Draft revision to the approved baseline and monitoring methodology AM0050
“Feed switch in integrated Ammonia-urea manufacturing industry”

I. SOURCE, DEFINITIONS AND APPLICABILITY

Source

This methodology is based on NM0165-rev “Feed switchover from Naphtha to Natural Gas (NG) at Phulpur plant of IFFCO”, whose baseline study and project design document were prepared by IFFCO - Indian Farmers Fertilizer Cooperative Ltd., India.

For more information regarding the proposal and its consideration by the Executive Board (hereinafter referred to as the Board) of the clean development mechanism (CDM) Executive Board please refer to case NM0165-rev on <http://cdm.unfccc.int/goto/MPappmeth>.

This methodology also refers to the latest version of the following tools:

- “Combined tool to identify the baseline scenario and demonstrate additionality”;¹
- “Tool to calculate the emission factor for an electricity system”;
- “Tool to calculate project or leakage CO₂ emissions from fossil fuel combustion”;
- “Tool to calculate baseline, project and/or leakage emissions from electricity consumption”;
- “Assessment of the validity of the original/current baseline and update of the baseline at the renewal of a crediting period”.

Definitions

Selected approach from paragraph 48 of the CDM modalities and procedures

“Existing actual or historical emissions, as applicable”

Applicability

This methodology is applicable to feed switch project activities in existing integrated ammonia-urea manufacturing facilities. In the project activity, natural gas is used solely, or in addition to existing hydrocarbon feedstock (i.e. naphtha, heavy oils, coal, lignite & coke etc) as feed which has a lower carbon

¹ Please refer to: <http://cdm.unfccc.int/goto/MPappmeth>.
to hydrogen ratio than existing hydrocarbon feedstock naphtha, which is the current practice in the plant. The emissions reductions are achieved as a result of a reduction in excess carbon, over and above that needed for the production of urea, leading to less CO₂ being released into the atmosphere.

This methodology is applicable to:

- Integrated ammonia-urea manufacturing facilities that involve partial or total switching from existing hydrocarbon feedstock naphtha to natural gas, as a feedstock with a lower carbon to hydrogen ratio (CHR) than that indicated in the baseline (naphtha);

- Integrated ammonia-urea manufacturing facilities plants that are not constrained by local regulations and/or programs from using existing feedstock naphtha as feed, neither obliged to use natural gas (NG) and/or liquefied natural gas (LNG) as feed;

- Project activities that do not result in the increase of the production capacity beyond 10% of the capacity existing before the project activity;

- Natural gas is sufficiently available in the region or country, e.g. future natural gas based capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity;

- Integrated ammonia-urea manufacturing facility plant in which the carbon in the existing naphtha feedstock used prior to implementation of the project activity is in excess of that needed in the urea production process. The excess carbon in the feed is emitted as CO₂ to the atmosphere;

- The integrated ammonia-urea manufacturing plant facility is an existing plant with a historical operation of at least three years prior to the implementation of the project activity;

- Project activities that do not result in changes in the production process (e.g. as a result of product change) other than the feed switch;

- If the use of natural gas in project activity results in a situation where the natural gas does not have sufficient carbon to meet the requirement of urea production, then the balance CO₂ required for use in urea production is recovered with the use of a Carbon Dioxide Recovery Plant (CDR) from CO₂ in flue gases emitted from an existing source of fossil fuel combustion for energy purposes within the project boundary. The CO₂ in the flue gases would have been emitted into the atmosphere in the absence of the project activity;

- The source of thermal energy for processing the feed is the combustion of fossil fuels in boilers both in the baseline scenario as well as in the project activity;

- Prior to the implementation of the project activity, no natural gas has been used in the integrated ammonia-urea manufacturing facility plant.

- The quantity of steam and electricity required for the ammonia production process is not affected by the project activity, i.e. it is the same with the use of naphtha and natural gas.

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2 In some situations, there could be price-elastic supply constraints (e.g. limited resources without possibility of expansion during the crediting period) that could mean that a project activity displaces natural gas that would otherwise be used elsewhere in an economy, thus leading to possible leakage. Hence, it is important for the project proponent to document that supply limitations will not result in significant leakage as indicated.
II. BASELINE METHODOLOGY

Project boundary

Flowchart:

- Feed
  - Feed treatment (Sulphur removal)
    - Syn-gas production (Reforming)
      - Syn-gas purification
        - Synthesis loop
          - Ammonia
          - CO2
            - Excess CO2 let out to atmosphere
        - Urea production
          - Urea
  - Flue gas
    - Flue gases

Inputs:
- Thermal energy
- Air
- Steam
- Electrical energy

Outputs:
- Ammonia
- CO2
- Urea
### Table 1: Emissions sources included in or excluded from the project boundary

<table>
<thead>
<tr>
<th>Source</th>
<th>Gas</th>
<th>Included?</th>
<th>Justification/Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Processing of feed</td>
<td>CO₂</td>
<td>Yes</td>
<td>Main emission source. CO₂ is produced in the reforming of the feed and is partially recovered for use in the production of urea. CO₂ in excess of required amount is released to the atmosphere</td>
</tr>
<tr>
<td></td>
<td>CH₄</td>
<td>No</td>
<td>Negligible fugitive CH₄ emissions may occur during the processing of the feed. These emissions (if any) would be essentially the same as in the project activity. Therefore, they are excluded for simplification</td>
</tr>
<tr>
<td></td>
<td>N₂O</td>
<td>No</td>
<td>Not applicable</td>
</tr>
<tr>
<td>Fuel used in furnaces</td>
<td>CO₂</td>
<td>Yes</td>
<td>Main emission source (flue gases) due to the combustion of fossil fuel to provide thermal energy for feed treatment (sulphur removal in hydrotreater and primary desulphurization unit) and the syn-gas production (reforming). Any CO₂ recovered from flue gases resulting from combustion of fossil fuel is deducted from this emission source</td>
</tr>
<tr>
<td>(thermal energy)</td>
<td>CH₄</td>
<td>No</td>
<td>Excluded for simplification, this is conservative</td>
</tr>
<tr>
<td></td>
<td>N₂O</td>
<td>No</td>
<td>Excluded for simplification, this is conservative</td>
</tr>
<tr>
<td>Baseline</td>
<td>CO₂</td>
<td>Yes/No</td>
<td>May be an important emission source. These emissions are expected to be the same or higher as compared to the project scenario. Excluded for simplification and because this is conservative</td>
</tr>
<tr>
<td></td>
<td>CH₄</td>
<td>No</td>
<td>Excluded for simplification, this is conservative</td>
</tr>
<tr>
<td></td>
<td>N₂O</td>
<td>No</td>
<td>Excluded for simplification, this is conservative</td>
</tr>
<tr>
<td>Fuel used in boilers</td>
<td>CO₂</td>
<td>Yes/No</td>
<td>May be an important emission source. These emissions are expected to be the same or higher as compared to the project scenario. Excluded for simplification and because this is conservative</td>
</tr>
<tr>
<td>(Steam generation)</td>
<td>CH₄</td>
<td>No</td>
<td>Excluded for simplification, this is conservative</td>
</tr>
<tr>
<td></td>
<td>N₂O</td>
<td>No</td>
<td>Excluded for simplification, this is conservative</td>
</tr>
<tr>
<td>Electricity requirement</td>
<td>CO₂</td>
<td>Yes/No</td>
<td>May be an important emission source. These emissions are expected to be the same or higher as compared to the project scenario. Excluded for simplification and because this is conservative</td>
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<tr>
<td></td>
<td>CH₄</td>
<td>No</td>
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<td>--------------------------------</td>
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<td></td>
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<tr>
<td></td>
<td>CO₂</td>
<td>Yes</td>
<td>Main emission source. CO₂ is produced in the reforming of the feed and is recovered for the production of urea. CO₂ in excess of that required for urea production, if any, is released into atmosphere</td>
</tr>
<tr>
<td></td>
<td>CH₄</td>
<td>No</td>
<td>Negligible fugitive CH₄ emissions may occur during the processing of the feed. These emissions (if any) would be essentially the same as in the baseline scenario. Therefore, they are excluded for simplification</td>
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<td></td>
<td>N₂O</td>
<td>No</td>
<td>Not applicable</td>
</tr>
<tr>
<td>Fuel used in furnaces (thermal</td>
<td>CO₂</td>
<td>Yes</td>
<td>Main emission source due to the combustion of fossil fuels. The project activity will result in lower thermal energy required as sulphur is negligible in NG/LNG. Any CO₂ recovered from flue gases resulting from combustion of fossil fuel is deducted from this emission source</td>
</tr>
<tr>
<td>energy)</td>
<td>CH₄</td>
<td>No</td>
<td>These emissions are expected to be the same or lower as compared to the baseline scenario</td>
</tr>
<tr>
<td></td>
<td>N₂O</td>
<td>No</td>
<td>These emissions are expected to be the same or lower as compared to the baseline scenario</td>
</tr>
<tr>
<td>Project Activity</td>
<td>CO₂</td>
<td>NoYes</td>
<td>May be an important emission source. These emissions are expected to be the same or lower as compared to the baseline scenario. In case these emissions are higher than the baseline scenario this should be included.</td>
</tr>
<tr>
<td></td>
<td>CH₄</td>
<td>No</td>
<td>Excluded for simplification. This emission source is assumed to be very small! These emissions are expected to be the same or lower as compared to the baseline scenario.</td>
</tr>
<tr>
<td></td>
<td>N₂O</td>
<td>No</td>
<td>Excluded for simplification. This emission source is assumed to be very small! These emissions are expected to be the same or lower as compared to the baseline scenario.</td>
</tr>
<tr>
<td>Fuel used in boilers (Steam</td>
<td>CO₂</td>
<td>YesNo</td>
<td>May be an important emission source. These emissions are expected to be the same or lower as compared to the baseline scenario. In case these emissions are higher than the baseline scenario this should be included.</td>
</tr>
<tr>
<td>generation)</td>
<td>CH₄</td>
<td>No</td>
<td>Excluded for simplification. This emission source is assumed to be very small! These emissions are expected to be the same or lower as compared to the baseline scenario.</td>
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</tr>
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<td>Electricity requirement</td>
<td>CO₂</td>
<td>YesNo</td>
<td>May be an important emission source. These emissions are expected to be the same or lower as compared to the baseline scenario. In case these emissions are higher than the baseline scenario this should be included.</td>
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<tr>
<td></td>
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</thead>
<tbody>
<tr>
<td>Energy consumed by CDR plant</td>
<td>CO₂</td>
<td>Yes</td>
<td>If a CDR plant is also part of the project activity, then the emissions due to the production of energy (steam and electricity) for the operation of this equipment must also be considered</td>
</tr>
<tr>
<td></td>
<td>CH₄</td>
<td>No</td>
<td>Not applicable</td>
</tr>
<tr>
<td></td>
<td>N₂O</td>
<td>No</td>
<td>Not applicable</td>
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</tbody>
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**Combined Procedure to identify the baseline scenario and demonstrate additionality**

