fluid/gas to enhance AMM drainage

1.1 Eligible AMM Recovery Boundary

The project must ensure that the source of the methane destroyed is from an abandoned mine and also from eligible wells.

Step 1: Identify and delineate project mine

The first step is to identify the physical boundary limits of the abandoned mine. The boundaries can be based on final mine maps showing the workings (roadways, mined out areas and seals). These maps are typically submitted to state environmental or mining regulatory agencies upon closure. Final mine maps provide the most accurate underground boundaries of the mine and usually are tied to a state grid or GIS system such that the extent of the mine workings can be transposed to the surface.

Where there is an accumulation of minable coal seams there may be several individual mines overlying and underlying other mines. Each of these mines should be identified and delineated separately.

Step 2: Determining eligible methane and eligible wells

Several wells may be drilled into an abandoned mine in order to economically drain the methane, however each well must be completed only within the mine's defined extents. AMM wells or existing boreholes must be completed within the horizontal and vertical extent of the mine workings, including roadways and gob areas, as defined below.

<u>Horizontal Extent</u>

Horizontal extent is defined by the final mine map submitted to the controlling state agency as noted in Step 1.

<u>Vertical Extent</u>

To be deemed eligible, wells must meet the following criteria:

1. Completed only within the extents of a given mine
    a. Includes the gob area up to 525 feet above the mined seam and wells need to be cased to at least 525 feet above the mined seam
    b. Must not be drilled more than 130 feet below the mine seam
2. The gas from two vertically separated mines cannot be comingled in a wellbore as cross flow between mines can occur

In addition, the following situations are allowable:

1. Gob wells used to drain gas during active mining operations can be used as AMM drainage wells upon mine abandonment
2. The use of underground gas drainage systems networked to supply gas to a single point for use after mine closure is permitted
    a. These may have been put in place to drain gas behind sealed areas or to continue to drain in-mine boreholes of gas as long as they are within the extents of the mine

2 Eligibility

2.1 Location

Only projects located at a single mine in the United States, its territories or on U.S. tribal lands are eligible under this protocol.

2.2 Offset Project Commencement

Offset Project Commencement is defined as the date on which AMM is first destroyed by the project.

2.3 Project Crediting Period

The crediting period for this protocol is ten years.

2.4 Additionality

Projects must satisfy the following tests to be considered additional:

1. The Legal Requirement Test
2. The Performance Standard Test

2.4.1 The Legal Requirement Test

All projects are subject to a Legal Requirement Test to ensure that the GHG reductions achieved by a project would not otherwise have occurred due to federal, state, tribal or local regulations, or other legally binding mandates. A project passes the Legal Requirement Test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions, or other legally binding mandates requiring the destruction of coal mine methane at the project site.

Currently, there are no existing federal, state, tribal or local regulations that require owners of abandoned mines to destroy abandoned mine methane. If an eligible project begins operation at an abandoned mine that later becomes subject to a regulation, ordinance or permitting condition that calls for the destruction of abandoned mine methane, emission reductions may be reported up until the date that the abandoned mine methane is legally required to be destroyed.

2.4.2 The Performance Standard Test

Projects pass the Performance Standard Test by meeting a performance threshold established on an ex-ante basis by this protocol.

There are numerous possible management options and end uses for AMM, ranging from venting, to destruction by flares, combustion in engines or boilers, to injection of the methane into natural gas pipelines. The Performance Standard Test employed by this protocol is based on a national assessment of “common practice” for managing AMM.

The performance threshold for the management of AMM has been demonstrated through low levels of activity penetration as well as the lack of financial viability in the absence of GHG emission reduction credits. Please refer to the document “AMM Background on Performance Standard-Additionality” for details of this assessment.

AMM projects pass the Performance Standard Test if they destroy gas through any end-use management option (e.g. flare, power generation, heat generation, injection into a natural gas pipeline, etc.).

The Performance Standard Test is applied at the time a project applies for registration. Once a project is registered, it does not need to be evaluated against future versions of the protocol or the Performance Standard Test for the duration of its first crediting period.

2.5 Regulatory Compliance

Offset projects must also demonstrate that the project is in material compliance with all federal, state, local, and tribal regulatory requirements that apply based on the offset project location. The project developers are required to disclose in writing to the verifier any and all instances of non-compliance of the project with any law. Offset projects are not eligible for GHG reductions or GHG removal enhancements that are found to be in non-compliance with regulatory requirements due to negligence or intent.

3 Offset Project Boundary – Quantification Methodology

The Offset Project Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that shall be assessed to determine the net change in emissions associated with an abandoned mine methane project. This protocol does not account for carbon dioxide emission reductions associated with displacing grid-delivered electricity or fossil fuel use.

