**DRAFT- Approved baseline methodology AM00XX**

**"Natural gas-based package cogeneration"**

**Source**

This methodology is based on the MGM natural gas-based package cogeneration project, Chile, whose baseline study, monitoring and verification plan and project design document were prepared by MGM International. For more information regarding the proposal and its consideration by the Executive Board please refer to case NM0018: "MGM baseline methodology Natural Gas-Based Package cogeneration Project" on http://cdm.unfccc.int/methodologies/approved

**Selected approach from paragraph 48 of the CDM modalities and procedures**

"Existing actual or historical emissions as applicable."

**Applicability**

This methodology is applicable to natural gas-based cogeneration projects under the following conditions:

- The cogeneration system is a third party cogeneration systems, i.e. not own or operated by the consuming facility that receives the project heat and electricity;
- The cogeneration system provides all or a part of the electricity and or heat demand of the consuming facility;
- No excess electricity is supplied to the power grid and no excess heat from the cogeneration system is provided to another user.

**Project activity**

The project activity encompasses the installation of a package cogeneration system whose input is natural gas from the gas pipeline, and whose outputs are electricity and heat supplied to an industry with demand for heat and electricity. The owner and operator of the cogeneration system is different from that of the industry that purchases heat and electricity from the system.

**Leakage**

The principal sources of "leakage" in the sense of emissions of GHG emissions outside the project boundary and attributable to the CDM project are the emission of methane from natural gas production and pipeline leakage, associated with gas consumption of cogeneration system.

**Baseline**

Baseline emissions are those emissions that those associated with the production of heat and electricity that are offset by the output of the cogeneration system. Baseline emissions comprise five components:

a) **$CO_2$ from combustion.** $CO_2$ emissions corresponding to the combustion of natural gas that would have been used if the cogeneration system did not provide heat to the factory.
b) **$CH_4$ from combustion.** $CH_4$ emissions corresponding to the combustion of natural gas that would have been used if the cogeneration system did not provide heat to the factory.
c) **$N_2O$ from combustion.** $N_2O$ emissions corresponding to the combustion of natural gas that would have been used if the cogeneration system did not provide heat to the factory.

d) **$CH_4$ leaks.** $CH_4$ emissions from natural gas production and leaks in the transport and distribution pipeline supplying the factory and leaks in the gas distribution piping within the factory, associated with the natural gas consumption identified in item (a) above.

e) **$CO_2$ from electricity generation.** $CO_2$ emissions associated with the electricity that would have to be purchased from the power grid if the cogeneration system did not provide electricity to the factory.

The baseline emissions for the first four items are proportional to the natural gas consumption in the factory that is offset by heat supplied by the cogeneration system. Each can be represented as the product of an emissions factor and an energy consumption, which depends on the heat output of the cogeneration system.

The consumption of natural gas avoided in the baseline for the supply of heat is determined as follows:

**Annual baseline natural gas energy consumption for heat supply, *$ABEC_{NG}$* (GJ/year)**:

$$ABEC_{NG} = \frac{CAHO}{e_b} \qquad \textbf{(3.1)}$$

where CAHO = annual heat output from cogeneration system (GJ/year), and
$e_b$ = industrial boiler efficiency (fraction, lower heating value basis).

This is estimated on the basis of the heat output rate of the cogeneration system (*CHOR*) and an estimate of annual operating hours (*AOH*) of the cogeneration system. The formula is described below:

**Annual baseline natural gas energy consumption for heat supply, *$ABEC_{NG}$* (GJ/year):**

$$ABEC_{NG}\ (GJ/year) = \frac{CHOR \cdot AOH}{e_b} \qquad \textbf{(3.2)}$$

where *CHOR* = cogeneration system heat output rate (GJ/h),
*AOH* = Annual operating hours (h/year), and
$e_b$ = boiler efficiency (fraction, lower heating value basis)

In order to be conservative, a high value of $e_b$ is chosen. The methodology proposes a default value of 0.90.

The value of ***CHOR*** may be determined from the specifications of the cogeneration system. A value of ***AOH*** should be determined from an engineering study of the proposed cogeneration system.
Once the boiler energy consumption has been quantified, the four GHG emissions components (a to d, above) can be determined, as indicated below.

**a) Baseline $CO_2$ emissions from natural gas combustion for heat supply to plant**

A value of $\boldsymbol{EF_{NG}}$ needs to be estimated from the following data sources. The numbers indicate a hierarchy in data to be used, with #1 being the best. If #1 data are not available, #2 data should be chosen. If these are not available,#3 data should be chosen.