The most plausible baseline scenario and the additionality shall be identified and determined according to the latest version of the “Combined tool to identify the baseline scenario and demonstrate additionality”.

**Step 1: Identification of alternative scenarios**

**Step 1a. Define alternative scenarios to the proposed CDM project activity**

In applying Step 1 of the tool, identify all alternative scenarios that are available to the project participants and that provide outputs or services with comparable quality, properties and application areas as the proposed CDM project activity.

These alternative scenarios shall include, *inter alia*:

- The continuation of current practice, i.e. usage of *existing feedstock naphtha* alone as feed for the production of urea, resulting in CO₂ surpluses that are released to the atmosphere;
- Partial substitution of *existing feedstock naphtha* with NG/LNG so as to reduce the CO₂ surpluses released to atmosphere for similar output of urea;
- Complete switchover from *existing feedstock* to NG/LNG resulting in the reduction of CO₂ surpluses and equivalent emissions for similar output of urea;
- Usage of *existing feedstock* as feed and production of CO₂ surpluses, but with capture of the CO₂ surpluses for its use in other applications, which would otherwise be released to the atmosphere, for its use in other applications.

Note that the alternatives proposed are only indicative. Project proponents may identify other alternatives.

**Sub-step 1b. Consistency with mandatory applicable laws and regulations**

Eliminate alternatives that are not in compliance with all applicable legal and regulatory requirements.

**Step 2: Investment Analysis**

Compare the economic attractiveness without considering the impacts of the CDM for all alternatives that are remaining by applying Step 3 of the “Combined tool to identify the baseline scenario and demonstrate additionality” agreed by the CDM Executive Board. National policies or regulations or other benefits that are related to the increase of the production capacity, which may have an effect on the types of feed used, should also be taken into consideration.
This methodology is only applicable if the “usage of existing feedstock naphtha alone as feed for the production of urea, resulting in CO₂ surpluses that are released to the atmosphere” throughout the crediting period is the most plausible baseline scenario.

Note: the methodology cannot be used if the most plausible baseline scenario is the use of both existing feedstock naphtha and NG/LNG as feedstock.

**Step 3: Common practice analysis**

Demonstrate that the project activity is not a common practice in the relevant country and sector. The common practice analysis is to be carried out as follows:

**Sub-step 3a. Analyze other activities similar to the proposed project activity:**

Provide an analysis of any other feed switch activity implemented previously or currently underway that is similar to the proposed project activity. Other activities are considered similar if they are in the same country/region, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology, access to financing, etc. Other CDM project activities are not to be included in this analysis. Provide quantitative information where relevant.

**Sub-step 3b. Discuss any similar options that are occurring:**

If similar activities are widely observed and commonly carried out, it calls into question the claim that the proposed project activity is financially unattractive. Therefore, if similar activities are identified above, then it is necessary to demonstrate why the existence of these activities does not contradict the claim that the proposed project activity is financially unattractive. This can be done by comparing the proposed project activity to the other similar activities, and pointing out and explaining essential distinctions between them that explain why the similar activities enjoyed certain benefits that rendered them financially attractive (e.g. subsidies or other financial flows) to which the proposed project activity is subject. Essential distinctions may include a serious change in circumstances under which the proposed CDM project activity will be implemented when compared to circumstances under which similar activities have been carried out. For example, promotional policies may have ended, leading to a situation in which the proposed CDM project activity would not be implemented without the incentives provided by the CDM. The change must be fundamental and verifiable.

*If all steps are satisfied, then the project is considered additional.*

**Baseline emissions**

Baseline emissions are calculated as follows:

\[
BE_{y} = BE_{feed,y} + BE_{heat,y} \tag{1}
\]

\[
BE_{y} = BE_{unadj,y} \times \min \left(1, \frac{P_{\text{Urea BL y}}}{P_{\text{Urea PJ y}}} \right) \tag{1}
\]
Where:

- \( BE_{\text{Feed},y} \): Unadjusted baseline emissions in year \( y \) due to the use of naphtha as feed for the production of urea, in tCO₂

- \( BE_{\text{unadj},y} \): Unadjusted baseline emissions in year \( y \), in tCO₂

- \( BE_{\text{Heat},y} \): Emissions due to the use of naphtha as feed for the production of urea, in tCO₂

- \( P_{\text{Urea,BL},k} \): Average urea production in the most recent three years prior to the implementation of the project activity, in tonnes

- \( P_{\text{Urea,P},y} \): Production of urea in each year \( y \) of the crediting period, in tonnes

\[
BE_{\text{unadj},y} = BE_{\text{Feed},y} + BE_{\text{Heat},y}\quad (2)
\]

Where:

- \( BE_{\text{Feed},y} \): Emissions due to the use of existing feedstock as feed for the production of urea, in tCO₂

- \( BE_{\text{Heat},y} \): Emissions due to the production of thermal energy used in the furnaces (feed treatment and reforming), in tCO₂

**Emissions due to the use of existing feedstock naphtha as feed (\( BE_{\text{Feed},y} \))**

The emissions due to the use of existing feedstock naphtha as feed for the production of urea are calculated as follows:

\[
BE_{\text{Feed},y} = BE_{\text{Naphtha},y} - BS_{\text{Urea},y}\quad (32)
\]

Where:

- \( BE_{\text{Naphtha},y} \): Quantity of CO₂ that would be produced from existing feedstock naphtha in the baseline, in tCO₂

- \( E_{\text{Existing feedstock},y} \): Equivalent CO₂ quantity of the carbon (C) that is contained in the product of urea produced, in tCO₂

- \( BS_{\text{Urea},y} \): Equivalent CO₂ quantity of the carbon (C) that is included in the product of urea produced, in tCO₂

The quantity of CO₂ that would be produced from existing feedstock naphtha in the baseline is calculated as:

\[
BE_{\text{Naphtha},y} \frac{44}{12} P_{\text{Urea,P},y} \frac{SFC_{\text{Naphtha},y}}{CF_{\text{Naphtha,BL}}}
\]

\[
BE_{\text{Existing feedstock},y} = \frac{44}{12} \times P_{\text{Urea,P},y} \times SFC_{\text{Existing feedstock}} \times CF_{\text{Existing feedstock,BL}}\quad (43)
\]
Where:

\[ P_{Urea,PJ,y} \]  
Production of urea in each year \( y \) of the crediting period, in tonnes

\[ SFC_{Naphtha} \]  
Specific feed consumption ratio for the production of urea in the three most recent years previous to the implementation of the project activity, tonnes of existing feedstock naphtha/tonnes of urea

\[ CF_{Naphtha,BL} \]  
Carbon fraction of existing feedstock naphtha used in the baseline as feedstock, in tonnes of carbon/tonnes of existing feedstock naphtha

44/12  
Ratio between the molecular weights of CO\(_2\) and carbon, mass units/mass units

The specific feed consumption ratio is calculated as follows:

\[
SFC_{Existing feedstock} = \frac{\sum_{k=1}^{3} F_{Existing feedstock,BL,k}}{\sum_{k=1}^{3} P_{Urea,BL,k}}
\]  
(5.4)

Where:

\[ P_{Urea,BL,k} \]  
Production of urea in each one of the three most recent years \( k \) previous to the implementation of the project activity, in tonnes

\[ F_{Existing feedstock,BL,k} \]  
Quantity of naphtha existing feedstock used as feed in each one of the three most recent years \( k \) previous to the implementation of the project activity, in tonnes

In case more than one feedstock is used \( CF_{Existing feedstock,BL} \) is the lowest carbon fraction of feedstock used for the three most recent years \( k \) previous to the implementation of the project activity.