Figure 3.1 provides a general illustration of the Offset Project Boundary, indicating which SSRs are included or excluded from the Offset Project Boundary. All SSRs within the dashed line are accounted for under this protocol.

Table 3.1 provides greater detail on each SSR and information for the SSRs and gases from the Offset Project Boundary.

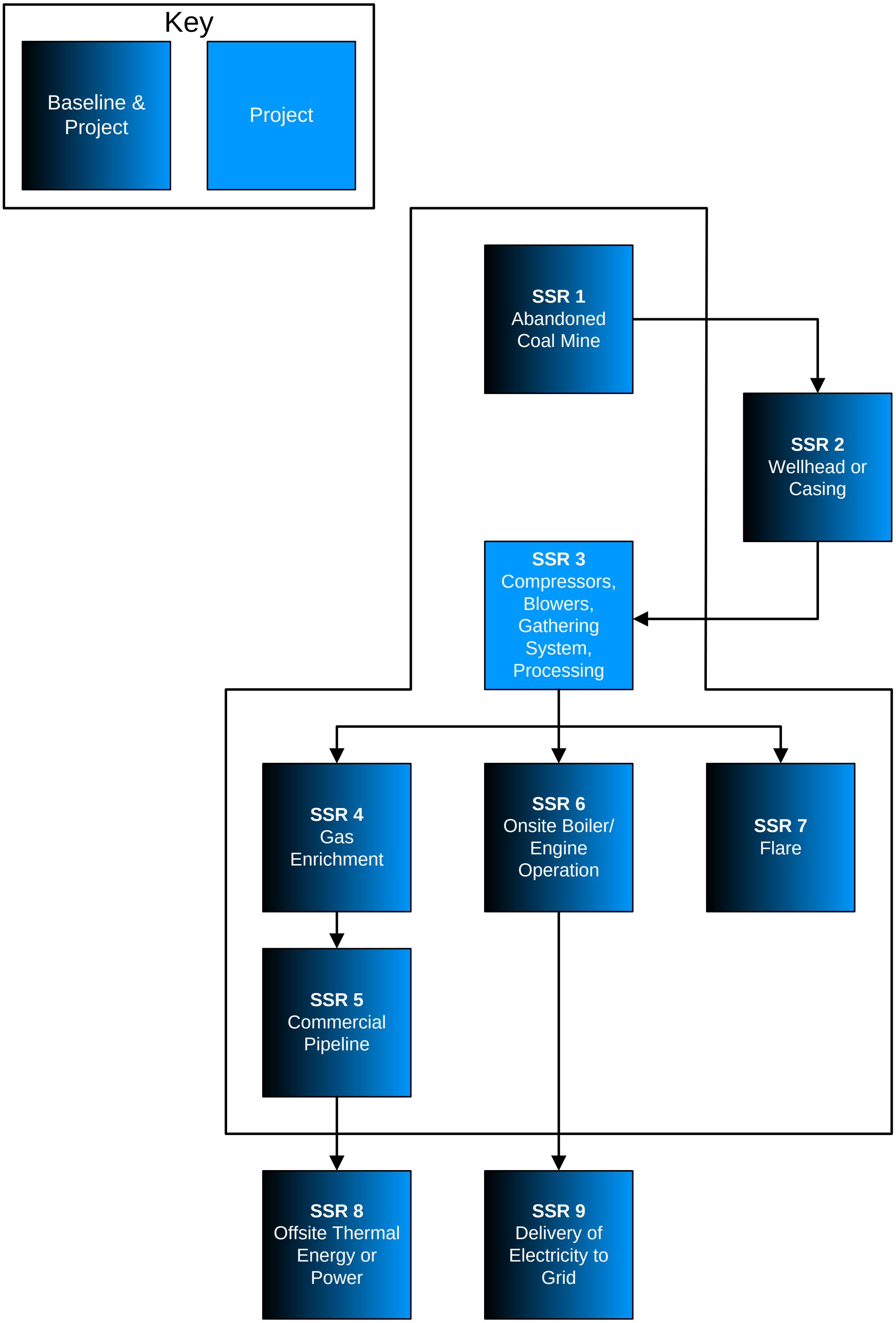

Figure 3.1 General Illustration of the Offset Project Boundary

Table 3.1 Summary of Identified GHG Sources, Sinks, and Reservoirs

SSR	Description	GHG	Relevant to Project Baseline (B) or Offset Project (P)	Included/Excluded
1	Emissions of methane as a result of venting	CH_4	B, P	Included
2	Fugitive emissions resulting from casing or wellhead	CH_4	N/A	Excluded
3	Emissions resulting from energy used by compressors, blowers, gathering systems, processing	CO_2	P	Included
		CH_4		Excluded
		N_2O		Excluded
	Fugitive emissions resulting from energy used by compressors, blowers, and/or gathering systems	CH_4	N/A	Excluded
4	Emission resulting from energy used by gas enrichment system	CO_2	P	Included
		CH_4		Excluded
		N_2O		Excluded
	Fugitive emissions from gas enrichment system	CH_4	N/A	Excluded
5	Emissions from combustion of gas by end user of pipeline	CO_2	B, P	Included
		N_2O		Excluded
	Emissions resulting from the incomplete combustion during end use destruction	CH_4	P	Included
	Emissions from NMHC destruction	CO_2	P	Included if NMHC accounts for more than 1% by volume of extracted coal mine gas
6	Emissions resulting from combustion during on-site electricity generation	CO_2	B, P	Included
		N_2O		Excluded
	Emissions resulting from incomplete combustion during on-site electricity generation	CH_4	P	Included
	Emissions from NMHC destruction	CO_2	P	Included if NMHC accounts for more than 1% by volume of extracted coal mine gas
7	Emissions resulting from combustion during flaring	CO_2	B, P	Included
		N_2O		Excluded
	Emissions resulting from incomplete combustion during flaring	CH_4	P	Included
	Emissions from NMHC destruction	CO_2	P	Included if NMHC accounts for more than 1% by volume

				of extracted coal mine gas
8	Emissions resulting from offsite thermal or power generation	CO_2 CH_4 N_2O	N/A	Excluded
9	Delivery and use of project electricity to grid	CO_2 CH_4 N_2O	N/A	Excluded

4 Quantifying GHG Emission Reductions

In this protocol only methane volumes equal to or less than the baseline emissions are eligible for emission reductions through destruction of the methane. The project can never be credited with more than the baseline emissions for any given year.