1. National GHG inventory
2. IPCC, fuel type and technology specific
3. IPCC, near fuel type and technology

**b) Baseline methane emissions from natural gas combustion for heat supply to plant**

**Baseline methane emissions from natural gas combustion for heat supply, $BE_{met\ comb}$ (tonne $CH_4$/year)**:

$$BE_{met\ comb}\,(tonne\ CH_4\,/\,year) = \frac{ABEC_{NG} \cdot MEF}{10^6} \tag{3.4}$$

where $ABEC_{NG}$ = annual baseline natural gas energy consumption for heat supply (GJ/year), and
$MEF$ = methane emission factor for natural gas combustion (kg $CH_4$/TJ, *lower* heating value basis)

**In units of carbon dioxide equivalent, $BE_{equiv\ met\ comb}$ (tonne $CO_2$ eq/year)**

$$BE_{equiv\ met\ comb}\,(tonne\ CO_2 - equiv\,/\,year) = BE_{met\ comb} \cdot GWP\,(CH_4) \tag{3.5}$$

where GWP ($CH_4$) = global warming potential of methane = 21

The value of ***MEF*** needs to be estimated from the following data sources. The numbers indicate a hierarchy in data to be used, with #1 being the best. If #1 data are not available, #2 data should be chosen.

1. IPCC, fuel type and technology specific
2. IPCC, near fuel type and technology

**c) Baseline nitrous oxide emissions from natural gas combustion for heat supply to plant**

**Baseline nitrous oxide emissions from natural gas combustion for heat supply, $BE_{N_2O\ comb}$ (tonne $N_2O$/year)**:

$$BE_{N_2O\ comb}\,(tonne\ CH_4\,/\,year) = \frac{ABEC_{NG} \cdot NEF}{10^6} \tag{3.6}$$

where $ABEC_{NG}$ = annual baseline natural gas energy consumption for heat supply (GJ/year), and
$NEF$ = nitrous oxide emission factor for natural gas combustion (kg $N_2O$/TJ, *lower* heating value basis)

**In units of carbon dioxide equivalent, $BE_{equiv\ N_2O\ comb}$ (tonne $CO_2$ equiv/year)**

$$BE_{equiv\ N_2O\ comb}\,(tonne\ CO_2 - equiv\,/\,year) = BE_{N_2O\ comb} \cdot GWP\,(N_2O) \tag{3.7}$$

where *GWP ($N_2O$)* = global warming potential of nitrous oxide = 310

The value of NEF needs to be estimated the following data sources. The numbers indicate a hierarchy in data to be used, with #1 being the best. If #1 data are not available, #2 data should be chosen.

1. IPCC, fuel type and technology specific
2. IPCC, near fuel type and technology

**d) Baseline methane emissions from natural gas production and pipeline leaks in the transport and distribution**

**Baseline methane emissions from natural gas production and leakage in transport and distribution, corresponding to heat supply,** $BE_{th\ fug}$ **(tonne $CH_4$/year)**:

$$BE_{th\ fug}\,(tonne\ CH_4\,/\,year) = \frac{ABEC_{NG}\cdot MLR}{10^3} \qquad \textbf{(3.8)}$$

where MLR = methane leakage rate in natural gas production, transport and distribution leakage, including leaks at the industrial site (kg $CH_4$ /GJ natural gas energy consumption, lower heating value basis).

$ABEC_{NG}$ = annual baseline natural gas energy consumption for heat supply (GJ/year)

**In units of carbon dioxide equivalent emissions,** $BE_{th\ equiv\ fug}$ **(tonne $CO_2$ equiv/year):**

$$BE_{th\ equiv\ fug}\,(tonne\ CO_2 - equiv\,/\,year) = BE_{th\ fug}\cdot GWP\,(CH_4) \qquad \textbf{(3.9)}$$

where $GWP\ (CH_4)$ is defined as before = 21

The value of *MLR* needs to be estimated from the following data sources. The numbers indicate a hierarchy in data to be used, with #1 being the best. If #1 data are not available, #2 data should be chosen.