The quantity of CO\(_2\) contained in urea produced required to produce urea is calculated as follows:

\[
BS_{Urea,y} = \frac{44}{60} \times P_{Urea,PJ,y}
\]  
(6.5)

Where:

44/60  
\( =44/12 \times 12/60 \). 44/12 represents conversion factor from carbon to carbon dioxide and 12/60 is ratio of carbon mass (each urea molecule has one molecule of carbon) to urea mass in one molecule of urea (molecular weight 60)

**Emissions due to the fuel used in production of thermal energy in the furnaces (BE\(_{Heat,y} \))**

The CO\(_2\) emissions from fuel used for production of thermal energy are calculated as follows:

\[
BE_{Heat,y} = P_{Urea,PJ,y} \times SFC_{Naphtha} \times EF_{CO2,BL,y}
\]
\[ BE_{Heat,y} = P_{\text{Urea, } PJ,y} \times SEC_{\text{Existing feedstock}} \times EF_{\text{CO}_2, \text{BL},y} \] (7.6)

Where:

\( EF_{\text{CO}_2, \text{BL},y} \) CO₂ emission factor for the baseline fuel that would be used in the furnaces (feed treatment and reforming) in each year \( y \) of the crediting period, in tCO₂/TJ

\( SEC_{\text{Naphtha}} \) Specific thermal energy consumption ratio in the urea production process (feed treatment and reforming) in the three most recent years previous to the implementation of the project activity, TJ/tonnes of urea

\( SEC_{\text{Existing feedstock}} \)

The emission factor for the fuel that would be used in the furnaces \( (EF_{\text{CO}_2, \text{BL},y}) \) must be chosen as the lowest of the emission factors among the fuels used in the three most recent years prior to the implementation of the project activity and the fuels used in the relevant year \( y \) of the crediting period. In the cases where the fuel is not directly monitored (in gasification of low sulfur heavy stock (LSHS) etc) the feed used as fuel should be considered in \( SFC_{\text{Existing feedstock}} \).

For the determination of emission factors, guidance from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available any) may be used if they are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner and the choice should be justified and documented in the CDM-PDD. Where measurements are undertaken, project participants may estimate the emission factors or net calorific values ex ante in the CDM-PDD and should document the measurement results after implementation of the project activity in their monitoring reports.

The specific thermal energy consumption ratio is calculated as follows:

\[ SEC_{\text{Existing feedstock}} = \left[ \frac{\sum_k \sum_i (FC_{BL,j,k} \times NCV_{i,k})}{\sum_k P_{\text{Urea, } BL,k}} \right] \] (8.2)

Where:

\( FC_{BL,j,k} \) Quantity of fuel of type \( i \) consumed in the furnaces (feed treatment and reforming) in each one of the most recent three years \( k \) previous to the implementation of the project activity, in tonnes

\( NCV_{i,k} \) Net calorific value of fuel type \( i \) in each one of the most recent three years \( k \) previous to the implementation of the project activity, in TJ/tonnes

\( k \) The most recent three years prior to the implementation of the project activity

\( i \) Fossil fuel types used in the years \( k \)
Project emissions

Project activity emissions are calculated as follows:

$$PE_y = PE_{Feed,y} + PE_{Heat,y} + PE_{CDR,y} + PE_{Utility,y}$$  \hspace{1cm} (9.8)

Where:

- $PE_{Feed,y}$: Emissions due to the use of NG/LNG as feed for the production of urea in each year $y$ of the crediting period, in tCO$_2$
- $PE_{Heat,y}$: Emissions due to fuel consumption for the purpose of production of thermal energy used in the furnaces (feed treatment and reforming) after deducting the CO$_2$ recovered by the CDR plant (if any) in each year $y$ of the crediting period, in tCO$_2$
- $PE_{CDR,y}$: Emissions due to the production of energy used by the CDR plant (if any) in each year $y$ of the crediting period, in tCO$_2$
- $PE_{Utility,y}$: Emissions due to the increased usages of steam and/or electricity in each year $y$ of the crediting period, in tCO$_2$

Emissions due to the use of NG/LNG as feed ($PE_{Feed,y}$)

The emissions due to the use of NG/LNG as feed for the production of urea are calculated as follows:

$$PE_{Feed,y} = PE_{PJ,y} - PS_{Urea,y}$$

Where:

- $PE_{PJ,y}$: Quantity of CO$_2$ produced from NG/LNG as feed in each year $y$ of the crediting period, in tCO$_2$
- $PS_{Urea,y}$: Quantity of CO$_2$ required for the production of urea in each year $y$ of the crediting period, in tCO$_2$

The quantity of CO$_2$ produced from NG/LNG as feed is calculated as follows:

$$PE_{PJ,y} = \frac{44}{12} \left( F_{NG,PJ,y} \times CF_{NG} + F_{Naphtha,PJ,y} \times CF_{Naphtha,PJ} \right)$$

$$PE_{PJ,y} = \frac{44}{12} \times \left( F_{NG,PJ,y} \times CF_{NG} + F_{Existing feedstock,PJ,y} \times CF_{Existing feedstock,PJ} \right)$$  \hspace{1cm} (11.40)
Where:

\[ F_{NG,PJ,y} \] Consumption of NG/LNG as feed during the year \( y \) of the crediting period, in tonnes.

If the available data are measured in volume units use the appropriate density of NG, corrected for temperature and pressure, to calculate the equivalent mass.

\[ CF_{NG} \] Carbon content, expressed as weight fraction, of NG/LNG used as feed during year \( y \) of the crediting period, in tonnes of carbon/tonnes of NG/LNG.

\[ F_{\text{Existing feedstock, PJ,y}} \] Consumption of \textit{existing feedstock naphtha} as feed during the year \( y \) of the crediting period, in tonnes.

\[ CF_{\text{Existing feedstock, PJ,y}} \] Carbon content, expressed as weight fraction, of \textit{existing feedstock naphtha} used as feed during year \( y \) of the crediting period, in tonnes of carbon/tonnes of \textit{feedstock naphtha}.

The quantity of CO\(_2\) required for the production of urea is calculated as follows:

\[ pS_{\text{Urea,y}} = \frac{44}{60} p_{\text{Urea,PJ,y}} \] \hspace{1cm} (11)

\textit{Emissions from thermal energy (PE_{Heat,y})}

Emissions due to the \textit{fuel used in production of thermal energy used in the furnaces (feed treatment and reforming)} is calculated according to latest version of the ‘Tool to calculate project or leakage CO\(_2\) emissions from fossil fuel combustion’ where PE\(_{\text{Heat,y}}\) is equal to PE\(_{\text{FC,y}}\) of the tool, as follows:

\[ PE_{\text{Heat,y}} = (\sum_{i} FC_{i,y} \times NCV_{i,y}) \times EF_{\text{CO}_2,PJ,y} \] \hspace{1cm} (12)

Where:

\[ FC_{i,y} \] Quantity of fuel type \( i \) consumed in the furnaces (feed treatment and reforming) in each year \( y \) of the crediting period, in mass or volume units.

\[ NCV_{i,y} \] Net calorific value of fuel type \( i \) in each year \( y \) of the crediting period, in TJ/mass or volume units.

\[ EF_{\text{CO}_2,PJ,y} \] \( \text{CO}_2 \) emission factor of the fuel type with the lowest emission factor among all the fossil fuels used in the furnaces (feed treatment and reforming) in each year \( y \) of the crediting period, in t\( \text{CO}_2/\text{TJ} \).

For the determination of emission factors, guidance from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available) may be used if they are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner and the choice should be justified and documented in the CDM PDD. Where measurements are undertaken, project participants may estimate the emission factors or net calorific values ex-ante in the
CDM PDD and should document the measurement results after implementation of the project activity in their monitoring reports.

**Emissions from CDR (PE\textsubscript{CDR,y})**

If installation of CDR plant is also carried out in the project activity as a means to make up for reduced carbon feed, then the emissions due to the operation of the CDR plant need also to be accounted for in the project activity emissions. These emissions would arise from the production of energy (electricity and steam) required to the operation of the CDR plant. They are calculated as follows:

\[
PE\textsubscript{CDR,y} = PE\textsubscript{CDR,elec,y} + PE\textsubscript{CDR,steam,y} \tag{12}
\]

Where:

- \(PE\textsubscript{CDR,elec,y}\) Emissions due to the production of electricity used for the operation of the CDR plant in each year \(y\) of the crediting period, in tCO\(_2\)

- \(PE\textsubscript{CDR,steam,y}\) Emissions due to the production of steam used for the operation of the CDR plant in each year \(y\) of the crediting period, in tCO\(_2\)

The emissions due to the production of electricity used for the operation of the CDR plant should be calculated as per the latest version of the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption”. \(PE\textsubscript{CDR,elec,y}\) corresponds to the parameter \(PE\textsubscript{EC,y}\) Project emissions from electricity consumption in year \(y\), in the tool referred above. They are calculated as follows:

\[
PE\textsubscript{CDR,elec,y} = EC\textsubscript{CDR,elec,y} \times EF\textsubscript{elec,y} \tag{14}
\]

Where:

- \(EC\textsubscript{CDR,elec,y}\) Quantity of electricity consumed by the CDR plant in each year \(y\) of the crediting period, in MWh. Measured in the project activity.

- \(EF\textsubscript{elec,y}\) CO\(_2\) emission factor for electricity during each year \(y\) of the crediting period, in tCO\(_2\)/MWh. Calculated as per equation below.

The electrical energy supplied to the CDR plant might be coming from either grid or captive power generation or a mix of both. Thus the CO\(_2\) emission factor for electrical energy would be calculated as follows:

**Option 1 - Grid power**

If the electricity used is obtained from the grid:

\[
EF\textsubscript{elec,grid,y} = EF\textsubscript{grid,y} \tag{15}
\]

Where \(EF\textsubscript{grid,y}\) in tCO\(_2\)/MWh, is the emission factor of the grid that must be calculated as the generation weighted average emissions per electricity unit of all generating sources serving the system or assumed as a default value of 1.3 tCO\(_2\)/MWh.