The emission reductions (ER_t) by the project activity during a given reporting period t is the difference between the baseline emissions (BE_t) and project emissions (PE_t), as follows:

$$ER_t = BE_t - PE_t \tag{1}$$

Where,

ER_t = Emissions reductions by the project activity during the reporting period (tCO_2e)

BE_t = Baseline emissions during the reporting period (tCO_2e)

PE_t = Project emissions during the reporting period (tCO_2e)

4.1 Quantifying Baseline Emissions

Baseline emissions for an abandoned mine are calculated based on the mine's historical emissions when operating and on dimensionless rate decline curves which were generated for the major coal basins of the United States.

The curve for a given mine is initialized at the date of abandonment and extrapolated through the crediting period. For most mines the project start date of an AMM mitigation project will be several years after the date of abandonment

$$BE_t = BE_{MD,t} + BE_{MR,t} \tag{2}$$

Where,

BE_t = Baseline emissions during the reporting period (tCO_2e)

$BE_{MD,t}$ = Baseline emissions that would have been from destruction of methane during the reporting period (tCO_2e)

$BE_{MR,t}$	=	Baseline emissions from release of methane into the atmosphere avoided by the project activity during the reporting period (tCO_2e)

4.1.1 Calculating Methane Destruction in the Baseline

Methane may be destroyed in the baseline scenario through flaring, flameless oxidation, power generation, heat generation, or as a gas supply to various combustion end uses. Baseline emissions should account for the CO_2 emissions resulting from the destruction of that methane.

$$BE_{MDt} = (CEF_{CH4} + r \times CEF_{NMHC}) \times \sum_i AMM_{BL,i,t} \tag{3}$$

Where,

BE_{MDt}	=	Baseline emissions from destruction of methane in the reporting period (tCO_2e)
i	=	Destruction device (flaring, power generation, heat generation, supply to gas grid to various combustion end uses)
$AMM_{BL,i,t}$	=	AMM that would have been captured, sent to and destroyed by use *i* in the baseline scenario in the reporting period (tCH_4)
CEF_{CH4}	=	Carbon emission factor for combusted methane (2.75 tCO_2e/tCH_4)
CEF_{NMHC}	=	Carbon emission factor for combusted non methane hydrocarbons. This parameter should be obtained through periodical analysis of captured methane ($tCO_2eq/tNMHC$)
r	=	Relative proportion of NMHC compared to methane

With:

$$r = \frac{PC_{NMHC}}{PC_{CH_4}} \tag{4}$$

Where,

PC_{NMHC}	=	NMHC concentration (in mass) of methane in extracted gas, to be measured on wet basis (lb/ft^3)
PC_{CH4}	=	Concentration (in mass) of methane in extracted gas, to be measured on wet basis (lb/ft^3)