1. National estimates (if available)
2. IPCC estimates of fugitive emissions from oil and natural gas activities.

**e) Baseline emissions of $CO_2$ from electricity supply to industrial plant, that is offset by electricity supplied from cogeneration system**

The final item of GHG emissions in the baseline arises from *electricity*, corresponding to the emissions avoided at the power plants supplying the public grid, including transmission and distribution losses. The relevant formula is described below:

**Baseline carbon dioxide emissions for electricity supplied,** $BE_{elec}$ **(tonne $CO_2$/year)**:

$$BE_{elec}\,(tonne\ CO_2\,/\,year) = \frac{CEO\cdot BEF_{elec}}{10^3} \qquad \textbf{(3.10)}$$

where *CEO* = cogeneration electricity output (MWh/year), and

$BEF_{elec}$ = baseline $CO_2$ emissions factor for electricity from public supply (kg $CO_2$/MWh)

The actual baseline emissions are determined by monitoring cogeneration electricity output (*CEO*) and calculating $BE_{elec}$. For an *a priori* estimation of the baseline $CO_2$ emissions for electricity supply to the plant, *CEO* is determined by the cogeneration electric power output (*CPO*) and annual operating hours (*AOH*), in a manner similar to Eq. (3.2) for heat output, and is described below.

**Annual electricity generation from the cogeneration system,** *CEO* **(MWh/year)**:

$$CEO\ (MWh\ /\ year) = CPO \cdot AOH \qquad \textbf{(3.11)}$$

*where* *CPO* = cogeneration system net power output capacity ($MW_e$), and
*AOH* = annual operating hours of cogeneration system (h/year)

To estimate $BEF_{elec}$, the $CO_2$ emission factor for electricity supply, users of this methodology shall refer to the "Consolidated Baseline Methodology for Zero-emissions Grid-Connected Electricity Generation from Renewable Sources" where different ways of determining $CO_2$ emission factors for electricity supply from the grid are provided, or to the "Simplified Methodology for Small-scale CDM Project activities" (in case electricity displaced is less than or equal to 15 MW equivalent).

**Total baseline emissions** are given by the sum of the components analyzed above:

$$BE_{total} = BE_{th} + BE_{equiv\ met\ comb} + BE_{equiv\ N_2O\ comb} + BE_{th\ equiv\ fug} + BE_{elec} \qquad \textbf{(3.15)}$$

**Emission Reductions**

Emission reductions are calculated as the difference between baseline and project emissions, taking into account any adjustments for leakage: Project emissions are those associated with natural gas consumption by the cogeneration system, including $CO_2$, $CH_4$ and $N_2O$ emissions from natural gas combustion and $CH_4$ emissions from natural gas production and pipeline leakage, associated with the gas consumption of the cogeneration system.