**Option 2 - Captive power**
For captive power supply the emission factor would be $EF_{\text{elec},y} = EF_{\text{captive},y}$ calculated as follows:

$$
EF_{\text{captive},y} = \frac{44}{12} \sum_{i} FC_{\text{CDR,captive},i,y} \cdot NCV_{i,y} \cdot EF_{i,y} / TEP_{\text{CDR,captive},y}
$$

(15)

Where:

- $EF_{\text{captive},y}$: Emission factor for captive power generation (tCO$_2$/MWh).
- $FC_{\text{CDR,captive},i,y}$: Amount of fossil fuel of type $i$ used in the captive power plant in each year $y$ of the crediting period, in mass or volume units.
- $TEP_{\text{CDR,captive},y}$: Total electricity produced by the captive power plant in year $y$, in MWh.
- $EF_{i,y}$: Emission factor of fuel type $i$ used for steam generation in each year $y$ of the crediting period, tCO$_2$/TJ.

**Option 3: Both grid and captive power**

For both grid and captive power supply the emission factor $EF_{\text{elec},y}$ would be calculated as the weighted average of grid and captive power, as follows:

$$
EF_{\text{elec},y} = \frac{EC_{\text{grid},y} \cdot EF_{\text{grid},y} + EC_{\text{captive},y} \cdot EF_{\text{captive},y}}{EC_{\text{grid},y} + EC_{\text{captive},y}}
$$

(16)

Where:

- $EC_{\text{grid},y}$: Quantity of electricity obtained from the grid by the project activity during each year $y$ of the crediting period, in MWh.
- $EC_{\text{captive},y}$: Quantity of electricity obtained from a captive power plant by the project activity during each year $y$ of the crediting period, in MWh.

The emissions due to the production of steam used for the operation of the CDR plant are calculated as follows:

$$
P_{E_{\text{CDR,steam},y}} = EC_{\text{CDR,steam},y} \times EF_{\text{Boiler},y}
$$

(13)

Where:

- $EC_{\text{CDR,steam},y}$: Quantity of thermal energy (steam) used for the operation of the CDR plant during each year $y$, in TJ. The calculation of the amount of thermal energy (steam) used for the operation of the CDR plant must take into consideration the pressure and temperature in which the steam is produced ($T_{\text{steam}}$, $P_{\text{steam}}$). The specific enthalpy is a function of pressure and temperature and can be obtained from steam tables.
- $EF_{\text{Boiler},y}$: Emission factor of the steam generator during each year $y$, tCO$_2$/TJ.
The annual equivalent energy for steam consumption is calculated as follows:

\[
EC_{CDR,steam,y} = SC_{CDR,y} \times (E_{steam} - E_{feedwater})
\]

Where:

\(SC_{CDR,y}\) Quantity Demand of steam required for the operation of the CDR plant in each year \(y\) of the crediting period, in tonnes

\(E_{steam}\) Specific enthalpy of the steam at the steam generator outlet, in TJ/tonnes. Obtained from steam tables using the measured temperature \(T_{steam}\) and pressure \(P_{steam}\) of the steam in the steam generator outlet

\(E_{feedwater}\) Specific enthalpy of the feed water at the steam generator inlet, in TJ/tonnes. Obtained from steam tables using the measured temperature \(T_{fw}\) and pressure \(P_{fw}\) of the feedwater in the steam generator inlet

The emission factor of the steam generator is calculated as follows:

\[
EF_{Boiler,y} = \sum_{i} \frac{FC_{CDR,steam,i,y} \times NCV_{i,y} \times EF_{i,y}}{TSP_{CDR,steam,y} \times (E_{steam} - E_{feedwater})}
\]

Where:

\(FC_{CDR,steam,i,y}\) Amount of fuel type \(i\) consumed in the steam generator in each year \(y\) of the crediting period, in mass or volume units

\(SP_{CDR,steam,y}\) Total amount of steam produced by the steam generator in each year \(y\) of the crediting period, in tonnes

\(EF_{i,y}\) Emission factor of fuel type \(i\) used for steam generation in each year \(y\) of the crediting period, tCO₂/TJ

**Emissions from increased steam and/or electricity consumption (PE\(_{utility,y}\))**

In case the project activity results in an increase in specific consumption of steam and/or electricity, the corresponding emissions should be accounted for as project emissions however in case of decrease or no change in specific consumption of steam and/or electricity the project emissions due to consumption of utility is considered as zero.

\[
PE_{Utility,y} = PE_{utility,elec,y} + PE_{utility,steam,y}
\]

Where:

\(PE_{utility,elec,y}\) Emissions due to the increase in electricity used in each year \(y\) of the crediting period, in tCO₂

\(PE_{utility,steam,y}\) Emissions due to the increase in steam used in each year \(y\) of the crediting period, in tCO₂
The emissions due to increased consumption of electricity after implementation of project activity are calculated as follows:

\[ PE_{utility,elec,y} = \max\{ 0, \frac{EC_{utility,elec,y}}{P_{Urea,PJ,y}} \times \left( \frac{1}{3} \sum_{k=1}^{3} \frac{EC_{utility,elec,BL,k}}{P_{Urea,BL,k}} \right) \times P_{Urea,PJ,y} \times EF_{utility,elec,y} \} \]  \hspace{1cm} (17)

Where:

- \( EC_{utility,elec,y} \): Quantity of electricity consumed by the project activity plant in each year \( y \) of the crediting period, in MWh
- \( EC_{utility,BL,k} \): Quantity of electricity consumed during the most recent three years of baseline in MWh
- \( EF_{utility,elec,y} \): CO\(_2\) emission factor for electricity used for utilities during each year \( y \) of the crediting period, in tCO\(_2\)/MWh

For \( EF_{utility,elec,y} \), refer to the latest “Tool to calculate baseline, project and/or leakage emissions from electricity consumption”.

The emissions due to increased consumption of steam after implementation of project activity are calculated as follows:

The emissions due to the production of additional steam used for the plant utilities are calculated as follows:

\[ PE_{utility,steam,y} = EC_{utility,steam,y} \times EF_{utility,Boiler,y} \]  \hspace{1cm} (18)

Where:

- \( EC_{utility,steam,y} \): Additional quantity of thermal energy (steam) used for the operation of the utilities in plant, in TJ. The calculation of the amount of thermal energy (steam) used for the operation of the utilities must take into consideration the pressure and temperature in which the steam is produced (\( T_{utility,steam}, P_{utility,steam} \)). The specific enthalpy is a function of pressure and temperature and can be obtained from steam tables
- \( EF_{utility,Boiler,y} \): Emission factor of the steam generator, tCO\(_2\)/TJ

The annual equivalent energy for additional steam consumption for plant utilities is calculated as follows:

\[ EC_{utility,steam,y} = \max\{ 0, \frac{SC_{utility,steam,y}}{P_{Urea,PJ,y}} - \left( \frac{1}{3} \sum_{k=1}^{3} \frac{SC_{utility,steam,BL,k}}{P_{Urea,BL,k}} \right) \times (EF_{utility,steam} - EF_{utility,feedwater}) \times P_{Urea,PJ,y} \} \]  \hspace{1cm} (19)
Where:

\[ \text{SC}_{\text{util}, \text{steam}, y} \] Quantity of steam consumed by the project activity plant in each year \( y \) of the crediting period, in tonnes of steam

\[ \text{SC}_{\text{util}, \text{steam}, BLA} \] Quantity of steam consumed during the most recent three years of baseline in tonnes of steam

\[ E_{\text{util}, \text{steam}} \] Specific enthalpy of the steam at the steam generator outlet used for utility steam, in TJ/tonnes. Obtained from steam tables using the measured temperature \( T_{\text{util}, \text{steam}} \) and pressure \( P_{\text{util}, \text{steam}} \) of the steam in the steam generator outlet

\[ E_{\text{util}, \text{feedwater}} \] Specific enthalpy of the feed water at the steam generator inlet used for utility steam, in TJ/tonnes. Obtained from steam tables using the measured temperature \( T_{\text{util}, \text{fw}} \) and pressure \( P_{\text{util}, \text{fw}} \) of the feedwater in the steam generator inlet

The emission factor of the steam generator is calculated as follows:

\[
E_{\text{util}, \text{Boiler}, y} = \frac{\sum_i FC_{\text{util}, \text{steam}, i, y} \times NCV_{i, y} \times EF_{i, y}}{TSP_{\text{util}, \text{steam}, y} \times (E_{\text{util}, \text{steam}} - E_{\text{util}, \text{feedwater}})}
\]  

Where:

\[ FC_{\text{util}, \text{steam}, i, y} \] Amount of fuel type \( i \) consumed in the steam generator used for utility steam in each year \( y \) of the crediting period, in mass or volume units

\[ TSP_{\text{util}, \text{steam}, y} \] Total amount of steam produced by the steam generator used for utility steam in each year \( y \) of the crediting period, in tonnes

\[ FC_{i, y} \] Quantity of fuel type \( i \) consumed in the furnaces (feed treatment and reforming) in each year \( y \) of the crediting period, in mass or volume units

\[ NCV_{i, y} \] Net calorific value of fuel type \( i \) in each year \( y \) of the crediting period, in TJ/mass or volume units

\[ EF_{i, y} \] Emission factor of fuel type \( i \) used for steam generation in each year \( y \) of the crediting period, tCO2/TJ

Leakage

The leakage \( (LE_y) \) in the project activity would be due to feed extraction, processing, liquefaction, transportation, re-gasification and distribution of feed outside of the project boundary. This includes mainly: (i) fugitive CH4 emissions; (ii) CO2 emissions from the process of CO2 removal from the raw natural gas stream in order to upgrade the natural gas to the required market conditions; and (iii) CO2 emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources shall be considered:

3 The Meth Panel is undertaking further work on the estimation of leakage emission sources in case of fuel switch project activities. This approach may be revised based on outcome of this work.
- Fugitive CH₄ emissions associated with feed extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity;

- CO₂ emissions from the process of CO₂ removal from the raw natural gas stream in order to upgrade the natural gas to the required market conditions; and

- In the case LNG is used in the project plant: CO₂ emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Thus, leakage emissions are calculated as follows:

\[ LE_y = LE_{CH_4,y} + LE_{LNG,CO_2,y} \]

\[ LE_y = LE_{CH_4,y} + LE_{CO_2,y} + LE_{LNG,CO_2,y} \] (21)

Where:

- \( LE_y \) Leakage emissions in the year \( y \) (tCO₂e)
- \( LE_{CH_4,y} \) Leakage emissions due to fugitive upstream CH₄ emissions in the year \( y \), in tCO₂
- \( LE_{CO_2,y} \) Leakage emissions due to the removal of CO₂ from the raw natural gas stream in year \( y \) (tCO₂)
- \( LE_{LNG,CO_2,y} \) Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year \( y \), in tCO₂

**Fugitive methane emissions**

For the purpose of determining fugitive methane emissions associated with the production – and in case of natural gas, the transportation and distribution of the fuels – project participants should multiply the quantity of natural gas consumed as feed with a methane emission factor for these upstream emissions \( (EF_{NG,upstream,CH_4}) \) as follows:

\[ LE_{CH_4,y} = F_{NG,PJ,y} \times NCV_{NG,y} \times EF_{NG,upstream,CH_4} \times GWP_{CH_4} \] (22)

Where:

- \( F_{NG,PJ,y} \) Consumption of NG/LNG as feed during the year \( y \) of the crediting period, in m³. If the available data are measured in mass units, use the appropriate density of NG/LNG, corrected for temperature and pressure, to calculate the equivalent volume
- \( NCV_{NG,y} \) Average net calorific value of the natural gas combusted during the year \( y \), in TJ/m³
- \( EF_{NG,upstream,CH_4} \) CH₄ emission factor for upstream fugitive methane emissions from production, transportation and distribution of natural gas feed supplied to final consumers, in tCH₄/TJ
- \( GWP_{CH_4} \) Is the global warming potential of methane = 21
Where reliable and accurate national data on fugitive CH₄ emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is available, project participants should use this data to determine average emission factors by dividing the total quantity of CH₄ emissions by the quantity of fuel produced or supplied respectively. Where such data is not available, project participants may use the default values provided in the table below. Note that the emission factor for fugitive upstream emissions for natural gas ($EF_{NG,upstream,CH4}$) should include fugitive emissions from production, processing, transport and distribution of natural gas, as indicated in the table below.

### Table 2: Default emission factors for fugitive CH₄ upstream emissions

<table>
<thead>
<tr>
<th>Activity</th>
<th>Unit</th>
<th>Default emission factor</th>
<th>Reference for the underlying emission factor range in Volume 2 of the 2006 Revised IPCC Guidelines</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Natural gas</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Developed countries</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas production</td>
<td>Gg per $10^6$ m³ gas production</td>
<td>3.8E-04 to 2.3E-03</td>
<td>Table 4.2.4, p. 4.48</td>
</tr>
<tr>
<td>Gas processing</td>
<td>Gg per $10^6$ m³ raw gas feed</td>
<td>4.8E-04 to 10.3E-03</td>
<td>Table 4.2.4, p. 4.48</td>
</tr>
<tr>
<td>Sour gas plant</td>
<td>Gg per $10^6$ m³ raw gas feed</td>
<td>9.7E-05</td>
<td>Table 4.2.4, p. 4.48</td>
</tr>
<tr>
<td>Gas transmission &amp; Storage</td>
<td>Gg per $10^6$ m³ of marketable gas</td>
<td>6.6E-05 to 4.8E-04</td>
<td>Table 4.2.4, p. 4.49</td>
</tr>
<tr>
<td>Storage</td>
<td>Gg per $10^6$ m³ of marketable gas</td>
<td>2.5E-05</td>
<td>Table 4.2.4, p. 4.49</td>
</tr>
<tr>
<td>Gas distribution</td>
<td>Gg per $10^6$ m³ of utility sales</td>
<td>1.1E-03</td>
<td>Table 4.2.4, p. 4.50</td>
</tr>
<tr>
<td>Developing countries and countries with economies in transition</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas production</td>
<td>Gg per $10^6$ m³ gas production</td>
<td>3.8E-04 to 2.4E-02</td>
<td>Table 4.2.5, p. 4.55</td>
</tr>
<tr>
<td>Gas processing</td>
<td>Gg per $10^6$ m³ raw gas feed</td>
<td>4.8E-04 to 1.1E-03</td>
<td>Table 4.2.5, p. 4.55</td>
</tr>
<tr>
<td>Sour gas plant</td>
<td>Gg per $10^6$ m³ raw gas feed</td>
<td>9.7E-05 to 2.2E-04</td>
<td>Table 4.2.5, p. 4.55</td>
</tr>
</tbody>
</table>

4 GHG inventory data reported to the UNFCCC as part of national communications can be used where country specific approaches (and not IPCC Tier 1 default values) have been used to estimate emissions.
<table>
<thead>
<tr>
<th>Activity</th>
<th>Unit</th>
<th>Default emission factor</th>
<th>Reference for the underlying emission factor range in Volume 2 of the 2006 Revised IPCC Guidelines</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas transmission and storage</td>
<td>Transmission Gg per 10^6 m^3 of marketable gas</td>
<td>16.6E-05 to 1.1E-03</td>
<td>Table 4.2.5, p. 4.57</td>
</tr>
<tr>
<td>Storage</td>
<td>Gg per 10^6 m^3 of marketable gas</td>
<td>2.5E-05 to 5.8E-05</td>
<td>Table 4.2.5, p. 4.57</td>
</tr>
<tr>
<td>Gas distribution</td>
<td>Gg per 10^6 m^3 of utility sales</td>
<td>1.1E-03 to 2.5E-03</td>
<td>Table 4.2.5, p. 4.57</td>
</tr>
</tbody>
</table>

Note: The emission factor should be selected in order to ensure conservativeness in estimation of emission reduction.

### Upstream emissions due to CO₂ removal from raw natural gas stream (LE₂CO₂,y)

In processing natural gas, CO₂ contained in the raw gas is removed and usually vented to the atmosphere. The CO₂ is removed to upgrade the gas to specifications required for commercial application. Emissions from venting of the CO₂ only need to be estimated if the average CO₂ content of the raw gas, which is processed in the gas processing plants supplying the applicable gas transmission and distribution system, is higher than 5% on a volume basis. In this case, the leakage emissions LE₂CO₂,y are to be estimated as follows:

\[
LE_{\text{CO}_2,y} = F_{\text{NG},PJ,y} \times \frac{r_{\text{CO}_2}}{1 - r_{\text{CO}_2}} \times \rho_{\text{CO}_2}
\]

Where:
- \( LE_{\text{CO}_2,y} \): Leakage emissions due to the removal of CO₂ from the raw natural gas stream in year \( y \) (tCO₂)
- \( F_{\text{NG},PJ,y} \): Quantity of natural gas combusted in the project plant in year \( y \) (m³)
- \( r_{\text{CO}_2} \): Average CO₂ content in the raw natural gas stream on volume basis (ratio)
- \( \rho_{\text{CO}_2} \): Density of CO₂ under standard conditions (tonnes/m³)

### CO₂ emissions from LNG

If LNG is used as feed at the project activity, CO₂ emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system (\( LE_{\text{LNG}, CO_{2},y} \)) should be estimated by multiplying the quantity of natural gas combusted in the project with an appropriate emission factor, as follows:

\[
LE_{\text{LNG,CO}_2,y} = F_{\text{NG},PJ,y} \times NCV_{NG,y} \times EF_{\text{CO}_2, \text{upstream}, \text{LNG},y}
\]
Where:

\[ EF_{CO2,upstream,LNG,y} \]

Emission factor for upstream CO\(_2\) emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system in year \(y\), in tCO\(_2\)/TJ

Where reliable and accurate data on upstream CO\(_2\) emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system is available, project participants should use this data to determine an average emission factor. Where such data is not available, project participants may assume a default value of 6 tCO\(_2\)/TJ as a rough approximation.\(^5\)

**Emissions reductions**

The emissions reductions are calculated as:

\[ ER_y = BE_y - PE_y - LE_y \]  \( (25) \)

**Changes required for methodology implementation in 2\(^{nd}\) and 3\(^{rd}\) crediting periods**

At the renewal of the crediting period, project participants should follow the latest version of the tool “Assessment of the validity of the original/current baseline and update of the baseline at the renewal of a crediting period”. evaluate whether the project activity continues not to be the baseline scenario, i.e. whether it would have been implemented in the absence of the project activity. The crediting period may only be renewed if the application of the procedure results in that the baseline as determined in the draft CDM-PDD, still apply.

Furthermore, all relevant data contained under “Data and parameters not monitored” should be updated.

**Project activity under a programme of activities**

This methodology is not applicable to project activities under a programme of activities.