4.1.2 Calculating Methane Released into the Atmosphere

Baseline emission must include the methane that would have been emitted to the atmosphere in the absence of the project activity.

$$BE_{MRt} = GWP_{CH4} \times \sum_i \min(AMM_{PJ,i,t}, AMM_{DC,t}) \quad \textbf{(5)}$$

Where:

BE_{MRt}	=	Baseline emissions from release of methane into the atmosphere avoided by the project activity during the reporting period (tCO_2e)
i	=	Use of methane (flaring, power generation, heat generation, supply to gas grid to various combustion end uses)
$AMM_{PJ,i,t}$	=	AMM captured by use i of the project activity in reporting period t (tCH_4)
$AMM_{DC,t}$	=	Emissions of methane from the decline curve of the abandoned mine in reporting period t(tCH_4)
GWP_{CH4}	=	Global warming potential of methane (21 tCO_2e/tCH_4)

On an annual basis, the ex ante projected mass of methane emissions calculated using the decline curve is compared to the mass of methane captured by the project activity. The lesser of these two annual masses will be used to calculate the baseline emissions. Using the minimum of these values is conservative, and ensures that the qualifying emissions are never greater than either the emissions projected using a decline curve or the amount of methane captured by the project activity.

The methane that is still vented or escapes through diffuse emissions in the project scenario is not accounted for in the project emissions or in the baseline emissions, since it is vented in both scenarios.

4.1.2.1 Determining Baseline Emissions

The approach to determine the quantity of methane which would be released to the atmosphere by an abandoned mine in reporting period t is detailed below. The following data parameters are required to estimate the emission rate of an abandoned mine over time:

1. Date of mine closure or decommissioning
2. Methane emissions averaged over the life of the mine in thousand cubic feet of CH_4 per day (Mscf/day) at standard conditions of temperature and pressure
3. Whether the mine has been venting through an open shaft or bore(s) or has been deemed to be sealed

The emissions rate from an abandoned mine through time can be described by a hyperbolic emission rate decline curve. This function is directly related to the physical parameters of the coal mine such as the gassiness of the mine, which is in turn related to the mine size and the gas content of the coal and the permeability of the coal to the flow of gas.

Step 1: Determine the hyperbolic emission rate decline curve coefficients

Obtain hyperbolic decline curve coefficients as published by the U.S. EPA through the Coalbed Methane Outreach Program (CMOP)[1] developed for the U.S. national greenhouse gas inventory[2]. These decline curves are specific to U.S. coal basins as shown in Table 1 and are defined below.

Table 1: Hyperbolic decline coefficients for vented or sealed abandoned underground coal mines

Basin	Variable	Venting	Sealed
Northern Appalachian	b	2.293E+00	2.293E+00
	Di 1/day	3.564E-03	8.740E-05
Illinois	b	2.315E+00	2.315E+00
	Di 1/day	3.659E-03	8.669E-05
Central Appalachian	b	2.329E+00	2.329E+00
	Di 1/day	3.735E-03	8.652E-05
Black Warrior	b	2.300E+00	2.300E+00
	Di 1/day	3.601E-03	8.732E-05
Western States	b	2.342E+00	2.342E+00
	Di 1/day	3.803E-03	8.627E-05

Step 2: Calculate ex ante projection of emissions of methane from abandoned mines using the coefficients determined in Step 1

The ex ante projection of emissions of methane from venting and sealed abandoned mines can be calculated using the following equation:

$$AMM_{DC,t} = V_{AMM,to} * D_{CH4,corr} * S * (1 + b * D_i * t)^{\left(\frac{-1}{b}\right)} \quad (6)$$

Where,

$AMM_{DC,t}$ = Emissions of methane from the decline curve of the abandoned mine in reporting period t measured (tCH4)

$V_{AMM,to}$ = Average emission rate of methane over the life of the mine closure at time (to) in thousand standard cubic feet per day (Mscf/d)

$D_{CH4,corr}$ = Density of methane at standard conditions of temperature and pressure (0.0424 lb/scf)

S = The default effective degree of sealing is 80% sealed at the time of abandonment. Therefore,

[1] http://www.epa.gov/cmop/docs/abandoned_mine_variables_by_basin.pdf
[2] http://www.epa.gov/cmop/docs/amm_final_report.pdf

- Venting mines, S = 1.0
- Sealed mines, S = 0.2

b = Dimensionless hyperbolic exponent. Use the exponent for vented or sealed mines for relevant coal basin as found in Table 1

D_i = Initial decline rate, (1/day). Use the exponent for vented or sealed mines for relevant coal basin as found in Table 1

t = The time elapsed from the date of mine closure to midpoint of the current reporting period t (days)