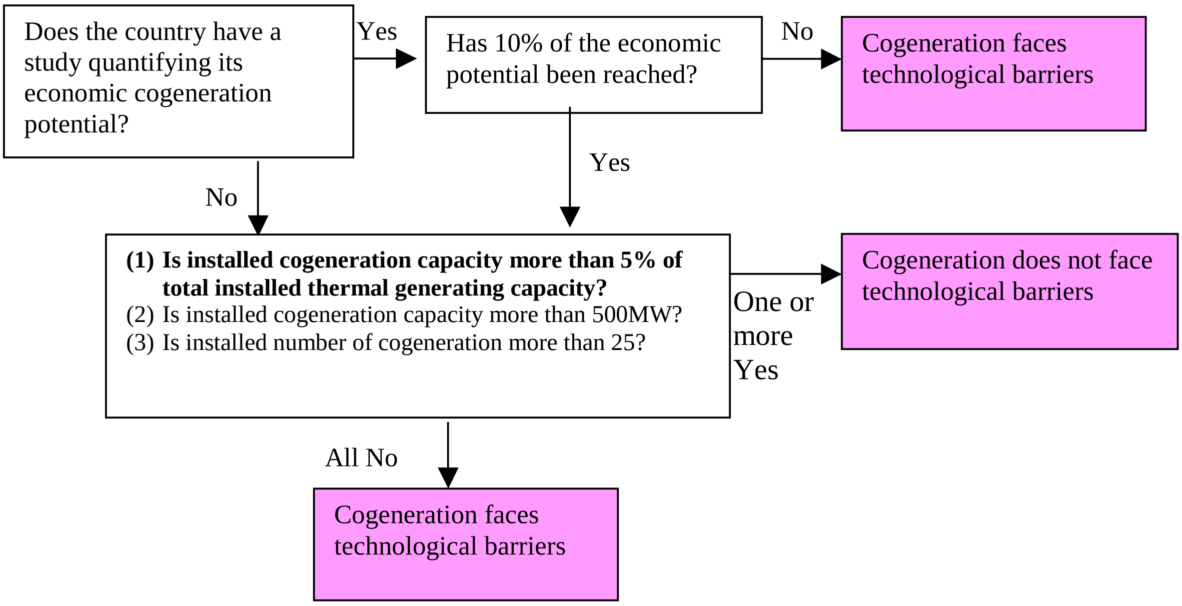
**Additionality**

First likely alternative baseline scenarios are described:
1. Industrial plant continues to operate with equipment replacement as needed with no change in equipment efficiency (The frozen-efficiency scenario).
2. Industrial plant continues to operate with improved efficiency new equipment at the time of equipment replacement.
3. The efficiency of boiler(s) is upgraded immediately.
4. The heat and or electricity demand of the industrial plant is reduced through improvements in end-use efficiency.
5. Installation of a cogeneration system owned by the industrial plant.
6. Installation of a package cogeneration system owned by a company other than the industrial plant (The proposed project).

Three additionality tests are applied. The first two tests are applicable to *any* cogeneration ownership scenario. The third test is specific to the "package cogeneration" case where the cogeneration system is owned by a party other than the industry using the heat and electricity from the system.

1. Are there technological barriers to cogeneration in the country?

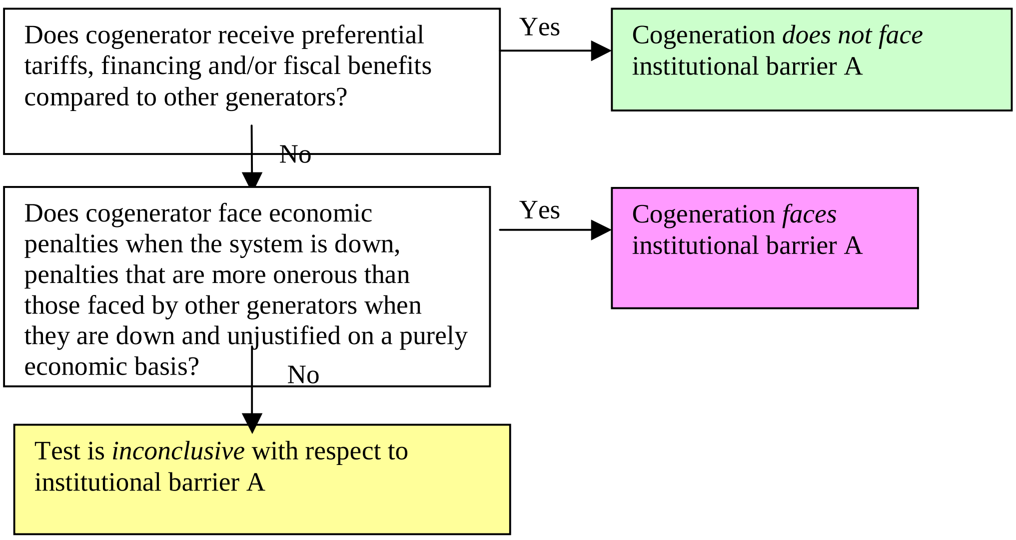
Additionality test 1 is applied by following the flow chart below. A low market share of cogeneration means that there is insufficient infrastructure to support installation and maintenance of such systems, acting as a technological barrier.




2.A Institutional barrier A: Are there institutional barriers to cogeneration in general?

Additionality test 2A is applied by following the flow chart below. It should be noted that even if preferential tariffs or other incentives do exist, they may not be sufficient to promote cogeneration.

A serious barrier may be present, especially in deregulated power systems. All electricity users may have to pay the maximum demand charge for the whole year. Thus, when the cogeneration system is not operating (due to routine maintenance or forced outage), the user of electricity would have to purchase the electricity from the power grid. While this period may be small, the purchase may involve paying for the power demand (kW) for the whole year. This is a significant penalty for users of cogeneration systems.