**Data and parameters not monitored**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Parameter value</th>
</tr>
</thead>
<tbody>
<tr>
<td>( P_{area, k} )</td>
<td>Tonnes</td>
</tr>
<tr>
<td>Data unit:</td>
<td></td>
</tr>
<tr>
<td>Description:</td>
<td>Production of urea in each of the three most recent years (k) previous to the implementation of the project activity</td>
</tr>
<tr>
<td>Source of data:</td>
<td>Obtained from data logs and urea stock verification records at the project site</td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>Daily urea production calculated based on the ammonia input to the urea plant and periodic (Quarterly) urea stock verification records</td>
</tr>
<tr>
<td>Any comment:</td>
<td>-</td>
</tr>
</tbody>
</table>

### Parameter: CF<sub>existing feedstock, BL</sub>

**Data unit:** tonnes of carbon/tonnes of existing feedstocknaphtha  
**Description:** Carbon fraction of existing feedstock naphtha used in the baseline as feed  
**Source of data:** On-site measurements and plant laboratory records  
**Measurement procedures (if any):** Laboratory analysis of the composition of the feed. In case of more than one feedstock used, the lowest carbon fraction of the feedstock should be used.  
**Any comment:** -

### Parameter: F<sub>existing feedstock, BL, k</sub>

**Data unit:** Tonnes  
**Description:** Quantity of existing feedstock used as feed in each of the three most recent years k previous to the implementation of the project activity  
**Source of data:** Obtained from data logs, measurements and plant records at the project site  
**Measurement procedures (if any):** Feed consumption flow meter. Cross check with feed purchase receipts  
**Any comment:** -

### Parameter: EF<sub>BL, CO2</sub>

**Data unit:** tCO2/TJ  
**Description:** CO₂ emission factor for the baseline fuel that would be used in the furnaces (feed treatment and reforming) in each year y of the crediting period. Chosen as the emission factor of the fuel type with the lowest emission factor among all the fossil fuels used in the furnaces (feed treatment and reforming) in each year y of the crediting period.  
**Source of data:** For the determination of emission factors, guidance from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories should be followed where appropriate, Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available any) may be used if they are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner and the choice should be justified and documented in the CDM-PDD. Laboratory analysis/Online Analysis - If carbon emission factor of fuel used is estimated by laboratory analysis, then the yearly average of fuel composition of respective fuel is to be used to calculate carbon emission factor.  
**Measurement procedures (if any):**  
**Any comment:** -

### Parameter: FC<sub>BL, i, k</sub>

**Data unit:** Tonnes  
**Description:** Quantity of fuel type i consumed in the furnaces (feed treatment and reforming) in each of the most recent three years k previous to the implementation of the project activity
<table>
<thead>
<tr>
<th>Parameter:</th>
<th>$NCV_{i,k}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data unit:</td>
<td>TJ/tonnes</td>
</tr>
<tr>
<td>Description:</td>
<td>Net calorific value of fuel type $i$ consumed in the furnaces (feed treatment and reforming) in each of the most recent three years $k$ previous to the implementation of the project activity</td>
</tr>
<tr>
<td>Source of data:</td>
<td>Project specific data obtained from fuel purchase receipts and/or laboratory tests, is preferred. In the absence of project specific data, local or national data may be used. In the absence of previous options, use data obtained from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories</td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>-</td>
</tr>
<tr>
<td>Any comment:</td>
<td>-</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameter:</th>
<th>$EC_{utility,elec,BL,k}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data unit:</td>
<td>MWh</td>
</tr>
<tr>
<td>Description:</td>
<td>Quantity of electricity consumed during the most recent three years of baseline</td>
</tr>
<tr>
<td>Source of data:</td>
<td>Obtained from data logs books and plant records at the project site</td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>Plant energy meters</td>
</tr>
<tr>
<td>Any comment:</td>
<td>-</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameter:</th>
<th>$rCO_2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data unit:</td>
<td>Ratio</td>
</tr>
<tr>
<td>Description:</td>
<td>CO₂ content in the raw natural gas stream on volume basis</td>
</tr>
<tr>
<td>Source of data:</td>
<td>Official, governmental or public studies; public databases; or written statements from the applicable natural gas processing facility(ies), including the average chemical composition of the raw gas in the reservoirs where the project activity natural gas is extracted from</td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>-</td>
</tr>
<tr>
<td>Any comment:</td>
<td>-</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameter:</th>
<th>$\rho_{CO_2}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data unit:</td>
<td>tonnes/m³</td>
</tr>
<tr>
<td>Description:</td>
<td>Density of the CO₂ gas under standard conditions</td>
</tr>
<tr>
<td>Source of data:</td>
<td>A default value of 0.001978 t CO₂ / m³ CO₂ under standard conditions</td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>$\rho_{CO_2}$</td>
</tr>
<tr>
<td>Any comment:</td>
<td>-</td>
</tr>
</tbody>
</table>
### III. MONITORING METHODOLOGY

**Monitoring procedures**

The data and parameters monitored are essentially related to the main activity of production of urea in the manufacturing facility.

**Data and parameters monitored**

<table>
<thead>
<tr>
<th>Data / Parameter:</th>
<th>$P_{\text{urea, PJ}}$,</th>
<th>Data unit:</th>
<th>Tonnes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Description:</td>
<td>Production of urea in each year $y$ of the crediting period</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Source of data:</td>
<td>Urea stock verification records</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>Daily urea production calculated based on the ammonia input to the urea plant and periodic (Quarterly) urea stock verification records</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Monitoring frequency:</td>
<td>Quarterly</td>
<td></td>
<td></td>
</tr>
<tr>
<td>QA/QC procedures:</td>
<td>Flow meter(s) (Ammonia to urea plant) should be calibrated regularly according to manufacturer’s guidelines. Measurement results should be cross-checked with the periodic urea stock verification carried out by external agencies</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Any comment:</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Data / Parameter:</th>
<th>$F_{\text{NG, PJ}}$,</th>
<th>Data unit:</th>
<th>Mass or volume units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Description:</td>
<td>Consumption of NG/LNG as feed during the year $y$ of the crediting period. If the available data are measured in volume units use the appropriate density of NG/LNG, corrected for temperature and pressure, to calculate the equivalent mass of NG/LNG.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Source of data:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>QA/QC procedures:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Any comment:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Data / Parameter:</td>
<td>F Existing feedstock, PJ_y</td>
<td>Data unit:</td>
<td>tonnes</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>-----------------------------</td>
<td>---------------------</td>
<td>--------</td>
</tr>
<tr>
<td>Description:</td>
<td>Consumption of existing feedstock as feed during the year y of the crediting period</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Source of data:</td>
<td>On-site measurements</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>Flow-rate meters</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Monitoring frequency:</td>
<td>Continuously</td>
<td></td>
<td></td>
</tr>
<tr>
<td>QA/QC procedures:</td>
<td>Meters should be calibrated regularly according to standard procedure or manufacturer’s guidelines. Cross-check with fuel purchase receipts</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Any comment:</td>
<td>Volumetric units should be at normal pressure and temperature (NTP)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Data / Parameter:</th>
<th>CF_NG</th>
<th>Data unit:</th>
<th>Tonnes of carbon/tonnes of NG/LNG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Description:</td>
<td>Carbon content, expressed as weight fraction, of NG/LNG used as feed during year y of the crediting period in tonnes of carbon/tonnes of NG/LNG. Obtained at the project activity</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Source of data:</td>
<td>Derived from the feed composition report provided by the feed supplier</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Monitoring frequency:</td>
<td>Daily</td>
<td></td>
<td></td>
</tr>
<tr>
<td>QA/QC procedures:</td>
<td>The feed composition report provided by the feed supplier should be from a certified laboratory</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Any comment:</td>
<td>-</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Data / Parameter:</th>
<th>CF_naphtha, Existing feedstock, PJ</th>
<th>Data unit:</th>
<th>tonnes of carbon/tonnes of naphtha existing feedstock</th>
</tr>
</thead>
<tbody>
<tr>
<td>Description:</td>
<td>Carbon content, expressed as weight fraction, of existing feedstock naphtha used as feed during year y of the crediting period</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Source of data:</td>
<td>Onsite measurement and Measured at the project activity through plant laboratory records</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>Laboratory analysis of composition of feed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Monitoring frequency:</td>
<td>Daily</td>
<td></td>
<td></td>
</tr>
<tr>
<td>QA/QC procedures:</td>
<td>The plant laboratory should be certified by third party analysis should be carried out in a certified laboratory</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Any comment:</td>
<td>-</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Data / Parameter: $EC_{captive}$
- **Data unit:** MWh
- **Description:** Quantity of electricity obtained from a captive power plant by the project activity during each year $y$ of the crediting period.
- **Source of data:** Measured in the project activity by digital control systems and/or data logs.
- **Measurement procedures (if any):** Electrical Energy Meter
- **Monitoring frequency:** Continuously
- **QA/QC procedures:** Electrical Energy Meter used for measurement should be calibrated regularly as per ISO procedures or according to manufacturer’s guidelines.
- **Any comment:** Applicable only if CDR plant is also being installed.

### Data / Parameter: $E_{Fi,y}$
- **Data unit:** tCO$_2$/TJ
- **Description:** Emission factor of fuel type $i$ used for steam generation in the year $y$.
- **Source of data:** For the determination of emission factors, guidance from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available any) may be used if they are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner and the choice should be justified and documented in the CDM-PDD.
- **Measurement procedures (if any):** For the determination of emission factors, guidance from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available any) may be used if they are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner and the choice should be justified and documented in the CDM-PDD. Laboratory analysis/Online Analysis - If carbon emission factor of fuel used is estimated by laboratory analysis, then the yearly average of fuel composition of respective fuel is to be used to calculate carbon emission factor.
- **Monitoring frequency:** Yearly
- **QA/QC procedures:** Equipments and instruments used in the lab should be calibrated regularly as per ISO procedures or according to manufacturer’s guidelines. If the analysis is carried out by outside agency, it should be a certified/reputed lab.
- **Any comment:** This parameter only needs to be monitored if CDR plant is also being installed.
**Data / Parameter:** $EF_{CO2_i}$

**Data unit:** tCO$_2$/ TJ

**Description:** CO$_2$ emission factor of fuel type $i$ used in the furnaces (feed treatment and reforming) in each year $y$ of the crediting period. Chosen as the emission factor of the fuel type with the highest lowest emission factor among all the $i$ fossil fuels used in the furnaces (feed treatment and reforming) in each year $y$ of the crediting period.