4.2 Quantifying Project Emissions

Project emissions are defined by the following equation:

$$PE_t = PE_{ME} + PE_{MD} + PE_{UM} \quad \textbf{(6)}$$

Where,

PE_t = Project emissions in reporting period t (tCO_2e)

PE_{ME} = Project emissions from energy use to capture and use methane (tCO_2e)

PE_{MD} = Project emissions from methane destroyed (tCO_2e)

PE_{UM} = Project emissions from un-combusted methane (tCO_2e)

4.2.1 Project Emissions from Energy Required for Methane Collection, Transport, and Combustion

Included in the GHG Assessment Boundary are carbon dioxide emissions resulting from fossil fuel combustion and/or use of grid-delivered electricity for on-site equipment that is used for:

- Compressors, blowers and/or AMM gathering systems
- Transporting AMM to on-site combustion
- Transporting AMM to a pipeline
- Transporting AMM to boilers/engines for power generation
- Transporting AMM to a flare

$$PE_{ME} = (CONS_{ELEC,PJ} \times CEF_{ELEC}) + \frac{(CONS_{HEAT,PJ} \times CEF_{HEAT} + CONS_{FossFuel,PJ} \times CEF_{FossFuel})}{2204.62} \quad \textbf{(7)}$$

Where,

PE_{ME}	=	Project emissions from energy use to capture and use or destroy methane during the reporting period (tCO_2e)
$CONS_{ELEC,PJ}$	=	Additional electricity consumption for capture and use or destruction of methane during the reporting period, if any (MWh)
CEF_{ELEC}	=	Carbon emissions factor of electricity used by coal mine (tCO_2/MWh)
$CONS_{HEAT,PJ}$	=	Additional heat consumption for capture and use or destruction of methane during the reporting period, if any (volume)
CEF_{HEAT}	=	Carbon emissions factor of heat used by coal mine during the reporting period (lb CO_2e/volume); see Appendix A
$CONS_{FossFuel,PJ}$	=	Additional fossil fuel consumption for capture and use or destruction of methane during the reporting period, if any (volume)
$CEF_{FossFuel}$	=	Carbon emissions factor of fossil fuel used by coal mine (lb CO_2/volume)
2204.62	=	Conversion of pounds to metric tons

4.2.2 Project Emissions from Destruction of Captured Methane

When AMM is sent to a pipeline for eventual combustion, burned in a flare, or heat or power plant, carbon dioxide emissions are released and must be included in the calculations. In addition, if non-methane hydrocarbons (NMHC) comprise more than 1% of the volume of extracted AMM, carbon dioxide emissions from combustion of NMHC must also be accounted for.

$$PE_{MD} = MD_i + (CEF_{CH_4} + r \times CEF_{NMHC}) \qquad \textbf{(8)}$$

With:

$$r = \frac{PC_{NMHC}}{PC_{CH_4}}$$

PE_{MD}	=	Project emissions from methane destroyed during the reporting period (tCO_2e)
MD_i	=	Methane destroyed by all qualifying and non-qualifying devices during the reporting period (tCH_4)
CEF_{CH4}	=	Carbon emission factor for combusted methane (2.75 tCO_2/tCH_4)
CEF_{NMHC}	=	Carbon emission factor for combusted non methane hydrocarbons (the concentration varies and, therefore, to be obtained through periodical analysis of captured methane) (tCO_2/tNMHC)
r	=	Relative proportion of NMHC compared to methane
PC_{NMHC}	=	NMHC concentration (in mass) of methane in extracted gas, to be measured on wet basis (lb/scf)
PC_{CH4}	=	Concentration (in mass) of methane in extracted gas, measured on wet basis (lb/scf)

$$MD_i = \sum_i MM_i \times Eff_i \quad \textbf{(9)}$$

Where,

MD_i	=	Methane destroyed by all qualifying and non-qualifying devices during the reporting period (tCH_4)
MM_i	=	Methane measured sent to use i (tCH_4)
Eff_i	=	Efficiency of methane destruction for device i (%)

Apply the following equation only if the AMM flow metering equipment does not internally correct for temperature and pressure.

$$MD_{adjusted,i} = MM_{unadjusted,i} \times \frac{520}{T} \times \frac{P}{1} \quad \textbf{(10)}$$

Where,

$MD_{adjusted,i}$	=	Adjusted volume of AMM collected for the given time interval at utilization type i, adjusted to 60° F and 1 atm (scf/unit time)
$MM_{unadjusted,i}$	=	Unadjusted volume of AMM collected for the given time interval at utilization type i (scf/unit time)
T	=	Measured temperature of the AMM for the given time period, °R = °F + 460 (°R)
P	=	Measured pressure of the AMM for the given time interval (atm)