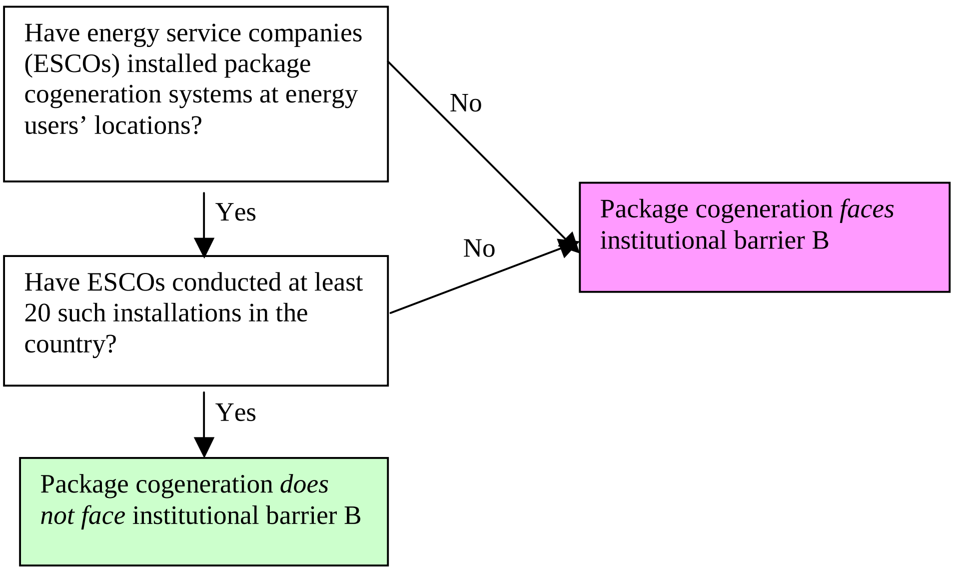


If institutional barriers are not present, but there are no specific incentives to cogeneration, then the test indicated is inconclusive with respect to institutional barrier A. Other barriers (such as technological barrier or institutional barrier B) will need to be considered to determine additionality.

2B. Institutional barrier B: Are there institutional barriers to the "package cogeneration" operational context? In other words, is there enough experience in which one company installs a cogeneration system at the location of a separate energy user?

The traditional practice is for an industrial user to meet their electricity and natural gas demand by purchases from power and gas companies respectively. In a packaged cogeneration system, the institutional arrangement is very different. In this case, the project developer invests in and installs the cogeneration system at the industrial user site, and provides electricity and *heat* to that user. This institutional arrangement requires project developer to have special management resources and organizational capacity, and for the industrial energy user to accept this arrangement. Where such experience is lacking, promoting the new arrangement involves a significant institutional barrier.

Additionality test 2B is applied by following the flow chart below.




If the above additionality tests determine that a package cogeneration system is additional with respect to scenarios where no cogeneration system, scenarios 1 to 4 remain as baseline options. The selection cannot be made without a substantial analysis. Therefore, a conservative approach is taken by assuming a high value for $e_b$ in Eq. 3.2 to calculate the baseline emissions. This assumption implies reduced natural gas consumption in the baseline, and therefore reduced emission reductions compared to option 1-3. Option 4 is discounted for by determining the baseline ex-post on the basis of actual heat and electricity of the industrial plant.

**DRAFT- Approved monitoring methodology AM00XX**

**"Natural gas-based package cogeneration"**

**Source**

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**Applicability**

This methodology is applicable to natural gas-based cogeneration projects under the following conditions:

- The cogeneration system is a third party cogeneration systems, i.e. not own or operated by the consuming facility that receives the project heat and electricity;
- The cogeneration system provides all or a part of the electricity and or heat demand of the consuming facility;
- No excess electricity is supplied to the power grid and no excess heat from the cogeneration system is provided to another user.

**Monitoring Methodology**

The monitoring methodology involves monitoring of the following:

- The natural gas consumption at the cogeneration system;
- Heat production at the cogeneration system;
- Electricity production at the cogeneration system.

Project emissions correspond to natural gas combustion by the cogeneration system, and includes the same four components as in the baseline ($CO_2$, $CH_4$ and $N_2O$ emissions from combustion) and $CH_4$ emissions from natural gas production and leaks in the transport and distribution pipeline supplying the factory and leaks in the gas distribution piping within the factory, associated with the natural gas consumption. Each of these is proportional to the natural gas consumption in the cogeneration system, which is monitored. Emissions are then calculated as follows:

**a) $CO_2$ emissions from natural gas combustion in cogeneration system**

**Carbon dioxide emissions from natural gas combustion in the cogeneration system, $E_{CS}$ (tonne $CO_2$/year)**:

$$E_{CS}\,(tonne\ CO_2\,/\,year) = \frac{AEC_{NG} \cdot EF_{NG}}{10^3} \qquad \textbf{(4.1)}$$

where $AEC_{NG}$ = annual energy consumption of natural gas in cogeneration system (GJ/year), and
$EF_{NG}$ = $CO_2$ emission factor of natural gas (kg $CO_2$/GJ, *lower* heating value basis)

### b) Methane emissions from natural gas combustion in cogeneration system

**Methane emissions from natural gas combustion in the cogeneration system,** $E_{met\ comb}$ **(tonne $CH_4$/year),** are given by:

$$E_{met\ comb}\,(tonne\ CH_4\,/\,year) = \frac{AEC_{NG} \cdot MEF}{10^6} \qquad \textbf{(4.2)}$$

where $AEC_{NG}$ = annual energy consumption of natural gas in the cogeneration system (GJ/year), and
$MEF$ = methane emission factor for natural gas combustion (kg $CH_4$/TJ, *lower* heating value basis)

**In units of carbon dioxide equivalent emissions,** $E_{equiv\ met\ comb}$ **(tonne $CO_2$ equiv/year)**

$$E_{equiv\ met\ comb}\,(tonne\ CO_2 - equiv\,/\,year) = E_{met\ comb} \cdot GWP\,(CH_4) \qquad \textbf{(4.3)}$$

where GWP ($CH_4$) = global warming potential of methane = 21

### c) Nitrous oxide emissions from natural gas combustion in cogeneration system

**Nitrous oxide emissions from natural gas combustion in the cogeneration system,** $E_{N_2O\ comb}$ **(tonne $N_2O$/year),** are given by:

$$E_{N_2O\ comb}\,(tonne\ CH_4\,/\,year) = \frac{AEC_{NG} \cdot NEF}{10^6} \qquad \textbf{(4.4)}$$

where $AEC_{NG}$ = annual energy consumption of natural gas in the cogeneration system (GJ/year), and
$NEF$ = nitrous oxide emission factor for natural gas combustion (kg $N_2O$/TJ, *lower* heating value basis)

**In units of carbon dioxide equivalent emissions,** $E_{equiv\ N_2O\ comb}$ **(tonne $CO_2$ equiv/year)**

$$E_{equiv\ N_2O\ comb}\,(tonne\ CO_2 - equiv\,/\,year) = E_{N_2O\ comb} \cdot GWP\,(N_2O) \qquad \textbf{(4.5)}$$

where *GWP ($N_2O$)* = global warming potential of nitrous oxide = 310

**d) Methane emissions from natural gas production and pipeline leaks in the transport and distribution of natural gas, including leakage within the industrial plant**

Total project emissions are given by the sum of the components analyzed above:

$$E_{total} = E_{CS} + E_{equiv\ met\ comb} + E_{equiv\ N_2O\ comb} + E_{equiv\ fug} \qquad \textbf{(4.8)}$$

***Parameters to be monitored***

| ID numbe | Data type | Data variabl e | Data unit | Measured (m), calculated (c) or estimated (e) | ɛecordin requenc | Proportion of data to be monitored | How will the data be archived? (electronic/ paper) | For how long is archived data to be kept? | Comment |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Volume of natural gas consumed | $MEC_{NG}$ | $m^3$ | m | monthly | 100% | paper (field record) electronic (spreadsheet) | Paper: 1 year, Electronic: 7 years | |
| 2. | Cogeneration electricity supplied to industrial plant | *MCEO* | MWh | m | monthly | 100% | electronic (spreadsheet) | Electronic: 7 years | |
| 3. | Cogeneration heat supplied to industrial plant | *MCHO* | GJ | m | monthly | 100% | electronic (spreadsheet) | Paper: 1 year Electronic: 7 years | |

***Quality Control (QC) and Quality Assurance (QA) Procedures***

| Data | Uncertainty level of data (High/Medium/Low) | Are QA/QC procedures planned for these data? | Outline explanation why QA/QC procedures are or are not being planned. |
|---|---|---|---|
| 1. | Low | Yes | These data will be used as supporting information to calculate emission reductions by project activity |
| 2. | Low | Yes | These data will be used as supporting information to calculate emission reductions by project activity |
| 3. | Low | Yes | These data will be used as supporting information to calculate emission reductions by project activity |
| 4. | Low | Yes | These data will be used as supporting information to calculate emission reductions by project activity |