**Source of data:** For the determination of emission factors, guidance from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available) may be used if they are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner and the choice should be justified and documented in the CDM-PDD.

**Measurement procedures (if any):** For the determination of emission factors, guidance from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available) may be used if they are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner and the choice should be justified and documented in the CDM-PDD. Laboratory analysis/Online Analysis—If carbon emission factor of fuel used is estimated by laboratory analysis, then the yearly average of fuel composition of respective fuel is to be used to calculate carbon emission factor.

**Monitoring frequency:** Yearly

**QA/QC procedures:** Equipments and instruments used in the lab should be calibrated regularly as per ISO procedures or according to manufacturer’s guidelines. If the analysis is carried out by outside agency, it should be a certified/reputed lab.

**Any comment:** This parameter only needs to be monitored if CDR plant is also being installed.

**Data / Parameter:** $EF_{CO2\_upstream\_LNG\_y}$

**Data unit:** tCO$_2$/ TJ

**Description:** Emission factor for upstream CO$_2$ emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system in year $y$. 

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27/35
### Source of data:
Where reliable and accurate data on upstream CO$_2$ emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system is available, project participants should use this data to determine an average emission factor. Where such data is not available, project participants may assume a default value of 6 tCO$_2$/TJ as a rough approximation.$^6$

### Measurement procedures (if any):
Where reliable and accurate data on upstream CO$_2$ emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system is available, project participants should use this data to determine an average emission factor. Where such data is not available, project participants may assume a default value of 6 tCO$_2$/TJ as a rough approximation.$^6$

### Monitoring frequency:
Yearly

### QA/QC procedures:
- 

### Any comment:
- 

### Data / Parameter:
$EF_{NG,upstream,CH4}$

### Data unit:
tCH$_4$/TJ

### Description:
CH$_4$ emission factor for upstream fugitive methane emissions from production, transportation and distribution of natural gas feed supplied to final consumers

### Source of data:
Where reliable and accurate national data on fugitive CH$_4$ emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is available, project participants should use this data to determine average emission factors by dividing the total quantity of CH$_4$ emissions by the quantity of fuel produced or supplied respectively.$^8$ Where such data is not available, project participants may use the default values provided in table below. Note that the emission factor for fugitive upstream emissions for natural gas ($EF_{NG,upstream,CH4}$) should include fugitive emissions from production, processing, transport and distribution of natural gas, as indicated in the table provided in the baseline section

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$^8$ GHG inventory data reported to the UNFCCC as part of national communications can be used where country specific approaches (and not IPCC Tier 1 default values) have been used to estimate emissions.
Where reliable and accurate national data on fugitive \( \text{CH}_4 \) emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is available, project participants should use this data to determine average emission factors by dividing the total quantity of \( \text{CH}_4 \) emissions by the quantity of fuel produced or supplied respectively. Where such data is not available, project participants may use the default values provided in table below. Note that the emission factor for fugitive upstream emissions for natural gas (EF\(_{\text{stream upstream, CH}_4}\)) should include fugitive emissions from production, processing, transport and distribution of natural gas, as indicated in the table provided in the baseline section.

<table>
<thead>
<tr>
<th>Data / Parameter:</th>
<th>P\text{steam}</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data unit:</td>
<td>Mpa</td>
</tr>
<tr>
<td>Description:</td>
<td>Pressure of the steam produced in the steam generator</td>
</tr>
<tr>
<td>Source of data:</td>
<td>DCS/log sheet of steam generation plant or power plant</td>
</tr>
<tr>
<td>Monitoring frequency:</td>
<td>Daily</td>
</tr>
<tr>
<td>QA/QC procedures:</td>
<td>The device used for pressure measurement should be calibrated regularly as per ISO procedures or according to manufacturer’s guidelines</td>
</tr>
<tr>
<td>Any comment:</td>
<td>Used to calculate ( E_{\text{steam}} ), the specific enthalpy of the steam at the steam generator outlet, in TJ/tonnes. Calculated as per guidance below</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Data / Parameter:</th>
<th>T\text{steam}</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data unit:</td>
<td>°C</td>
</tr>
<tr>
<td>Description:</td>
<td>Temperature of the steam produced in the steam generator</td>
</tr>
<tr>
<td>Source of data:</td>
<td>DCS/log sheet of steam generation plant or power plant</td>
</tr>
<tr>
<td>Monitoring frequency:</td>
<td>Daily</td>
</tr>
<tr>
<td>QA/QC procedures:</td>
<td>The device used for temperature measurement should be calibrated as per ISO procedures or according to manufacturer’s guidelines</td>
</tr>
<tr>
<td>Any comment:</td>
<td>Used to calculate ( E_{\text{steam}} ), the specific enthalpy of the steam at the steam generator outlet, in TJ/tonnes. Calculated as per guidance below</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Data / Parameter:</th>
<th>P\text{fw}</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data unit:</td>
<td>Mpa</td>
</tr>
<tr>
<td>Description:</td>
<td>Pressure of the feedwater used in the steam generator</td>
</tr>
<tr>
<td>Source of data:</td>
<td>DCS/log sheet of steam generation plant or power plant</td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>-</td>
</tr>
<tr>
<td>Monitoring frequency:</td>
<td>-</td>
</tr>
<tr>
<td>QA/QC procedures:</td>
<td>-</td>
</tr>
<tr>
<td>Any comment:</td>
<td>-</td>
</tr>
</tbody>
</table>

\( ^9 \) GHG inventory data reported to the UNFCCC as part of national communications can be used where country specific approaches (and not IPCC Tier 1 default values) have been used to estimate emissions.
### Monitoring frequency:
Daily

### QA/QC procedures:
The device used for pressure measurement should be calibrated regularly as per ISO procedures or according to manufacturer’s guidelines

### Any comment:
Used to calculate $E_{\text{feedwater}}$, the specific enthalpy of the feed water at the steam generator inlet, in TJ/tonnes

<table>
<thead>
<tr>
<th>Data / Parameter:</th>
<th>$T_{\text{fw}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data unit:</td>
<td>°C</td>
</tr>
<tr>
<td>Description:</td>
<td>Temperature of the feedwater used in the steam generator</td>
</tr>
<tr>
<td>Source of data:</td>
<td>DCS/log sheet of steam generation plant or power plant</td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>-</td>
</tr>
<tr>
<td>Monitoring frequency:</td>
<td>Daily</td>
</tr>
<tr>
<td>QA/QC procedures:</td>
<td>The device used for temperature measurement should be calibrated as per standard ISO procedures or according to manufacturer’s guidelines</td>
</tr>
<tr>
<td>Any comment:</td>
<td>Used to calculate $E_{\text{feedwater}}$, the specific enthalpy of the feed water at the steam generator inlet, in TJ/tonnes</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Data / Parameter:</th>
<th>$PE_{\text{CDR, elec}}, FC_{\text{CDR, steam}, i}, y$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data unit:</td>
<td>Mass or volume units (CO₂)</td>
</tr>
<tr>
<td>Description:</td>
<td>Emissions due to the production of electricity used for the operation of the CDR plant in each year $y$ of the crediting period. Amount of fossil fuel of type $i$ used in the captive power plant in each year $y$ of the crediting period.</td>
</tr>
<tr>
<td>Source of data:</td>
<td>As per the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption” Measured at the captive power plant.</td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>As per the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption” Flow-rate meters, mass meters, cross-check with fuel purchase receipts.</td>
</tr>
<tr>
<td>Monitoring frequency:</td>
<td>As per the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption” Continuously</td>
</tr>
<tr>
<td>QA/QC procedures:</td>
<td>Meters should be calibrated regularly according to manufacturer’s guidelines.</td>
</tr>
<tr>
<td>Any comment:</td>
<td>-</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Data / Parameter:</th>
<th>$FC_{\text{CDR, steam}, i}, y$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data unit:</td>
<td>Mass or volume units</td>
</tr>
<tr>
<td>Description:</td>
<td>Amount of fuel type $i$ consumed in the steam generator in each year $y$ of the crediting period</td>
</tr>
<tr>
<td>Source of data:</td>
<td>Measured at the steam generator site</td>
</tr>
<tr>
<td>Measurement procedures (if any):</td>
<td>Flow-rate meters/mass meters cross-check with fuel purchase receipts.</td>
</tr>
<tr>
<td>Monitoring frequency:</td>
<td>Continuously</td>
</tr>
<tr>
<td>QA/QC procedures:</td>
<td>Meters should be calibrated regularly according to standard procedure or manufacturer’s guidelines. Cross-check with fuel purchase receipts</td>
</tr>
<tr>
<td>Any comment:</td>
<td>-</td>
</tr>
</tbody>
</table>
**Data / Parameter:** $PE_{\text{Heat},i,y}$