4.2.3 Project Emissions from Uncombusted Methane

Not all of the methane sent to the flare, pipeline, or to generate heat and power will be combusted; a small amount will escape to the atmosphere. These emissions are calculated using the equation below.

$$PE_{UM} = GWP_{CH_4} \times \sum_i MM_i \times (1 - Eff_i) \quad \textbf{(11)}$$

PE_{UM}	=	Project emissions from uncombusted methane during the reporting period (tCO_2e)
GWP_{CH4}	=	Global warming potential of methane (21) (tCO_2e/tCH_4)
i	=	The set of qualifying and non-qualifying destruction devices
MM_i	=	Methane measured sent to use i (tCH_4)
Eff_i	=	Efficiency of methane destruction for device i (%)

5 Offset Project Documentation and Monitoring Requirements

Project developers are responsible for monitoring the performance of the project and ensuring that the operation of AMM destruction devices is consistent with the manufacturer's recommendations for each piece of equipment.

5.1 Monitoring Requirements

Methane destruction devices must be monitored with measurement equipment that directly meters:

- The flow of gas delivered to each destruction device (unless otherwise allowed by Section 5.1.1), measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure
- The fraction of methane in the gas from measured continuously and recorded every 15 minutes and averaged at least daily

All flow data collected must be corrected for temperature and pressure at standard conditions (60°F and 1 atm). Equation 10 must be applied if flow metering equipment does not make this correction automatically. Depending on the methane analyzer technology used, methane concentration data may or may not need to be corrected for temperature and pressure. If the methane analyzer technology used requires adjustment for temperature and pressure, then concentration data must also be corrected to 60°F and 1 atm.

NMHC content of the gas shall be determined on an annual basis by a full gas analysis using a gas chromatograph at an ISO 17025 accredited lab or a lab that has been certified by an accreditation body conformant with ISO 17025 to perform test methods appropriate for NMHC content analysis. Separate gas samples shall be collected by a third-party technician prior to each destruction device within the project definition.

Operational activity of the AMM systems and the destruction devices shall be monitored and documented at least hourly to ensure actual methane destruction. GHG reductions will not be accounted for during periods in which the destruction device is not operational. For flares, operation is defined as thermocouple readings above 500°F. For all other destruction devices, the means of demonstration shall be determined by the project developer and subject to verifier review.

5.1.1 Arrangement of Gas Metering Equipment

The flow of gas to each destruction device must be monitored separately for each destruction device, except under certain conditions. Specifically, if all destruction devices are of identical efficiency and verified to be operational throughout the reporting period, a single flow meter may be used to monitor gas flow to all destruction devices. Otherwise, the destruction efficiency of the least efficient destruction device shall be used as the destruction efficiency for all destruction devices monitored by this meter.

If a project using a single meter to monitor gas flow to multiple destruction devices has any periods when not all destruction devices downstream of a single flow meter are operational, methane destruction from the set of downstream devices during these periods will only be eligible provided that the verifier can confirm all of the following requirements and conditions are met:

a. The destruction efficiency of the least efficient downstream destruction device in operation shall be used as the destruction efficiency for all destruction devices downstream of the single meter; and
b. All devices are either equipped with valves on the input gas line that close automatically if the device becomes non-operational (requiring no manual intervention), or designed in such a manner that it is physically impossible for gas to pass through while the device is non-operational; and
c. For any period during which one or more downstream destruction devices are not operational, it must be documented that the remaining operational devices have the capacity to destroy the maximum gas flow recorded during the period.

5.2 Instrument QA/QC

Monitoring instruments shall be inspected, cleaned, and calibrated according to the following schedule.

All gas flow meters and continuous methane analyzers must be:

- Cleaned and inspected on a regular basis, as specified in the project's monitoring plan, with the activities and results documented by site personnel. Cleaning and inspection frequency must, at a minimum, follow the manufacturer's recommendations.
- Field checked for calibration accuracy by an appropriately trained individual or a third party technician with the percent drift documented, using either a portable instrument or manufacturer specified guidance, at the end of – but no more than two months prior to or after – the end date of the reporting period. If a portable calibration instrument is used for field checks, the portable instrument shall be maintained and calibrated per the manufacturer's specifications, and calibrated at least annually by the manufacturer or at an ISO 17025 accredited laboratory. For portable methane analyzers, the portable instrument must be field calibrated to a known sample gas prior to each use.
- Calibrated by the manufacturer or a third-party calibration service at the frequency recommended by the manufacturer. If the manufacturer does not specify a recommended calibration schedule, then no calibrations are required, unless a field check reveals a difference of +/- 5% or more.
    - Flow meter calibrations shall be documented to show that the meter was calibrated to a range of flow rates corresponding to the flow rates expected at the mine.
    - Methane analyzer calibrations shall be documented to show that the calibration was carried out to the range of conditions (temperature and pressure) corresponding to the range of conditions as measured at the mine.

If the field check on a piece of equipment reveals a difference of +/- 5% or more between the value measured by the portable calibration instrument and the value measured by the monitoring instrument, calibration by the manufacturer or a third-party calibration service is required for that piece of equipment.

For the interval between the last successful field check/calibration and any field check/calibration event revealing accuracy outside the +/- 5% threshold, all data from that meter or analyzer must be scaled according to the following procedure based on the results of the calibration report from the manufacturer or third-party service provider. These adjustments must be made for the entire period from the last successful field check/calibration until such time as the meter is properly calibrated and in place.

- For calibrations that indicate an underestimation of emission reductions, the metered values must be used without correction.
- For calibrations that indicate an overestimation of emission reductions, the metered values must be adjusted based on the greatest calibration drift recorded at the time of calibration.

For example, if a project conducts field checks quarterly during a year-long reporting period, then only three months of data will be subject at any one time to the penalties above. However, if the project developer feels confident that the meter does not require field checks or calibration more than annually, then failed events will accordingly require the adjustments above to be applied to the entire year's data. Further, frequent calibration may minimize the total accrued drift (by zeroing out any error identified), and result in smaller overall deductions.

In order to provide flexibility at verification, data monitored up to two months after a field check may be verified. As such, the end date of the reporting period must be no more than two months after the latest successful field check. A field check conducted up to two months after the end date of a reporting period is also acceptable to confirm the accuracy of the equipment during the reporting period.

Project developers have the option to use either the default methane destruction efficiencies provided in the protocol, or the site-specific methane destruction efficiencies as provided by a state- or local agency-accredited source test service provider, for any of the destruction devices used in the project, performed on an annual basis. Device-specific source testing shall include at least three test runs, with the accepted final value being one standard deviation below the mean of the measured efficiencies.

5.3 Missing Data

In situations where the data from the flow rate or methane concentration monitoring equipment is missing, the project developer shall apply the data substitution methodology provided in Appendix B. If for any reason the destruction device monitoring equipment is inoperable (for example, the thermocouple on the flare), then no emission reductions can be credited for the period of inoperability.

5.4 Monitoring Parameters

Prescribed monitoring parameters necessary to calculate baseline and project emissions are provided in Table 5.1.

Table 5.1 Abandoned Mine Methane Project Monitoring Parameters

Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference (r) Operating records (o)	Measurement Frequency
$AMM_{BL,i,t}$	AMM that would have been captured, sent to and destroyed by use *i* in the baseline scenario in the reporting period	tCH_4	c,m	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place
CEF_{NMHC}	Carbon emission factor for combusted non methane hydrocarbons. This parameter should be obtained through periodical analysis of captured methane	$tCO_2eq/tNMHC$	m	Annually
PC_{NMHC}	NMHC concentration (in mass) of methane in extracted gas, to be measured on wet basis	lb/scf	m	Annually
PC_{CH4}	Concentration (in mass) of methane in extracted gas, to be measured on wet basis	lb/scf	m	Continuous
$AMM_{PJ,i,t}$	AMM captured by use i of the project activity in reporting period t	tCH_4	c,m	Every reporting period
$AMM_{DC,t}$	Emissions of methane from the decline curve of the abandoned mine in reporting period t	tCH_4	c	Every reporting period
GWP_{CH4}	Global warming of methane	tCO_2e/tCH_4	r	21
$V_{AMM,to}$	Emissions of methane prior to mine closure at time (t_o)	Mscf/d	m,o	At the beginning of the project
S	Default effective degree of sealing is 80% sealed at the time of abandonment	%	r	At the beginning of the project
b	Dimensionless hyperbolic	N/A	r	At the beginning of