- **Data unit:** $\text{tCO}_2$/year, Mass or volume units
- **Description:** Emissions due to fuel consumption for the purpose of production of thermal energy in the furnaces (feed treatment and reforming) after deducting the CO$_2$ recovered by the CDR plant (if any) in each year $y$ of the crediting period, in tCO$_2$. Quantity of fuel type $i$ consumed in the furnaces (feed treatment and reforming) in each year $y$ of the crediting period.
- **Source of data:** As per the “Tool to calculate project or leakage CO$_2$ emissions from fossil fuel combustion” On-site measurements
- **Measurement procedures (if any):** As per the “Tool to calculate project or leakage CO$_2$ emissions from fossil fuel combustion” Flow rate meters
- **Monitoring frequency:** As per the “Tool to calculate project or leakage CO$_2$ emissions from fossil fuel combustion” Continuously
- **QA/QC procedures:** Meters should be calibrated regularly according to standard procedure or manufacturer’s guidelines.
- **Any comment:** Volumetric units should be at normal pressure and temperature

**Data / Parameter:** $NCV_{i,y}$

- **Data unit:** TJ/mass or volume units
- **Description:** Average net calorific value of fuel type $i$ and NG/LNG respectively, in year $y$ of the crediting period
- **Source of data:** Project specific data obtained from fuel purchase receipts and/or laboratory tests, is preferred. In the absence of project specific data, local or national data may be used. In the absence of previous options, use data obtained from in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories
- **Measurement procedures (if any):** -
- **Monitoring frequency** The calorific value of the respective fuel is measured daily and monthly average of calorific value is calculated by averaging daily value. Yearly average of calorific value is calculated by averaging monthly value
- **QA/QC procedures** -
- **Any comment** -

**Data / Parameter:** $SC_{\text{CDR},y}$

- **Data unit:** tonnes
- **Description:** Quantity Demand of steam required for the operation of the CDR plant in each year $y$ of the crediting period
- **Source of data:** DCS/log sheet of ammonia plant
- **Measurement procedures (if any):** Use steam flow meters
- **Monitoring frequency:** Continuously
- **QA/QC procedures:** Steam Flow Meter used for measurement should be calibrated regularly as per standard ISO procedures or according to manufacturer’s guidelines
- **Any comment:** -
### Data / Parameter: \( TEP_{\text{ captive},y} \)

**Data unit:** MWh  
**Description:** Total electricity produced by the captive power plant in year \( y \).  
**Source of data:** Measured at the captive power plant through electricity meters. Cross-check with electricity purchase receipts, if any.  
**Measurement procedures (if any):** 
**Monitoring frequency:** Continuously  
**QA/QC procedures:** Electricity flow meter used for measurement should be calibrated regularly as per ISO procedures or according to manufacturer’s guidelines.  
**Any comment:** 

### Data / Parameter: \( TSP_{\text{steam},y} \)

**Data unit:** Tonnes  
**Description:** Total amount of steam produced by the steam generator in each year \( y \) of the crediting period.  
**Source of data:** Measured at the steam generator site through steam flow meters  
**Measurement procedures (if any):** Steam flow meters  
**Monitoring frequency:** Continuously  
**QA/QC procedures:** Steam flow meter used for measurement should be calibrated regularly as per standard ISO procedures or according to manufacturer’s guidelines.  
**Any comment:** 

### Data / Parameter: \( EC_{\text{utility,elec},y} \)

**Data unit:** MWh  
**Description:** Quantity of electricity consumed by the project activity in each year \( y \) of the crediting period.  
**Source of data:** Plant records and log books  
**Measurement procedures (if any):** Energy meters  
**Monitoring frequency:** Continuously  
**QA/QC procedures:** Energy meters used for measurement should be calibrated regularly as per standard procedures or according to manufacturer’s guidelines.  
**Any comment:** 

### Data / Parameter: \( SC_{\text{utility,steam},y} \)

**Data unit:** Tonnes  
**Description:** Quantity of steam consumed in each year \( y \) of the crediting period.  
**Source of data:** Plant records and log books  
**Measurement procedures (if any):** Steam flow meters  
**Monitoring frequency:** Continuously  
**QA/QC procedures:** Steam flow meters used for measurement should be calibrated regularly as per standard procedures or according to manufacturer’s guidelines.  
**Any comment:** 

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32/35
### Data / Parameter: \( T_{\text{SP,utility,steam,y}} \)
- **Data unit:** Tonnes
- **Description:** Quantity of steam produced by the steam generator used for utility steam in each year \( y \) of the crediting period
- **Source of data:** Measured at the steam generator site through steam flow meters
- **Measurement procedures (if any):**
- **Monitoring frequency:** Continuously
- **QA/QC procedures:** Steam flow meter used for measurement should be calibrated regularly as per standard procedures or according to manufacturer’s guidelines
- **Any comment:**

### Data / Parameter: \( FC_{\text{utility,steam,i,y}} \)
- **Data unit:** Mass or volume units
- **Description:** Quantity of fuel type \( i \) consumed in the steam generator used for utility steam in each year \( y \) of the crediting period
- **Source of data:** Measured at the steam generator site
- **Measurement procedures (if any):** Flow-rate meters, mass meters
- **Monitoring frequency:** Continuously
- **QA/QC procedures:** Meters should be calibrated regularly according to standard procedure or manufacturer’s guidelines. Cross-check with fuel purchase receipts
- **Any comment:**

### Data / Parameter: \( P_{\text{utility,steam}} \)
- **Data unit:** Mpa
- **Description:** Pressure of the steam produced in the steam generator used for utility steam
- **Source of data:** DCS/log sheet of steam generation plant or power plant
- **Measurement procedures (if any):**
- **Monitoring frequency:** Daily
- **QA/QC procedures:** The device used for pressure measurement should be calibrated regularly as per standard procedures or according to manufacturer’s guidelines
- **Any comment:** Used to calculate \( E_{\text{utility,steam}} \), the specific enthalpy of the steam at the steam generator outlet used for utility steam, in TJ/tonnes

### Data / Parameter: \( T_{\text{utility,steam}} \)
- **Data unit:** °C
- **Description:** Temperature of the steam produced in the steam generator used for utility steam
- **Source of data:** DCS/log sheet of steam generation plant or power plant
- **Measurement procedures (if any):**
- **Monitoring frequency:** Daily
- **QA/QC procedures:** The device used for temperature measurement should be calibrated as per standard procedures or according to manufacturer’s guidelines
- **Any comment:** Used to calculate \( E_{\text{utility,steam}} \), the specific enthalpy of the steam at the steam generator outlet used for utility steam, in TJ/tonnes
### Data / Parameter: \( P_{\text{utility, fw}} \)

**Data unit:** | Mpa |
---|---|
**Description:** | Pressure of the feedwater used in the steam generator used for utility steam |
**Source of data:** | DCS/log sheet of steam generation plant or power plant |
**Measurement procedures (if any):** |  |
**Monitoring frequency:** | Daily |
**QA/QC procedures:** | The device used for pressure measurement should be calibrated regularly as per standard procedures or according to manufacturer’s guidelines |
**Any comment:** | Used to calculate \( E_{\text{utility, feedwater}} \), the specific enthalpy of the feed water at the steam generator inlet used for utility steam, in TJ/tonnes |

### Data / Parameter: \( T_{\text{utility, fw}} \)

**Data unit:** | °C |
---|---|
**Description:** | Temperature of the feedwater used in the steam generator used for utility steam |
**Source of data:** | DCS/log sheet of steam generation plant or power plant |
**Measurement procedures (if any):** |  |
**Monitoring frequency:** | Daily |
**QA/QC procedures:** | The device used for temperature measurement should be calibrated as per standard procedures or according to manufacturer’s guidelines |
**Any comment:** | Used to calculate \( E_{\text{utility, feedwater}} \), the specific enthalpy of the feed water at the steam generator inlet used for utility steam, in TJ/tonnes |

### Data / Parameter: \( EF_{\text{utility, elec, y}} \)

**Data unit:** | tCO2/MWh |
---|---|
**Description:** | Emission factor for electricity consumption in utilities |
**Source of data:** | Measured at electricity consumption sites |
**Measurement procedures (if any):** | Tool to calculate baseline, project and/or leakage emissions from electricity consumption |
**Monitoring frequency:** | Daily |
**QA/QC procedures:** |  |
**Any comment:** |  |

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## History of the document

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Nature of revision(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.0.0</td>
<td>20 July 2012</td>
<td>EB 68, Annex # 1. Revision to include other feedstocks other than naphtha; 2. Revision in the applicability conditions for the production, steam and electricity consumption and subsequent revision to the emission reduction calculation; 3. Introduces provisions for the use of this methodology in a project activity under a PoA; 4. Editorial corrections.</td>
</tr>
<tr>
<td>2.1</td>
<td>EB 39, Para 15 14 May 2008</td>
<td>1. In variable description section of equation 2 change $BE_{Urea,y}$ to $BS_{Urea,y}$. 2. Delete text “after deducting the CO₂ recovered by the CDR plant (if any)” while describing emissions from thermal energy (above equation 12). 3. Note added below table 2 “The emission factor should be selected in order to ensure conservativeness in estimation of emission reduction.” 4. In section III monitoring methodology first para, the sentence mentioning that the parameters should be monitored on daily basis, is deleted. 5. In table “data and parameters monitored” the data unit of $CF_{NG}$ is changed from “tonnes of carbon/tonnes of hydrogen” to “tonnes of carbon/tonnes of NG”.</td>
</tr>
<tr>
<td>02</td>
<td>EB 35, Para 24 19 October 2007</td>
<td>Revision to incorporate the use of the “Tool to calculate emission factor for an electricity system”</td>
</tr>
<tr>
<td>01</td>
<td>EB 31, Annex 4 4 May 2007</td>
<td>Initial adoption</td>
</tr>
</tbody>
</table>