	exponent			the project
D_i	Initial decline rate	N/A	r	At the beginning of the project
$CONS_{ELEC,PJ}$	Additional electricity consumption for capture and use or destruction of methane, if any	MWh	o	Every reporting period
CEF_{ELEC}	Carbon emissions factor of electricity used by coal mine	tCO_2/MWh	r	Every reporting period
$CONS_{HEAT,PJ}$	Additional heat consumption for capture and use or destruction of methane, if any	volume	o	Every reporting period
CEF_{HEAT}	Carbon emissions factor of heat used by coal mine	lb CO_2e/volume	c	Every reporting period
$CONS_{FossFuel,PJ}$	Additional fossil fuel consumption for capture and use or destruction of methane, if any	volume	o	Every reporting period
$CEF_{FossFuel}$	Carbon emissions factor of fossil fuel used by coal mine	lb CO_2/volume	R	Every reporting period
MD_i	Methane destroyed by all qualifying and non-qualifying devices	tCH_4	c	Every reporting period
MM_i	Methane measured sent to use i	tCH_4	m	Continuous
Eff_i	Efficiency of methane destruction for device i	%	m,r	Annually
$MD_{adjusted,i}$	Adjusted volume of AMM collected for the given time interval at utilization type i, adjusted to 60° F and 1 atm	scf/unit time	c	Every reporting period
$MM_{unadjusted,i}$	Unadjusted volume of AMM collected for the given time interval at utilization type i	scf/unit time	c	Every reporting period
T	Measured temperature of the AMM for the given time period, °R = °F + 460	°R	m	Continuously
P	Measured pressure of the AMM for the given time interval	atm	m	Continuously

6 Reporting Parameters

This section provides requirements and guidance on reporting rules and procedures.

6.1 Document Retention

System information to be retained shall include, but is not limited to:

- All data inputs for the calculation of GHG reductions, including all required sampled data
- Copies of operating permits, air, water, and land use permits;
- Copies of the final mine plan that has been submitted MSHA or to the relevant state government authority upon abandonment
- Flow meter information (model number, serial number, manufacturer's calibration procedures)
- Methane monitor information (model number, serial number, calibration procedures)
- Destruction device monitor information (model number, serial number, calibration procedures)
- Field checks and calibration results for all meters
- Corrective measures taken if meter does not meet performance specifications
- Destruction device monitoring data (for each destruction device)
- Project flow and methane concentration data
- Emission reduction calculations
- Verification records, results and reports from each verification
- All maintenance records relevant to the project monitoring equipment and destruction devices.

Appendix A Emission Factors

PLACEHOLDER - [eGRID Table]

PLACEHOLDER - [Destruction Efficiencies]

<u>Calculating Heat Generation Emission Factor</u>

$$CEF_{HEAT,t} = \frac{EF_{CO_2,i}}{Eff_{heat}} \times \frac{44}{12} \qquad \textbf{(12)}$$

Where,

$CEF_{HEAT,t}$	=	Emission factor for heat generation (lb CO_2/volume)
$EF_{CO_2,i}$	=	CO_2 emission factor of fuel used in heat generation (lb C/volume)
Eff_{heat}	=	Boiler efficiency of the heat generation; either measured efficiency, manufacturer nameplate data, or 100% (%)
$44/12$	=	Carbon to carbon dioxide conversion factor

Appendix B Data Substitution Guidelines

This appendix provides guidance on calculating emission reductions when data integrity has been compromised due to missing data points. No data substitution is permissible for equipment such as thermocouples which monitor the proper functioning of destruction devices. Rather, the methodologies presented below are to be used only for the methane concentration and flow metering parameters, including temperature and pressure data.

The following data substitution methodology may be used only for flow and methane concentration data gaps that are discrete, limited, non-chronic, and due to unforeseen circumstances. Data substitution can only be applied to methane concentration or flow readings, but not both simultaneously. If data is missing for both parameters, no reductions can be credited. The methodology may also be used for missing temperature and pressure data (which is used to adjust flow rate). However, the methodology must be applied to both parameters simultaneously, regardless of if data is available for one or the other. Thus, if either temperature or pressure data is missing, the following methodology to substitute data for both parameters over the same time interval must be used.

Further, substitution may only occur when two other monitored parameters corroborate proper functioning of the destruction device and system operation within normal ranges. These two parameters must be demonstrated as follows:

1. Proper functioning can be evidenced by thermocouple readings for flares, energy output for engines, etc.
2. For methane concentration substitution, flow rates during the data gap must be consistent with normal operation.
3. For flow substitution, methane concentration rates during the data gap must be consistent with normal operations.

If corroborating parameters fail to demonstrate any of these requirements, no substitution may be employed. If the requirements above can be met, the following substitution methodology maybe applied:

Duration of Missing Data	Substitution Methodology
Less than six hours	Use the average of the four hours of normal operations immediately before and following the outage
Six to 24 hours	Use the 90% lower or upper confidence limit of the 24 hours of normal operations prior to and after the outage, whichever results in greater conservativeness
One to seven days	Use the 95% lower or upper confidence limit of the 72 hours of normal operations prior to and after the outage, whichever results in greater conservativeness
Greater than one week	No data may be substituted and no credits may be generated

The lower confidence limit should be used for both methane concentration and flow readings, as this will provide the greatest conservativeness.